REVISED FINAL

A CLOSEOUT EVALUATION OF THE J4 DEVELOPMENT PROJECT

Prepared for
Petronas Carigali

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PREFACE

This evaluation of the J4 Development Project compares the project's performance with that of similar projects in Industry and with Petronas' average performance. Furthermore, since the project is complete, we also compare the project's actual performance with the estimates provided to management at sanction. To supply industry benchmarks, we used IPA's Upstream Project Evaluation System (PES®)[1] models. Based on this analysis, past IPA research, and input from the project team, we also provide lessons learned that can be used to improve future project performance. This report establishes the final benchmarks for the J4 Development Project. It is important to note that IPA did not conduct a pre-sanction evaluation of this project, and the assessment of Project Drivers was based on team's assessment of level of preparedness on April 7, 2007, when the J4 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 J4 Development Project. Using these comparison databases, we present benchmarks that reflect the industry of today. To fully understand the project's performance, we also used Upstream Cost Engineering Committee (UCEC[2]) data.

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

- *Project Drivers* – Practices employed in the project's definition phase that drove the project's performance
- *Project Execution Discipline* – Practices employed in the project's 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 the results of a Lessons Learned discussion conducted with the project team as part of the project interview. 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 June 19, 2008 and November 24, 2008, in the project offices in Kuala Lumpur, Malaysia. Project team members present at this meeting included Noraini Kamil (Head of Project Services), Mohamed Jaafar Johari (Document Controller), Azman Imran (HSE), Ahmad Saufi Faisaluddin (Project Controller), Aimaduddin Mazli (Pipeline Engineer), Simon Christian Kurniawan (Senior Development Geologist), Li Hu (Production Technologist), Abdul Thani Sulai (Subsurface FDP Small Field Development Lead), Arwansyah (Senior Drilling Engineer), Norhishem Safiin (Senior Well Completion Engineer), Abdul Razak Ariffin (Staff Project Management), Norlin Ghazali (Reservoir Engineer), Radin Dzulfakar (Electrical Engineer), Mohamad Faizal Daud (Project Controller), Argeo Alecha (Senior Field Engineer), Mohamed Sharil Falzin (Technical Studies Executive), Tang Sing Ling (Geologist), Hadijanto Jogi B (Senior Mechanical and Process Engineer), Andrew Chin (Senior Structural Engineer).

[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.

Trung Ghi represented IPA. Although members of the project team provided information, the interpretation and analysis are IPA's and do not necessarily reflect the views of those interviewed. For more information, contact Trung Ghi of IPA Australia at +61-3-9458-7315 or tghi@ipaglobal.com.

EXECUTIVE SUMMARY

This report evaluates the performance of the J4 Development Project, which was executed in Malaysia. Petronas Carigali Sdn Bhd (PCSB[3]) operates the fields under an existing production-sharing contract (PSC) with the Government of Malaysia. The J4 field is located offshore Sarawak 170 km northwest of Bintulu in a water depth of 53 m. The field was discovered in 1978 based on 2D seismic data and later explored with one exploration and four appraisal wells.

The objective of the J4 Development Project was to develop the J4 field to maintain the PSC contractual agreements. The first oil date of July 2008 was set in anticipation of decreasing production to the PSC. The subsurface planned scope consists of eight development wells and one appraisal well. The reserves were estimated to be 8.6 million stock tank barrels (MMstb) of oil with a 17 percent recovery factor. A small amount of gas (27 billion cubic feet [bcf]) was also planned to be recovered. In total, 13 million barrels of oil equivalent (MMBOE) would be developed. Currently, the project team has drilled and completed seven development wells with a new resource production estimate (RPE) of 21 MMBOE, which is an increase in recoverable volume of about 50 percent.

J4 was developed as a satellite oil and gas drilling platform to the D35 platform. The first oil date of July 2008 was later delayed to November 2008; the project team achieved first oil in October 2008. The total estimated capital cost of the J4 Development Project at sanction was RM631 million, including RM214 million for the J4 drilling platform (J4DR-A), RM122 million for the intrafield pipeline, and RM295 million for the drilling program. The J4DR-A platform was completed for RM243 million and the pipeline was installed for RM139 million. The drilling program (7 development wells) was completed in May 2009 for RM331 million. The additional drilling scope is anticipated to cost RM55 million per well or a total of RM 219 million. The drilling cost[4] grew by 2 percent and the facilities costs grew by 12 percent.[5]

BENCHMARKS

The tables in this section summarise the results of our analysis. The tables present the J4 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 J4 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.

[3] PETRONAS carries out exploration, development, and production activities in Malaysia through PSC with a number of international oil and gas companies and with its wholly owned subsidiary, Petronas Carigali Sdn Bhd.
[4] Not including additional drilling scope – four additional development wells.
[5] Cost deviation is normalized to the estimate date (May 2007).

Table 1
Summary of Safety and Cost Outcome Metrics for the J4 Development Project

Outcome Metric	J4 Development Project		Industry Average	Top Quartile
	Estimated at Sanction	Actual		
Safety (per 200,000)				
Recordable Incident Rate	Not App.	0.25	1.03[6]	Not Avail.
DART Rate[7]	Not App.	0.00	0.37[8]	Not Avail.
RM/BOE Metrics (Money of the Day) (Level 1)				
Asset Development Cost RM/BOE[9,10] (Index)	51 (1.82)	48 (1.71)	28 (1.00) A	17 (0.61)
Non-Export Facilities RM/BOE[11] (Index)	29 (1.93)	32 (2.13)	15 (1.00)	9 (0.61)
Wells RM/BOE (Index)	22[12] (1.69)	16[13] (1.19)	13[14] (1.00)	8 (0.60)
Concept Cost Effectiveness (Level 2) – US$ Million				
Wells (Cost Index)	78[15] (1.38)	91[16] (0.97)	56 (1.00) E[17] 93 (1.00) A	38 (0.68) E 64 (0.68) A
Component Cost Effectiveness (Level 3) (RM million)				
Total Facilities (Weighted Cost Index)	337 (1.02)	382 (1.16)	330 (1.00)	Not Avail.
– **J4DP-A (Cost Index)[18]**	214 (1.13)	243 (1.28)	190 (1.00)	Not Avail.
– **Pipeline (Cost Index)**	123 (0.86)	139 (0.97)	140 (1.00)	110 (0.79)
Wells (Cost Index)	78[14] (1.02)	91[15](1.05)	76 (1.00) E 86 (1.00) A	58 (0.75) E 65 (0.75) A
Deviation				
Asset	Not App.	7 percent	-1 percent	-1 percent
Facilities	Not App.	12 percent	1 percent	1 percent
Wells	Not App.	2 percent	2 percent	1 percent

[6] Industry metrics from IBC 2008
[7] DART: A work-related injury or illness resulting in days away from work, restricted duties, or job transfer.
[8] Industry metric from IBC 2008
[9] Excludes export and onshore costs.
[10] Asset $/BOE is additive of the facilities $/BOE and the wells $/BOE.
[11] Non-Export Facilities $/BOE is based on estimated life-of-project production stream (base for which the team designed the facilities).
[12] Wells $/BOE is based on the "estimate" life-of-project production stream.
[13] Wells $/BOE is based on the "actual" life-of-project production stream, or the estimate that is updated at the start of production.
[14] The industry benchmark for the "actual" is lower than the estimate (in US$[2003]) because of the increase in RPE from sanction to completion of the drilling campaign. However, because of the different escalation factors (a difference of 30 percent) at sanction and at the completion of the project, the industry average $/BOE metric is coincidentally the same.
[15] Based on nine wells recovering 13 MMBOE (estimated).
[16] Based on eight wells (J4-A09 well is suspended) recovering 21 MMBOE (actual).
[17] The RPE and well number change from estimate to actual changes the benchmarks for several metrics. The different benchmarks are designated E for estimate or A for actual.
[18] Benchmark is based on UCEC data.

At the component level, the pipeline cost is similar to Industry. The facilities costs were benchmarked using Upstream Cost Engineering Committee (UCEC[19]) metrics because the hydrocarbon throughput for the J4DR-A platform is small relative to the wellhead platforms (WHPs) in our WHP cost model. Therefore, the platform benchmark should be interpreted with caution, as the cost index provided in Table 1 does not take into account variables such as water depth, maximum wave height, hydrocarbon throughput, and number of slots. Based on the UCEC weight metrics, the jacket and topside costs are more expensive than projects in Asia. In addition, based on the given water depth and topside weight, the jacket weight is more than 50 percent heavier than a typical similar project executed in Asia. Therefore, if the platform designs were optimised, possible savings could be made. The high facilities component cost index suggests that the WHP could have been executed more efficiently; the even higher RM/BOE index suggests either that the concept selection could have been better or that this is an expensive field to develop.

Compared to similar projects, the J4 wells component cost was slightly more expensive than Industry for similar wells. The wells concept cost was industry average for a similar reservoir complexity. On average, a similar industry project[20] for this field size would recover approximately 4 MMBOE per well. The recovery per well is 3 MMBOE for the J4 field. Therefore, the concept (number of wells) drove the Wells RM/BOE, which indicates that the industry would typically pay less to develop similar size reservoirs as the J4 field.

The J4 Development Project incurred cost growth during execution for both facilities and wells scope. The cost growth was predominately driven by late arrivals of the installation rig and vessels as well as major late changes in the wells design and operational issues during drilling.

Table 2
Summary of Schedule Outcome Metrics for the J4 Development Project

Outcome Metric	J4 Development Project		Industry Average	Top Quartile
	Planned at Sanction	Actual		
Effectiveness				
FEL 3 Duration	2.1 months	2.1 months	Not Avail.	Not Avail.
Facilities Execution Duration (Schedule Index)	14 months (0.70)	17 months (0.85)	20 months (1.00)	17 months (0.85)
Well Construction Duration (Schedule Index)	203 days[21] (0.93)	236 days[22] (1.19)	219 days (1.00) E 198 days (1.00) A	169 days (0.77) E 152 days (0.77) A
Cycle Time Duration	26.8 months	30.2 months	Not Avail.	Not Avail.
Deviation				
Facilities Execution Schedule	Not App.	21 percent	4 percent	-13 percent
Well Construction Schedule	Not App.	16 percent	Not App.	Not App.

[19] 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.
[20] Based on a comparison dataset, which consists of 22 oil and gas projects in similar water depths as the J4 Development Project.
[21] Based on nine wells.
[22] Based on eight wells (J4-A09 well is suspended).

As shown in Table 2, the facilities execution was much faster than Industry. Moreover, the engineer, procure, construct, and commission (EPCC) lump-sum contracting strategy adopted by the project team significantly improved the execution schedule versus the typical PCSB contracting strategy of bidding the procure, construct, and commission (PCC) scope after the detailed engineering phase. Based on the 2007 system benchmarking for Petronas, the J4 Project team reduced its execution schedule by at least 6 to 10 months (from the tendering and bidding process for the PCC) by adopting the EPCC lump-sum strategy. The team was, however, challenged to meet an aggressive first oil date with limited resources. As a result, the execution schedule slipped by 21 percent, or 3 months.

The planned wells construction duration of 203 days was industry average. The team planned to complete each well in 23 days. The drilling campaign took 236 days to complete which is approximately 19 percent slower than Industry. Moreover, the original scope of nine wells (including an appraisal well) was reduced to seven wells[23] after an optimisation study was conducted post sanction. The drilling team encountered operational issues, so each well took, on average, 30 days. Therefore, the drilling duration slipped by approximately 16 percent.

Table 3
Summary of Life-of-Project Production Stream (Resource Promise) and Operability Metrics for the J4 Development Project

Outcome Metric	J4 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	13.3 MMBOE	56 percent	-10 percent	-7 percent
Production Attainment in Months 7-12[24]	Not Avail.	Not Avail.	80 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 of 13.3 MMBOE was downgraded after the completion of the second well by 9 percent in the overall resource promise including gas recovery. Following the completion of the drilling campaign in May 2009, the recoverable volume increased to 20.7 MMBOE (or 56 percent) because the number of reservoirs had increased from three to five and incorrect fault connectivity assumptions (leaking faults instead of sealing faults). The industry and PCSB averages are downgrades of 10 percent and 7 percent, respectively. Although the increase in recoverable volumes is a good outcome for the J4 project team, the significant change is a concern because the subsurface basic data had incorrect assumptions that might have led to a downgrade; beyond that, recoverable volume underestimation can lead a company to decide not to develop a worthwhile field. The aggressive project schedule may have attributed to the incomplete subsurface basic data development.

[23] Eight wells were drilled (J4-A09 was suspended).
[24] Production attainment data were not available at the time of the interview; they will be collected 12 months after startup.

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 J4 Development Project's drivers and asset development practices.

Table 4
Summary of Project Practices and Drivers for the J4 Development Project (at Sanction)

Driver or Practice	J4 Dev. Project	Industry Average	PCSB Average	Best Practice
Appraisal Strategy	Moderate	Moderate 53 percent	Moderate 83 percent	Not App.
Reservoir Complexity	45	39	37	Not App.
Wells Complexity	45 (41 to 51)	52	49	Not App.
FEL Index – Asset	5.58 (*Good*)	6.55 (*Fair)*	8.08 *(Screening)*	4.00 to 5.50
Reservoir	5.54	6.00	6.86	4.50 to 5.50
Wells	5.29	6.67	7.13	5.00 to 6.00
Facilities (Platform)	5.75 *(Good)*	7.33 *(Fair)*	9.11 *(Screening)*	3.75 to 4.75
Pipeline	5.00 *(Good)*	6.12 *(Fair)*	7.78 *(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	57 percent	80 percent	Not App.
Team Experience With Facilities Technology	New to Team	13 percent	20 percent	Not App.
Technical Innovation of Wells	Routine	43 percent	50 percent	Not App.
Team Experience With Wells Technology	New to Team	21 percent	33 percent	Not App.
Facilities VIPs Used	11 percent	27 percent	9 percent	40 to 60 percent
Subsurface VIPs Used	33 percent	35 percent	19 percent	Not App.

The appraisal work to acquire basic data was sufficient to be classified as *Moderate*. The subsurface team achieved a *Good* Reservoir Front-End Loading (FEL) Index, which is better than Industry. However, an ongoing optimisation study after sanction caused scope and design changes to the wells program, which impacted the drilling campaign cost predictability. Facilities FEL lagged *Best Practical* due to a lack of resources to adequately complete FEL deliverables in the aggressive time frame. Wells FEL was *Best Practical* at sanction, driven by routine well designs and supported by an established drilling and completion division. Moreover, the team was integrated, despite the turnover of key lead team members, which led to better communication flow within the team and therefore mitigating against the aggressive schedule.

The J4 Development scope was considered relatively routine for the project team. PCSB has ample experience in the region with installing WHPs and pipelines. In fact, the platform design was from a similar project (Angsi C&E Project) which enabled the J4 Project team to work around the lack of experienced staff and schedule pressure.

The wells design was also considered relatively routine within PCSB. The technology employed is industry-proven, but new to the relatively young team members. This risk was minimised by support from senior engineers in the company and various technical peer reviews conducted during the project.

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 design changes. Table 5 summarises the project execution discipline for the J4 Development Project.

Table 5
Summary of the J4 Development Project's Execution Discipline

Project Execution Discipline	J4 Dev. Project	Industry Average	PCSB Average	Best Practice
Project Control Index (PCI)	*Fair*	*Poor*	*Poor*	*Good*
Project Manager Turnover	Yes	38 percent of projects	14 percent of projects	No Turnover
Major Late Design Changes	Yes	64 percent of projects	100 percent of projects	None

The J4 Development Project's PCI rating was *Fair*, which is better than industry and PCSB average project controls. Integral to the project was the proactive management of contractors led by the project controller and the project team to ensure the project met its objectives. Moreover, the integrated team and project controls allowed for smooth project execution despite high turnover in key roles. However, the project was plagued with major late changes in the wells design, which attributed to the cost and schedule deviation.

CONCLUSIONS

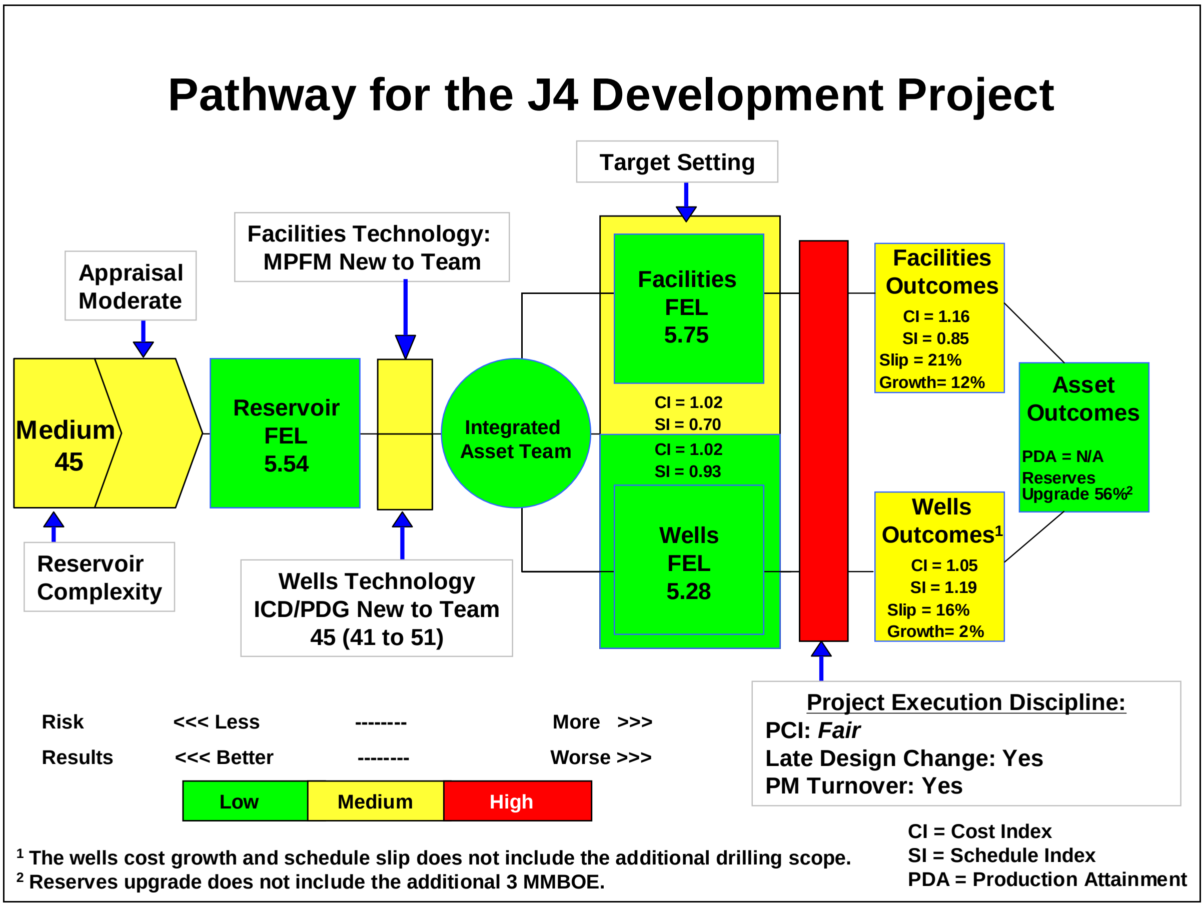

Figure 1

IPA assessed the J4 Development Project's drivers and the level of 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 J4 field development was recognised by senior management as significant and a strategic project, because of the forecast shortfall in PSC supply. The project team faced two key challenges in execution: (1) pursuing an *Aggressive* schedule, and (2) high turnover in key roles.

The J4 Development Project had better than industry-average project definition and had moderate targets for cost. The project team achieved sound results in competitiveness and predictability. However, the execution schedule was aggressive, driven by the first oil date. The integrated team and industry-proven technology benefited the young and inexperienced team members. Moreover, the standard design from a similar project enabled the J4 Project team to work around the lack of staffing and schedule pressure.

LESSONS LEARNED AND RECOMMENDATIONS

Based on our analysis of historical industry performance and our assessment of the J4 Development Project, we present the following key lessons for future projects.

1. *Good FEL and integrated teams assist schedule-driven projects*. Historically, projects with a *Good* FEL delivered faster. Combined with an integrated team, the aggressive schedule risks were minimised. This is because basic data had been prepared and were communicated between the various functions and disciplines.
2. *Leveraged design from the Angsi Project contributed to the J4 Development Project's competitive cost and schedule performance*. Most of the design had already been completed from the Angsi Project, and the J4 team was able to modify them to suit the J4 environment. This approach was much faster than the time the team would have needed to start the J4 design from scratch, and was especially helpful given the project's time constraints.
3. *Adequate project controls and proactive contractor management kept the project aligned with business and project objectives*. The small but proactive team worked closely with the contractors and thereby mitigated execution risks effectively and efficiently.
4. *Minimise scope and design changes during execution by completing subsurface studies before commencing FEED.* Providing basic subsurface data early improves operability and production attainment. Historically, projects that obtained all basic data before entering FEED more often achieved their business objectives than did projects that lacked timely basic data.

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INTRODUCTION

OBJECTIVES

The business objective for the J4 Development Project was to "keep-up with the demand in the PSC by exploiting 8.6 million stock tank barrels (MMstb) of oil in July 2008"[25].

The J4 Development Project objective was to develop the J4 oil field with a 4-legged drilling platform and drill 6 development wells to recover oil from J4. The full well stream (FWS) was to be sent to the D35 platform, about 53 km away. The business mandated that the project achieve first oil by July 2008.

Overall, the project achieved its objectives but did not reach first oil until October 2008 with approximately 7 percent asset cost growth. The wells program has slipped the planned schedule by 16 percent. The drilling cost estimate at sanction has grown from US$78 million to US$91 million. Overall the project increased the recoverable volume by 56 percent (or 21 MMBOE).

FIELD DESCRIPTION AND HISTORY

The hydrocarbon accumulation is contained in four stacked reservoir units composed of fluvial clastics of the Miocene Cycle II stratigraphic sequence. The field forms a structurally complex anticline subdivided into several fault blocks, three of which are proven oil-bearing.

The main drive mechanism is expected to be solution gas and gas cap. A peak oil rate of 5,000 barrels per day (bpd) is expected. In view of the light crude (41° API gravity), increasing gas-to-oil ratio (GOR) and low-water cut, development wells are expected to be capable of sustaining natural flow throughout the 9-year production life.

PROJECT SCOPE

The J4 Development Project scope includes the following elements:

- An unmanned wellhead platform (WHP), J4DR-A, consisting of a four-legged steel template jacket. J4DR-A was configured with 12 x 660-mm diameter (or 26-inch) conductor slots. Six slots will be utilised for J4 development while the rest are provisions for future development.
- The drilling program at sanction was to drill 8 (2 horizontal and 6 deviated) development wells and 1 appraisal well to the adjacent section, which is divided by a fault. After an optimisation study during the execution phase, the drilling scope was reduced to 6 development wells and 1 appraisal well.
- An intrafield pipeline, 10 inch x 53 km carbon steel (from J4DR-A to D35 riser platform) was installed.

[25] Extracted from the J4 Project Execution Plan

TECHNOLOGY

The J4 Development Project team used the following technology in the facilities and wells design:

- Multiphase Flowmeter (MPFM),
- Provision for Multiphase Pump (MPP), Compact Manifold with Diverter Valves
- Integrated Control Device (ICD) and Production Downhole Gauges (PDG)

PROJECT HISTORY

Field Discovery and Appraisal

- 1978: J4 field was discovered based on 2D seismic data and later J4-1 exploration well.
- Over the next few years, four appraisal wells were drilled to delineate the field structure, but only the J4-4 well confirmed the principal oil continuation found in the J4-1 well. The J4-2 and J4-3 wells found only gas reservoirs, and the J4-5 well, drilled west of the J4-1 well, was considered dry with only a small amount of gas.
- 1985: 3D seismic data were acquired, showing significantly more definition of the highly complex fault pattern and firming up the hydrocarbon distribution (amplitude anomaly) in the main part of the field.
- 1992 to 1993: About 100 km^2 of the data were re-processed in-house by Digicon through application of residual static, 3D DMO, and better 3D migration and zero phasing techniques.
- June 2005: Shell's field license expired, and the field was transferred in July to PCSB's small field development division to develop and exploit.

Select and Define Phase (Preparing the FDP)

- 10 March 2006: The Static Model results were endorsed by the Field Development Review Committee (FDRC).
- March 2006: The core project team was formed (Lead for FDP, Facilities, Project Services, Drilling, and Ops rep).
- May 2006: The Static Model results were endorsed by the Petronas Management Unit (PMU).
- 27 September 2006: The Dynamic Model results were endorsed by FDRC.
- 1 November 2006: The Dynamic Model results were endorsed by PMU.
- 25 January 2007: The FDP was endorsed by the Petronas Investment Review Committee (PIRC).
- During Front-End Engineering Design (FEED), the drilling team was unsure if it could get a drilling jack-up (JUP) rig, which was required for the Angsi WHP design. The project team considered using a tender assist drilling (TAD) rig and made allowances to the design to accommodate the TAD if required. Eventually the project team

located a JUP rig, and therefore the WHP did not require the additional structural steel for a TAD rig.

The WHP design did not have a helideck allocated, as the production team had not requested one. However, when the design was submitted to PCSB management for approval, a helideck was requested because of the long distance from the D35 platform. The team had about 1 month to make the changes before sanction.

- At the end of FEED, the production requirement dropped from 11,000 bpd to 7,000 bpd because the production profile had changed after completing the optimisation study. The team did not change the design due to time constraints.

Project Sanction

- 21 March 2007: Board approval (project sanction) was given to the J4 Development Project. The project obtained special sanction consideration because the FDP had not been written yet. However, PMU and the various management committees had seen the team's work in December 2006. At this point, PMU requested further optimisation to be conducted to improve well numbers and location.

- The recoverable resource at sanction is 8.6 MMstb of oil and 27 bcf of gas or a total of 13.2 MMBOE.

Project Execution

- 9 April 2007: The FDP was formally approved. J4 was planned to be developed on a standalone basis and the field was expected to be on stream in July 2008. Long-lead items were purchased during this time.
- Early 2007: The subsurface manager lead turned over twice due to promotions and reallocation to another project.
- May 2007: The optimisation study indicated that the nine single-string wells could be reduced to seven dual- and single-string wells, which led to a scope change. An appraisal well was included in the drilling program, as requested by PMU, to understand the adjacent block. The recoverable resource was expected to be 11.2 MMstb and 19.7 bcf of gas or a total of 14.6 MMBOE. This is an increase of 10 percent relative to the sanctioned estimate.
- July 2007: The project controller was replaced because of internal progression.
- February 2008: The facilities lead left the project team because of other higher priority projects that were ongoing; this departure did not affect project progress.
- March 2008: The project team requested that the first oil date be extended to August 2008. It was realised that the mandated July 2008 date was not practical.
- May 2008: The project team requested another extension of the first oil date to November 2008.
- During the drilling campaign, several operation issues were encountered:
  - Water was found instead of the expected hydrocarbon in reservoir C, a section called C2C. The team had limited data in this C sand. The A1 well (the first well) had penetrated the C sand and identified that the fault was not a "leak" fault but rather a "seal" fault. Prior to drilling, the team had assumed a "leak" fault and the simulations were based on this assumption.

– The A9 well (appraisal well and the second well drilled) encountered casing setting problems at the 18⅝" section. The team then cleaned out the hole and the well was unintentionally sidetracked. Therefore, the well was called J4-A9 ST1. Then, this well experienced lost circulation and the drill pipe got stuck. The team had to cut the drill pipe and lost the bottomhole assembly (BHA); the well is now suspended. The team plans to use slot 6 to target the same sands as the A9 well; the well is now called A5.

– The A6 well was originally a dual-string completion design but became a single-string completion because of the optimisation study. Based on the previous wells' experience, the team is using a rhino reamer instead of the conventional reamer to clean out the hole.

  Moreover, based on the previous well experience, the team changed the 22" hole size to a 24" hole size because the 18⅝" casing was difficult to set. The original design was to enable the team to save on cement cost. However, the design caused problems, so the casing designs had to be changed. An additional cost of US$2.5 million was incurred for each of the five wells that required this casing design change.

  After the correlation run, the team discovered that the well came in 39 ft short of the intended target depth. Therefore only the A sand was produced. The team had missed the B sand target.

- First oil achieved on 13 October 2008.

- After the second well was drilled, the project team has downgraded the recoverable resources to 12 MMBOE because of various drilling issues and incorrect subsurface assumptions stated above. This is a recoverable volume downgrade of 9 percent from the sanctioned estimate (refer to Table 6).

Table 6
Recoverable Resource Promise for J4 Development Project

	Project Sanction	After Optimisation Study (May 2008)	Change After Optimisation Study	After 1st and 2nd Wells (Feb 2009)	Drilling Completed (May 2009)	Change at First Production
Oil (MMstb)	8.6	11.2	30%	8.9	15.6	81%
Gas (bcf)	27.0	19.7	-27%	18.2	29.4	9%
Total (MMBOE)	13.3	14.6	10%	12.0	20.7	56%

- May 2009: The original wells program is completed. The actual drilling cost is US$91 million compared to the cost estimate at sanction of US$78 million.

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. IPA research shows that having an integrated team results in better overall project performance. IPA data overwhelmingly demonstrate that projects with integrated teams require less contingency than projects without integrated teams.

The J4 Development Project team was *Integrated*. The project team was located in Kuala Lumpur, Malaysia, with the various functions in the same building. Although a core team was formed during project definition, this project suffered from turnover in lead roles—project manager, facilities lead, and project controller. However, these turnovers did not significantly affect execution costs or schedule because of the strong core team involved in the project.

Execution and Contracting Strategy

Because the first oil date was required by PMU to prevent a PSC shortfall, the team worked backwards to build a schedule to achieve the first oil date. To accomplish the business objectives, the team had to perform FEL 2, FEL 3, and the FDP development concurrently. The team was relatively small with some members were also engaged in other small projects. The team had 4 months for FEL 2 and FEL 3, and 14 months to execute the project.

The J4 Development Project contracting strategy for the WHP scope relied on an engineer, procure, construct, and commission (EPCC) lump-sum contract to achieve the following objectives:

- Improve the project schedule or meet the project startup
- Minimise PCSB's contractual interfaces
- Secure quality equipment and services at competitive rates while maximising Malaysian participation
- Select safety and environmentally conscious contractors

The team used an existing contract with MJSB for structural steel and pipeline procurement.

The Transportation and Installation (T&I) contract was established under a previous umbrella arrangement with TL Offshore Sdn Bhd (TLO)—this contract is managed by the Petronas construction department. 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 to source the vessels on the requested work schedule as agreed during planning each year. The installation vessels for the WHP and pipelines for the J4 Project were therefore contracted to TLO. The contract price from TLO increased during the execution phase due to a renewal of the umbrella contract. The project team was unaware of the contract expiring and therefore did not adjust the rates in the cost estimate.

As part of the overall government objectives, a Vendor Development Program (VDP) was initiated to improve the manufacturing capabilities in Malaysia. The project was required to use approved vendors in this program. The vendors were chosen based on an open bid tendering process, which screened for technical capabilities and then the lowest bid.

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 project drivers. Table 7 outlines the specific characteristics of this subset.

Table 7
Characteristics of Recent Subset of Upstream Projects

Characteristic	J4 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)	13	2	88	>1,500
Actual Asset Cost (RM MM)	712	<39	865	>16,500
Water Depth (m)	53	1.5	113	> 2,100

WELLS $/BOE DATASET

Table 8 shows the Wells $/BOE dataset, which was used to establish industry benchmarks. The J4 Development Project is well within the characteristics range of this dataset.

Table 8
Characteristics of the Wells $/BOE Dataset

Characteristic	J4 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)	21	2	76	732
Water Depth (m)	53	24	154	2,205

FACILITIES $/BOE DATASET

Table 9 shows the Facilities $/BOE dataset which was used to establish industry benchmarks. The J4 Development Project is well within the characteristics range of this dataset.

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

Characteristic	J4 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)	13	2	64	> 1,000
Water Depth (m)	53	6	111	> 2,000

FACILITIES SCOPE DATASET

Platform Dataset

The J4 Development Project facilities comprise a WHP and intrafield pipeline. The facilities costs were benchmarked using Upstream Cost Engineering Committee (UCEC[26]) metrics because the hydrocarbon throughput for the J4DR-A platform is small relative to the wellhead platforms (WHP) in our 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. UCEC data do not differentiate between a processing platform and a minimal processing platform.

Pipelines Scope

The J4 Development Project's pipeline scope is well within the characteristics range of our standard pipeline model dataset. The cost benchmarks are therefore based on these databases.

Table 10
Characteristics of the Pipelines Dataset

Characteristic	J4 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)	139	3	69	2,119
Pipeline Diameter (in)	10	5.6	11.7	45.8
Pipeline Length (km)	53	1	28.6	658
Water Depth (m)	57 (max)	11.4	90	1,935

[26] 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.

WELL CONSTRUCTION DATABASE

The subsurface and drilling characteristics of the J4 Development Project lie well within the range of our standard subsurface benchmarking databases, so we are readily able to benchmark these elements using our standard analyses.

Table 11
Characteristics of the Well Construction Database

Characteristic	J4 Development Project	Dataset (161 projects)		
		Minimum	Median	Maximum
Year of Sanction	2007	1990	1997	2004
Actual Cost (US$ million)	91	2.3	84	1,590
Region	Malaysia	North America, 30%; Europe, 36%; Africa, 11%; South America, 11%; Oceania, 5%; Asia, 7%		
Water Depth (m)	53	6	140	2,205
Post-Startup Life-of-Project Production Stream (MMBOE)	21	2	67	3,287

PROJECT OUTCOMES

In the following sections, we summarise the estimated and actual outcomes for the J4 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 models compare the project with the industry average capital expenditure per barrel of oil equivalent ($/BOE). The next level looks at 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. 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 drive each other. 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). Lastly, we also look at cost predictability.

Table 12 summarises the estimated and actual costs for the J4 Development Project using the project team's cost breakdown. The estimate for the platform and pipeline was RM337 million, including RM13 million in contingency. The wells campaign was estimated at RM294 million. The total funding available for this project was RM631 million. The final cost for the facilities scope was RM381 million and for the wells campaign is RM331 million.

Table 12
Cost Distribution for the J4 Development Project (RM MM)[27]

Cost Category	Total Project Estimated Cost at Sanction (RM MM)	Total Project Actual Cost (RM MM)
Facilities and Export		
Front-End Engineering	5.8	5.8
Detailed Engineering	12.3	12.3
Project Management	38.9	38.9
Fabrication/Material/Equipment	115.2	114.5
Tow, Integration, Transport, Installation	124.7	181.7
Hook-up and Commissioning	22.1	22.1
Other Project Costs	5.3	5.8
Contingency	12.5	
Total Facilities Costs	**336.7**	**381.1**
Well Construction		
Detailed Well Planning	6.4	10.0
Non-Well Activities	16.3	18.9
Xmas Tree	3.1	Costs were embedded
Drilling	165.4	174.8
Formation Evaluation	9.0	19.8
Completion	23.2	104.3
Other Project Costs	30.5	2.9
Contingency	40.4	
Total Well Program Costs	**294.3**	**330.7**
Total Facilities and Well Program Costs	**631.0**	**711.8**

[27] Total costs may not add up due to rounding.

Benchmark Normalisation

IPA cost adjusting 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.

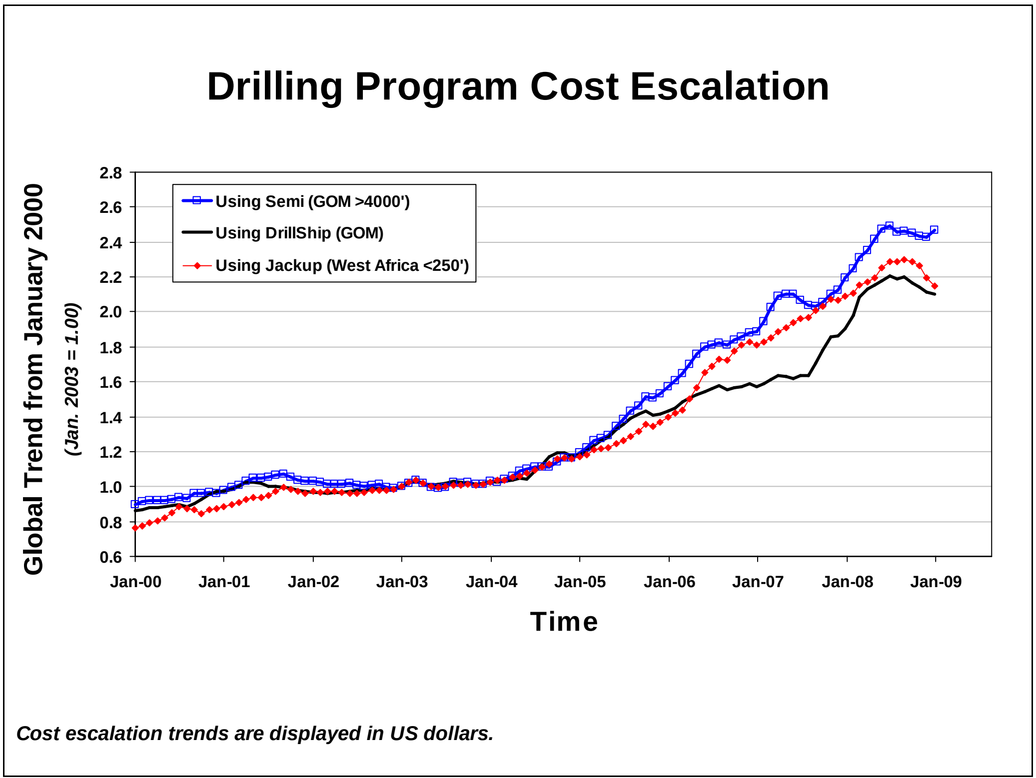

Figure 2

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 estimate costs. For the J4 Project, the estimate date was May 2007.

In the case of the lump sum contracts, projects 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 where the amount for the designated scope is not set for the sanctioned estimate. For the J4 Project, the increase in vessel rates from TLO and additional costs for change orders (costs that are above the EPCC lump sum contract cost) in the facilities scope, will therefore, be adjusted.

Capital Cost per Barrel

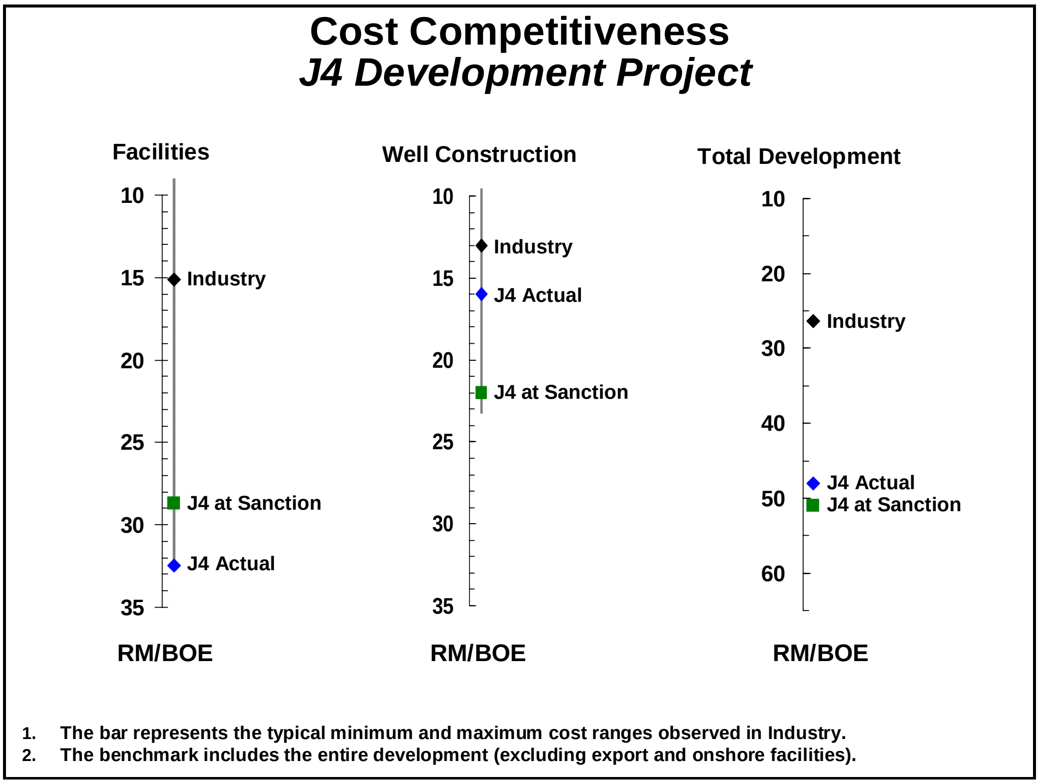

Figure 3

To assess the development costs, we compare the project's cost per barrel with that of other similar-size 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 J4 Development Project $/BOE metric with metrics for projects with comparable resource promise (21 MMBOE) at similar water depths (53 m). The project is an expensive development for its anticipated production stream. The higher than industry-average asset $/BOE is driven by the expensive wells and facilities RM/BOE of approximately 16 and 32, respectively; the industry-average RM/BOE is 13 for wells and 15 for facilities.

The high wells BOE cost is largely driven by the lower than industry-average[28] recovery per well and the high reservoir complexity. The industry-average recovery per oil wells is 4 million BOE per well; the J4 field has a recovery of 3 million BOE per well. As explained later in the report, the chosen concept for the J4 field was poorly developed, which drove the unattractive development cost per barrel of oil.

The facilities BOE cost is also expensive. The high facilities BOE suggests either that the concept selection could have been better or that this is an expensive field to develop.

[28] Based on 22 projects of similar-size resource promise and water depth.

Total Wells Concept Cost

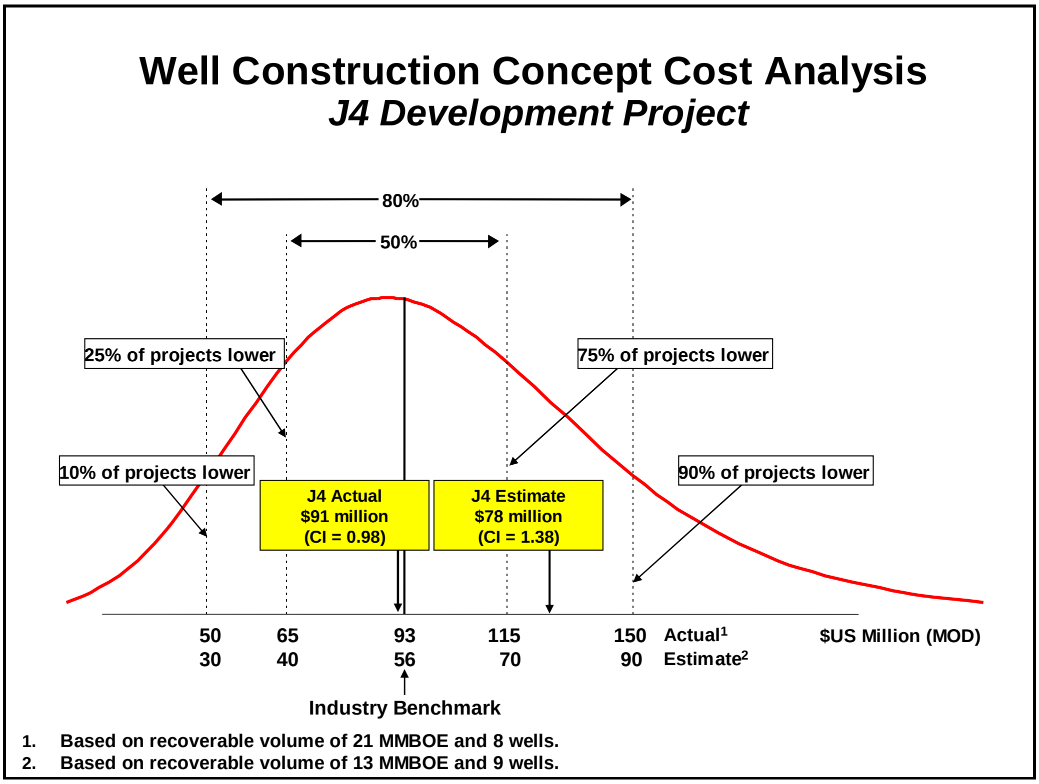

Figure 4

Figure 4 illustrates the concept cost benchmark[29] for the well construction program of the J4 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 J4 Development Project is $93 million (or RM339 million)[30]. The project team's estimate of $78 million (or RM295 million) is 38 percent more expensive than the industry average of $56 million (or RM212 million)[31]. The actual drilling program cost is $91 million (or RM331 million), which is similar to that of the industry average. As explained previously, the recovery per well for the J4 field is lower than industry average, which indicates that the wells concept for this field is not competitive.

[29] Refer to Appendix G for a more detailed explanation of the Well Construction Concept Cost Metric.
[30] Based on 21 MMBOE.
[31] Based on 13 MMBOE.

Total Wells Component Cost

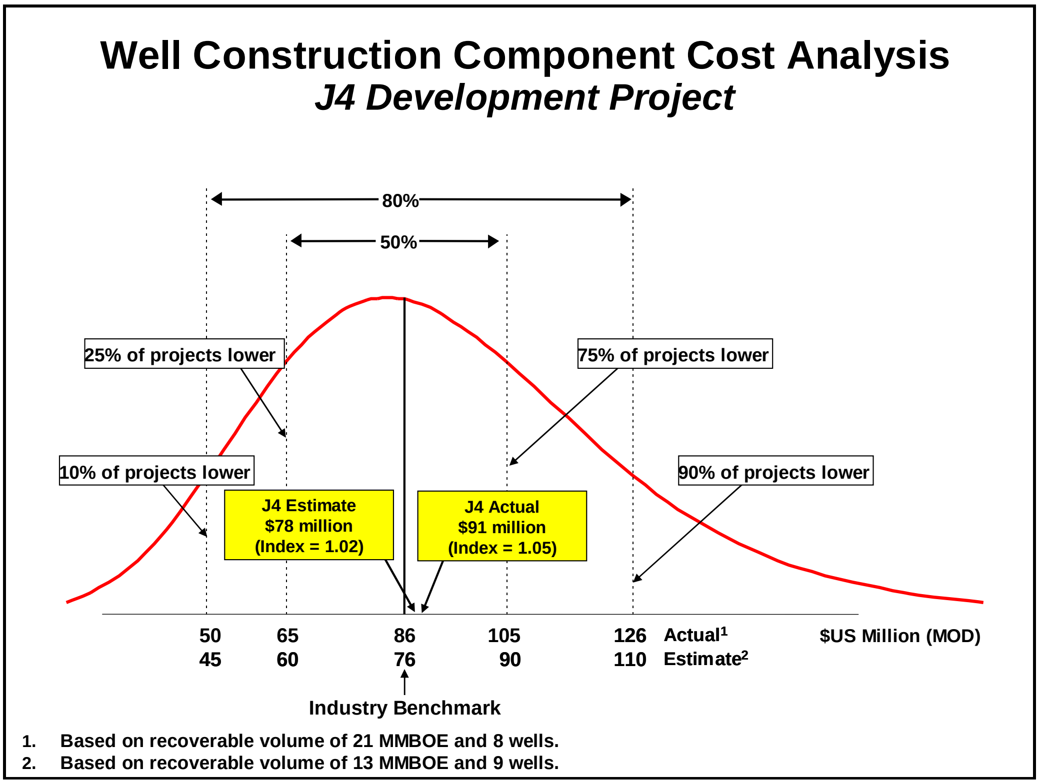

Figure 5

Figure 5 illustrates the component cost analysis[32] for the wells program of the J4 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 was $78 million (or RM297 million), which is nearly the industry average (based on the estimated scenario) of $76 million (or RM290 million). The actual drilling program cost of $91 million (or RM331 million) is within 5 percent of the industry average for the actual scenario. In other words, the J4 Development Project well costs are slightly more expensive on a per well basis than Industry of similar well complexity.

Wells Construction Cost Summary

As illustrated in the above analysis, the actual wells program cost at the component level (or execution level) is nearly industry average. Similarly, the concept for this field and reservoir complexity is industry average as indicated by the cost index of 0.98. However, the recovery per well for the J4 field is significantly lower than other projects with similar size recoverable volumes and reservoir complexity. In other words, the depletion plan was not effectively developed which could be the resultant of an aggressive schedule and lack of basic subsurface

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

data. Therefore the concept significantly drove the Wells $/BOE index to 1.19 which indicates that the industry would typically pay less to develop similar size reservoirs as the J4 field.

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, and if the WHP is manned. UCEC data do not differentiate between a processing platform and a minimal processing platform.

Table 13 summarises the comparison between the J4DR-A platform and UCEC data. The relative UCEC charts are attached to Appendix A.

Table 13
J4DR-A Platform Comparison with UCEC Data

Platform	J4DR-A	UCEC	Index
Jacket Weight (mt) **For given Topside weight (933 mt) and water depth (53 m)**	1,405	902	
Actual Jacket Cost (RM^{MOD} million) **For given Jacket weight (1,405 mt)**	43	55	0.77
Actual Topside Cost RM^{MOD} million) **For given Topside weight (933 mt)**	200	135	1.48
Actual Total Cost (RM^{MOD} million)	243	190	1.28

The comparison tables indicate that the jacket weight was heavier than other platforms in Asia for its topside weight and water depth. For the given jacket weight, the J4 Development Project team was paying less for the structure. On the other hand, when comparing the given topside weight against other projects in Asia, the J4 topside is more expensive. Overall, the J4DR-A platform cost was 28 percent more costly than other Asia projects.

Table 14
Gap Analysis on Component Cost for J4 Development Project

Component Costs Category	J4 Development Project (Percent of TIC)	Comparison Dataset (Percent of TIC)
Transport and Installation	24	15
Hook-up & Commissioning	7	3

Table 14 shows that the Transportation and Installation costs and HUC cost as a percentage of the total installed cost (TIC) for the J4 platform are slightly higher than the comparison dataset, which highlights the costs from the project’s delay in the installation vessel.

The purpose of the gap analysis is to understand the cost breakdown relative to other similar WHP projects and should not be used as a cost benchmark. The comparison dataset comprises of 35 completed WHPs with similar jacket and topside dry weight as the J4 platform. Note that the sum of the component percentages for the comparison dataset will not be equal to 100 percent. This is because some projects in the dataset have incomplete data.

Pipeline Cost

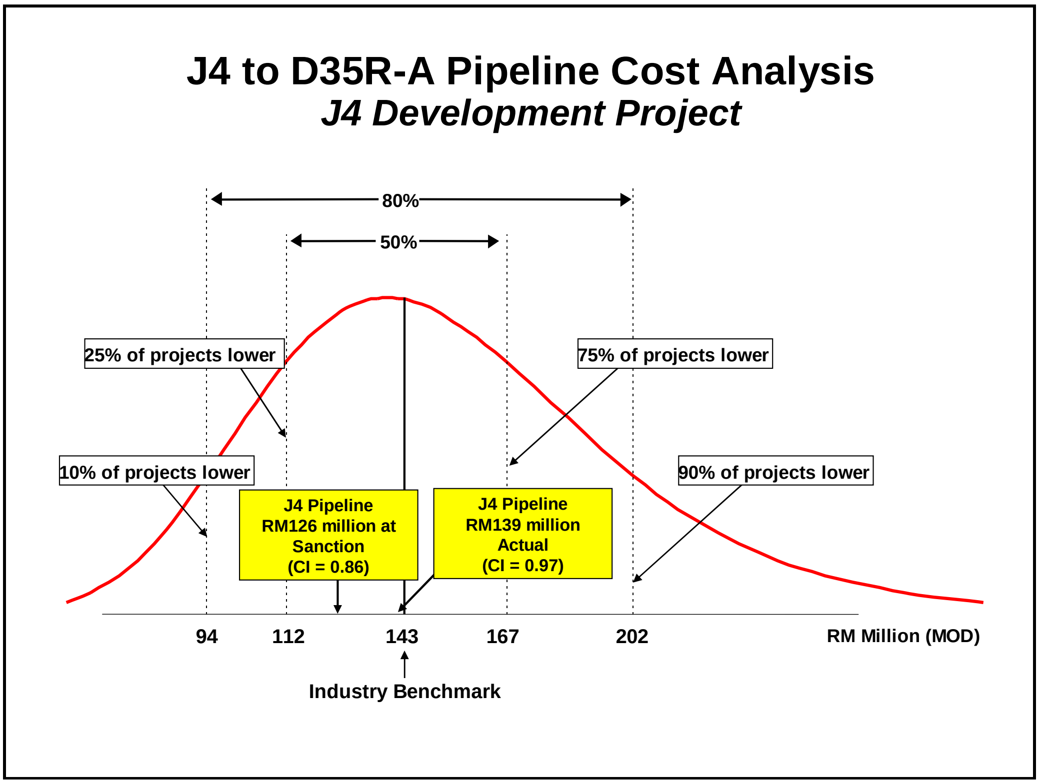


Figure 6

As shown in Figure 6, the average cost to install an intrafield pipeline of similar functionality to the J4 Development pipeline is RM143 million. The project team's estimate of RM126 million was 14 percent cheaper than industry average. The actual cost of the pipeline was RM139 million, which is 3 percent less expensive than Industry. The increase in cost was mainly attributed to the increase in installation vessel rates after the negotiation of the TLO contract, as mentioned previously.

Facilities Cost Summary

As illustrated in the above analysis and shown in Table 15, the pipeline cost is competitive with Industry at the component level. The platform cost is more expensive than Industry for similar dry weight. Moreover, it has been established that the J4 jacket dry weight is higher than for other jackets in the Asian region for a given topside dry weight and water depth. Based on a cost per tonne ratio, the J4DR-A topside is more expensive than other platforms in the Asian region. The jacket cost per tonne, on the other hand, is less expensive than other platforms in the Asian region for similar jacket weights. Overall, the J4DR-A platform is expensive. The Facilities $/BOE index of RM 32 million per BOE is significantly more expensive than the industry average. Therefore, the chosen concept may not be suitable for the relatively small resource promise of 13 MMBOE, which is consistent with the observation that the jacket weights are relatively high, or the resource may simply be relatively expensive to exploit.

Table 15
J4 Development Facilities Cost Summary

	Estimate	Actual	Industry
Total Facilities in RM million (Weighted Cost Index)	337 (1.02)	382 (1.16)	330 (1.00)
– **J4DR-A WHP Platform in RM million (Cost Index)**	214 (1.13)	243 (1.28)	190 (1.00)
– **Pipeline in RM million (Cost Index)**	123 (0.86)	139 (0.97)	140 (1.00)

Cost Deviation

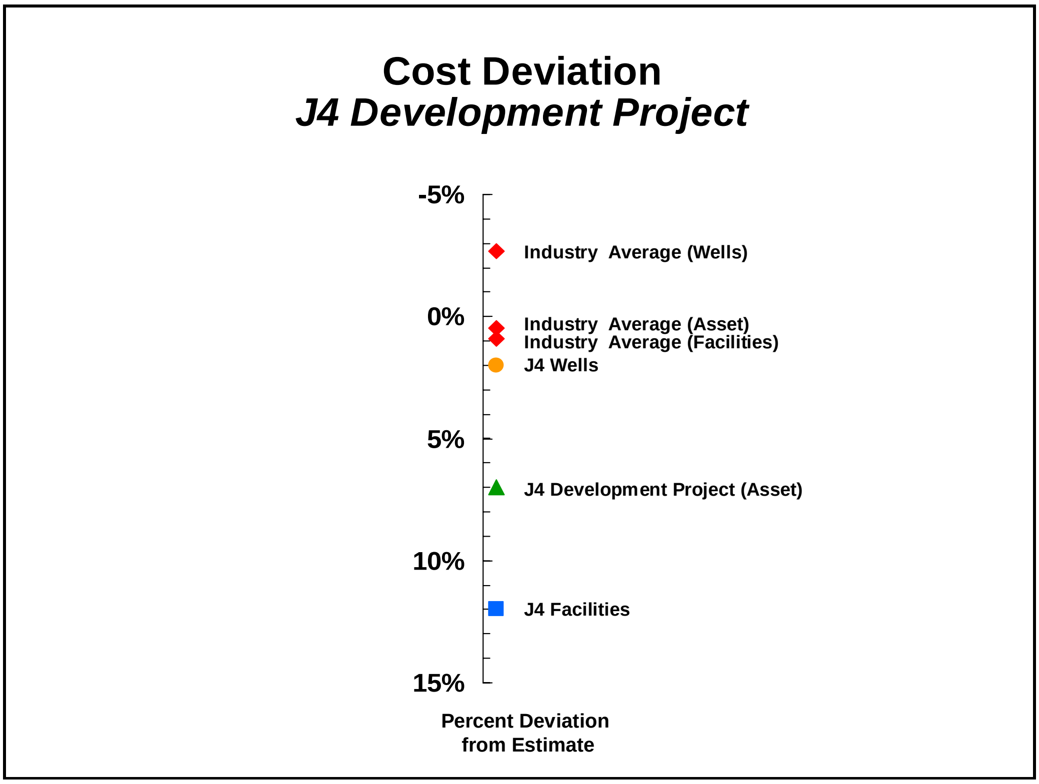


Figure 7

The actual cost of the J4 Development Project facilities was RM381 million; the estimated cost was RM337 million. The facilities cost deviation was therefore 12 percent, as shown in Figure 7. Historically, Industry has deviated from its facilities cost estimate by an average of 1 percent.

The approved EPCC contract, used in the authorisation cost estimate, was RM132 million, which was reduced at the contract award to RM128 million. After more negotiations, the contract price was decreased further to RM122 million. To be consistent, the approved contract price of RM132 million was used as the facilities cost estimate.

Table 16
Cost Deviation Normalisation to May 2007 for the J4 Development Project

	Estimate in May 2007		Actual in MOD	Actual Adjusted to May 2007	Cost Deviation at Estimate Date
	(RM Million)	(US$ Million)	(RM Million)	(US$ Million)	(21 May 2007)
J4DP-A	214	63	243	68	8%
Pipeline	122	36	139	43	19%
Total Facilities	337	99	381	111	12%
Drilling	294	77	331	78	2%
Asset	631	176	779	191	7%

At completion of the facilities scope, the actual cost of the EPCC portion was RM128 million plus significant changes of approximately 5 percent. These changes were driven by standby charges from offshore crew while waiting for SIMOPs from drilling, host tie, and commissioning work. Moreover, T&I costs grew by 46 percent (absolute) after TLO negotiated a new contract with increased rates. Overall the facilities cost deviation was 12 percent, as shown in Table 16.

The wells program (based on seven completed wells) had a cost growth of 2 percent. Historically, Industry has deviated from its wells cost estimate by an average of -3 percent. The original drilling scope called for nine wells to recover 13 MMBOE. After an optimisation study, which was conducted post sanction, the drilling campaign only required seven wells. The original single-string completion has been changed to dual-string completions. The team also made changes to the casing designs, which incurred an extra US$2.5 million per well for 5 wells. The team had originally planned on saving cementing costs, but the design was later found to be inadequate and the team had issues with running in subsequent casing strings.

SCHEDULE

Table 17 summarises the J4 Development Project schedule. The planned execution schedule was 14 months; the actual schedule was 17 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 cycle time for this project (determined from the start of the Define phase to first hydrocarbon) was 27 months. To meet the gas shortfall, the team was required to deliver first oil by July 2008. The project team achieved first oil in October 2008.

Table 17
Schedule for the J4 Development Project

	Plan			Actual		
Project Phase	**Start**	**Finish**	**Months**	**Start**	**Finish**	**Months**
Concept Stage (FEL 2)	7-Apr-06	10-Jun-06	2.1	7-Apr-06	10-Jun-06	2.1
Define Stage (FEL 3)	10-Jun-06	23-Aug-06	2.4	10-Jun-06	23-Aug-06	2.4
Bid Evaluation	15-Dec-06	21-Mar-07	3.2	15-Dec-06	21-Mar-07	3.2
Sanction	21-Mar-07			21-Mar-07		
FDP Approval	9-Apr-07			9-Apr-07		
Detailed Engineering	14-May-07	14-Sep-07	4.0	14-May-07	14-Sep-07	4.0
Procurement	10-Jul-07	9-Apr-08	9.0	10-Jul-07	30-Apr-08	9.7
Fabrication and Construction	1-Sep-07	3-May-08	8.1	1-Sep-07	21-May-08	8.7
Transportation	26-Apr-08	1-May-08	0.2	14-Jun-08	24-Jun-08	0.3
Installation	2-May-08	12-May-08	0.3	24-Jun-08	16-Jul-08	0.7
Hook-Up and Commissioning	13-May-08	16-Jun-08	1.1	11-Sep-08	19-Oct-08	1.3
Development Drilling	13-May-08	25-Oct-08	5.4	26-Jul-08	24-May-09	9.9
First Production	1-Jul-08			13-Oct-08		
Execution Schedule	14-May-07	1-Jul-08	13.6	14-May-07	13-Oct-08	17.0
Cycle Time	7-Apr-06	1-Jul-08	26.8	7-Apr-06	13-Oct-08	30.2

Facilities Execution Schedule

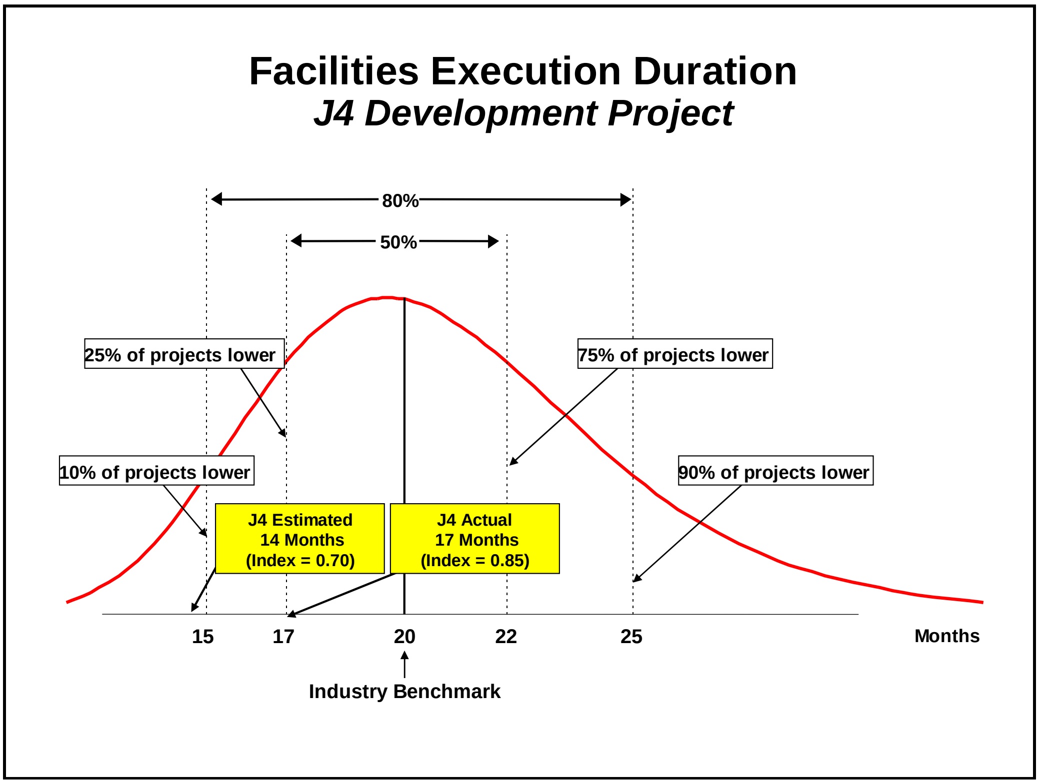


Figure 8

As shown in Figure 8, the planned execution duration of the J4 Development Project was 14 months, which is much faster than the industry average of 20 months. The actual time needed to execute the J4 Development Project was 17 months, still 15 percent faster than Industry. The routine technology, strong core project team, good project definition, and adequate project controls were key factors that enabled the achievement of such a fast schedule.

Well Construction Schedule

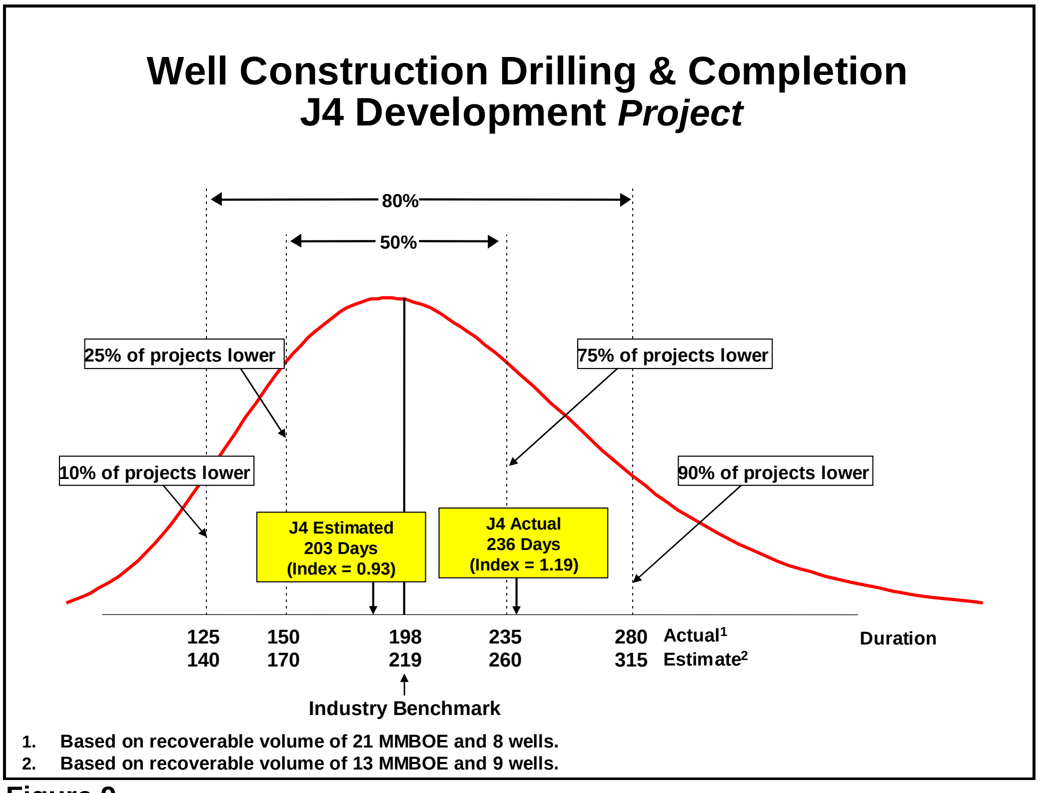


Figure 9

As shown in Figure 9, the planned well construction drilling and completion duration of the J4 Development Project is 203 days, which is slightly faster than the industry average of 219 days. The actual duration of the drilling campaign for eight wells is 236 days, which is approximately 19 percent slower than Industry. The planned duration per well was approximately 23 days, but the drilling team had encountered problems with casing setting and lost circulation, which extended the duration per well to approximately 30 days.

Schedule Deviation

The J4 Development Project overran its planned execution schedule by 21 percent. The J4 Development Project is less predictable than the average industry project, which overruns its planned schedule by 4 percent. PCSB's average schedule deviation is 12 percent. This percentage is calculated by dividing the actual execution duration by the planned execution duration. The planned schedule was considered aggressive by the team, and was extremely aggressive based on the schedule benchmark. Therefore, the team faced a high risk of schedule slip. The main driver of slip was the late arrival of the installation vessel and drilling rig. Moreover, procurement took longer than expected.

PROJECT PRODUCTION STREAM AND OPERABILITY

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.

At sanction, the recoverable resource promise was expected to be 13 MMBOE. After the second well, the estimated recoverable resource promise has been downgraded to 12 MMBOE based on the first and second wells data. As mentioned previously, the project team found water in the C2C sand, which was not expected during subsurface definition. Moreover, the team had assumed a leak fault in the C block rather than a seal fault. This is an estimated downgrade of 9 percent in the total resource promise. However, after the drilling campaign was completed (based on the seven wells), the recoverable volumes had increased by 56 percent to 21 MMBOE. The increase in the recoverable volume was because the subsurface team had planned to produce from three reservoirs but instead the field is now producing from five reservoirs.

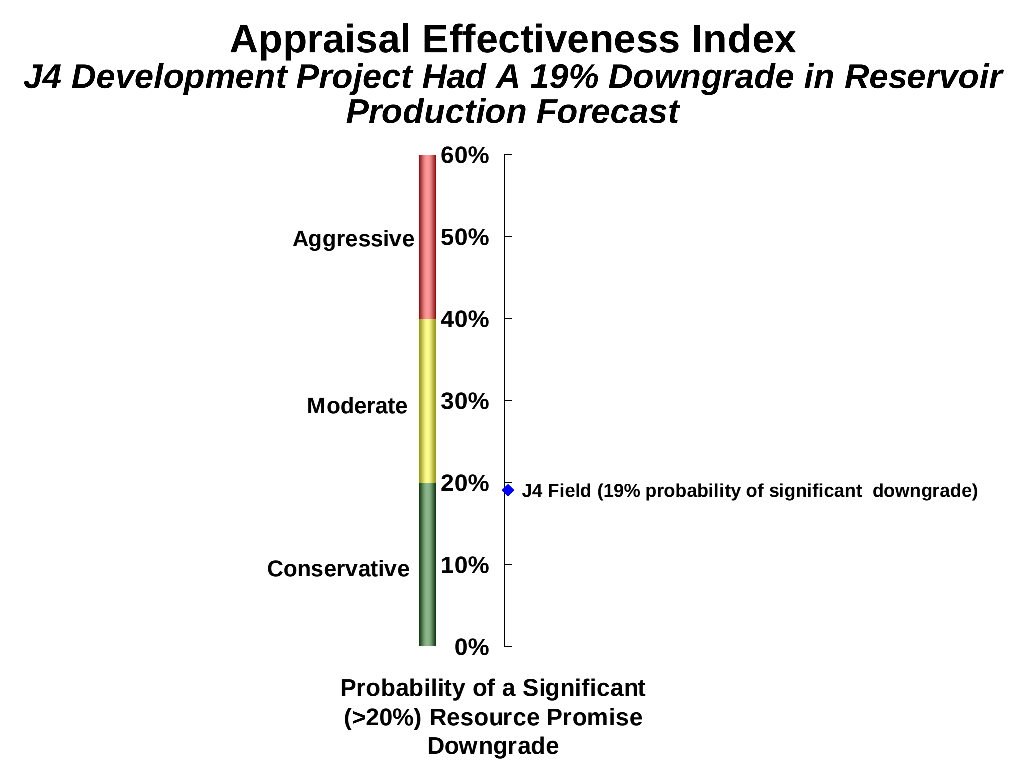


Figure 10

Shown in Figure 10, IPA’s Appraisal Effectiveness Index (AEI) indicated a low probability of a reservoir production downgrade of more than 20 percent. 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 20 percent downgrade in reservoir production forecast. For the J4 field, there was a 19 percent probability of a downgrade of at least 20 percent, based on the subsurface efforts.

Operability/Production Attainment

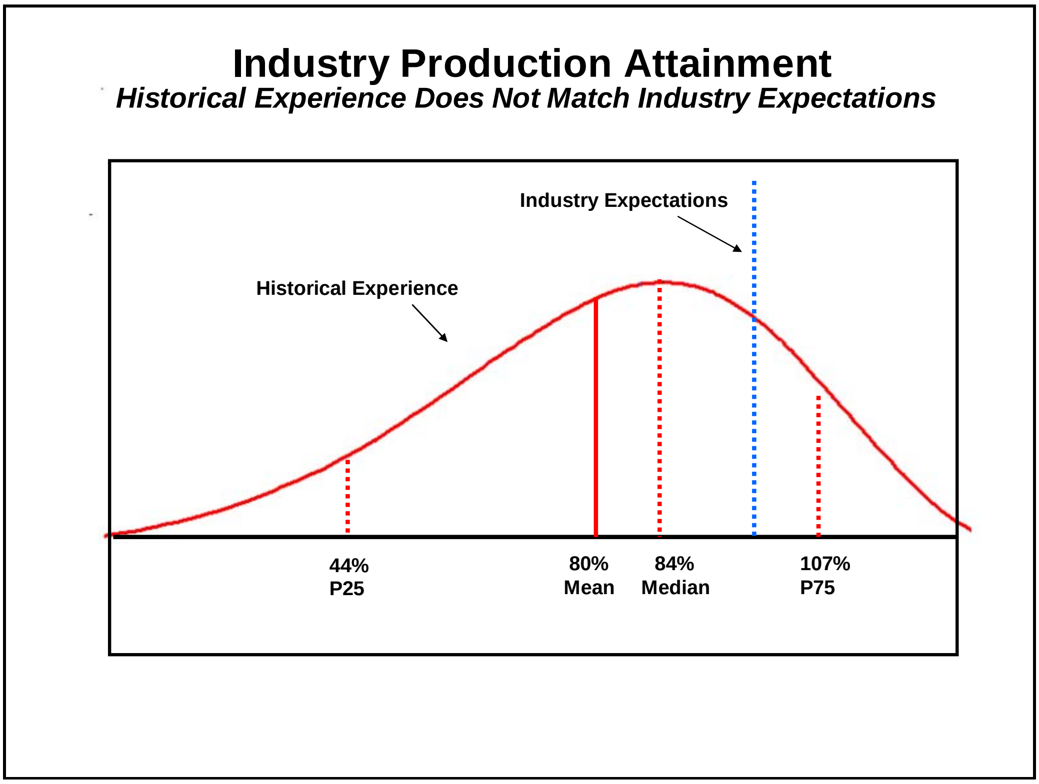


Figure 11

As a tangible proxy for field performance, IPA assesses ***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.

For the J4 Development Project, it is too early to determine the operability outcomes, but the team expects to be able to export oil continuously and to have the system fully operational by mid 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 J4 Development Project had a *Moderate* appraisal philosophy that was conducted by Shell. The data were handed over to PCSB after the field lease expired. 3D seismic was used to underpin the reservoirs, but the seismic was shot over 20 years ago, processed in 1985 and reprocessed in 1992 by PCSB. The seismic image was clear, but no velocity data were available from Shell to provide inversion analysis. An exploration well and four appraisal wells were drilled and completed in J4. Log data were available for each well and core samples were taken from four wells. Pressure and fluid samples were also taken in the J4 field. Production data were also available through DSTs on two wells, which were tested for about 24 hours each. Therefore, given the small field, appropriate number of wells penetrated, and subsurface data available, the J4 Development Project is classified as having a *Moderate* appraisal strategy.

SUBSURFACE COMPLEXITY

Reservoir Complexity and *Wells Complexity* are two metrics that IPA uses 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 J4 Development Project.

Reservoir Complexity

The Reservoir Complexity Index (RCI) for the J4 reservoirs is 45, which is also more complex than the average PCSB RCI of 37; the industry-average RCI is 39. The J4 reservoirs are highly stacked and compartmentalised, with two dominant orientations with faults exhibiting both dip and strike-slip movement. The reservoirs show no compaction drive, minimal aquifer support, and little reservoir energy.

Well Complexity

The production wells are less complex than the industry and PCSB averages. The J4 wells consist of six production wells and one appraisal well. The well complexity index (WCI) for these wells range from 41 to 51; industry average is 52 and the PCSB average is 49. The team had to design the wells to incorporate possible shallow hazards and adverse gases, and tectonic stresses. The completion designs include gas lift and sand controls. The original well designs were for single-string completions. However, after sanction, the well number changed from 9 to 7 with 11 completion strings.

FRONT-END LOADING

Front-End Loading (FEL) is a measure of the level of definition of a project; FEL provides a picture of the project's readiness for execution and level of risk. FEL 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

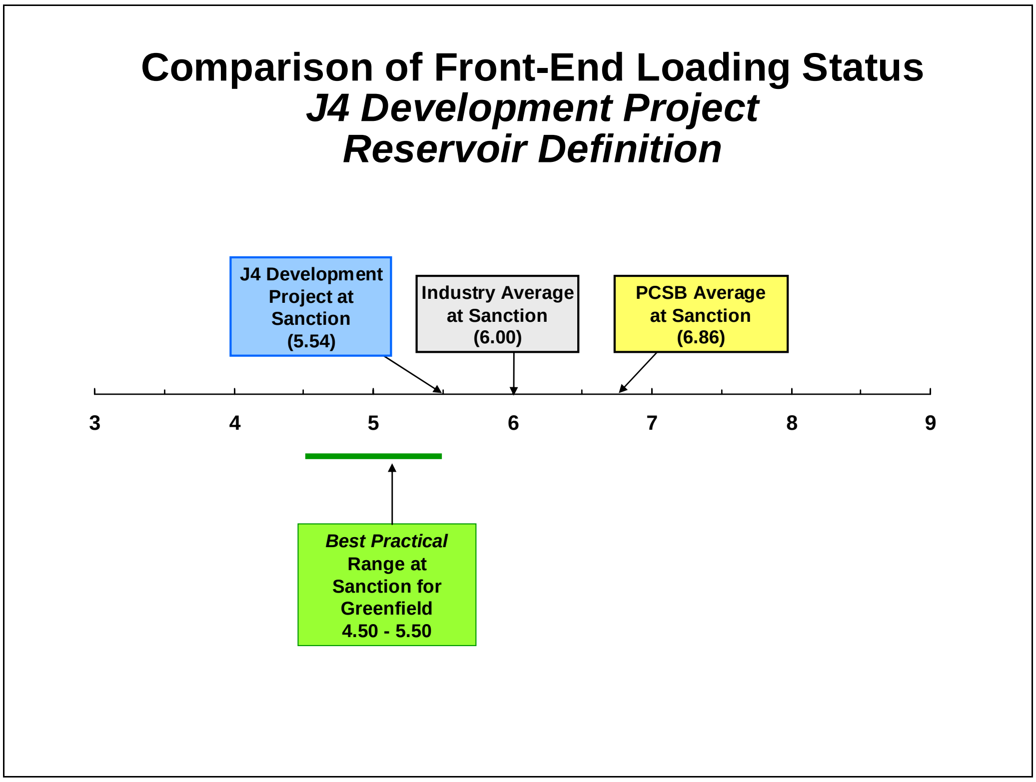


Figure 12

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 12 illustrates the Reservoir FEL Index for the J4 Development Project. The Reservoir FEL Index was 5.54, which falls outside the *Best Practical* range of 4.50 to 5.50 for greenfield developments at sanction. The average for PCSB projects at sanction is 6.45.

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 components of the Reservoir FEL Index in Table 18.

Table 18
J4 Development Project Reservoir Front-End Loading (at Sanction)

FEL Component	**J4 Development Project**		***Best Practical* for Greenfield Developments**	
Inputs	*Preliminary*	*(2)*	*Definitive*	*(1)*
Constraints	*Preliminary*	*(2)*	*Preliminary*	*(2)*
Tasks	*Preliminary*	*(2)*	*Definitive*	*(1)*
Planning (overall)	*Definitive*	*(1)*	*Definitive*	*(1)*
Reservoir FEL	5.54		4.50 to 5.50	

Inputs

Inputs were *Preliminary*, which lags the *Best Practical* level for greenfield developments. The subsurface team had sufficient logs and analogue data, 3D seismic data, and fluid and pressure information to develop geologic and reservoir simulation models for the J4 field. As mentioned in the Appraisal section, the team was provided the appraisal data from Shell after the field was handed over to PCSB. The team indicated that not all information could be obtained to conduct a thorough subsurface evaluation (especially fluid data from all compartments). However, the data provided were enough to perform the necessary simulations, analysis, and interpretations. The team plans to have an appraisal well in the adjacent block as per PMU's request.

Constraints

Constraints were *Preliminary*, which is *Best Practical* at sanction. The single major constraint was the timing the team had to conduct the subsurface evaluation. The forecast PSC shortage meant that PCSB was required to develop the J4 field shortly after the handover from Shell. Therefore a first oil deadline by July 2008 was created. Given this deadline, the project team had little time to adequately complete subsurface activities. Consequently, the FDP was not completed in time for approval by the Petronas board, and was instead conditionally approved. The subsurface work had to be done in parallel with the facilities and wells scope, which resulted in late changes.

Tasks

Tasks were *Preliminary*, which lags behind *Best Practical* at sanction. The team performed 3D static and dynamic modelling and PVT analysis. Fluid characterisation was understood by the team and documented in the FDP. Reservoir compartments could not be defined, and only major boundaries were mapped. Development drilling scope was prepared, and an optimisation study was ongoing at sanction.

Planning

Reservoir Execution Planning was *Definitive*, which is *Best Practical* at sanction. However, the subsurface lead turned over twice during FDP with transfers to another project. The subsurface team developed a high-level schedule of activities. The data acquisition plan was developed, and the FDP was conditionally approved.

Well Construction Front-End Loading

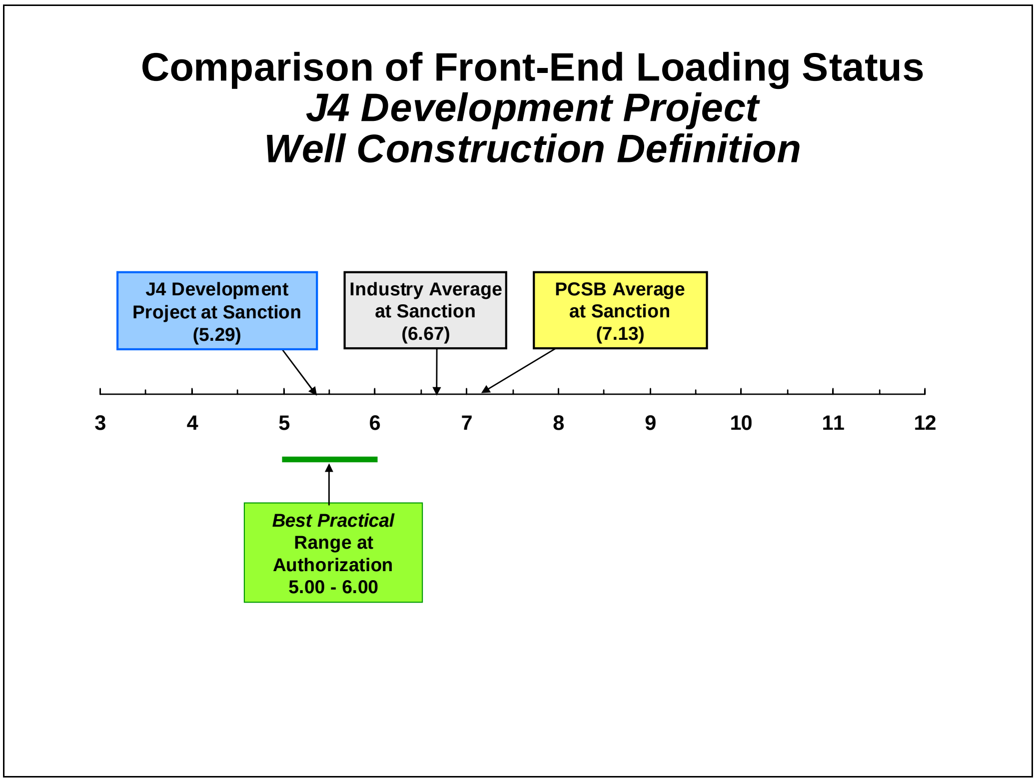


Figure 13

As shown in Figure 13, the J4 Development Project's Well Construction FEL Index was 5.29, which is in the *Best Practical* range for projects at sanction. 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 of components of the Well Construction FEL Index in Table 19.

Table 19
J4 Development Project Well Construction Front-End Loading (at Sanction)

FEL Component	J4 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	*Preliminary*	*(2)*	*Preliminary*	*(2)*
Wells FEL	5.29		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 well objectives and scope were defined. Based on the results of an ongoing optimisation study from subsurface at sanction, the well number was subject to change. The team did not have the geological data from Shell in the overburden section. Therefore, shallow gas at the overburden was not fully understood. However, the team designed the wells to incorporate possible shallow gas and hazards.

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 not developed at sanction. However, as the team had experience in this region, this FEL component was viewed as low risk.

Well Engineering Status

The Well Engineering Status was *Preliminary*, which is *Best Practical* at sanction. Preliminary well designs were developed because of an ongoing optimisation study at sanction. Changes to well numbers and completion designs occurred due to this study. The team identified the long-lead items, but did not place orders at sanction. Wellhead equipment was agreed and approved by management. The casing and mud program was finalised.

Well Planning

Well Planning was *Preliminary*, which is *Best Practical* at sanction. A young core team had been assembled. At the time, the engineers were working on multiple small projects and were overloaded with work. The contracting strategy was finalised: third-party services were rolled over from existing long-term contracts. Rig candidates had been identified and the GSF 134 was selected because of its reach capability to each slot. However, during execution, the rig was given to another project. The team was able to negotiate back the rig in time for drilling. A preliminary cost estimate was prepared; individual AFEs were prepared after project sanction.

Facilities Front-End Loading

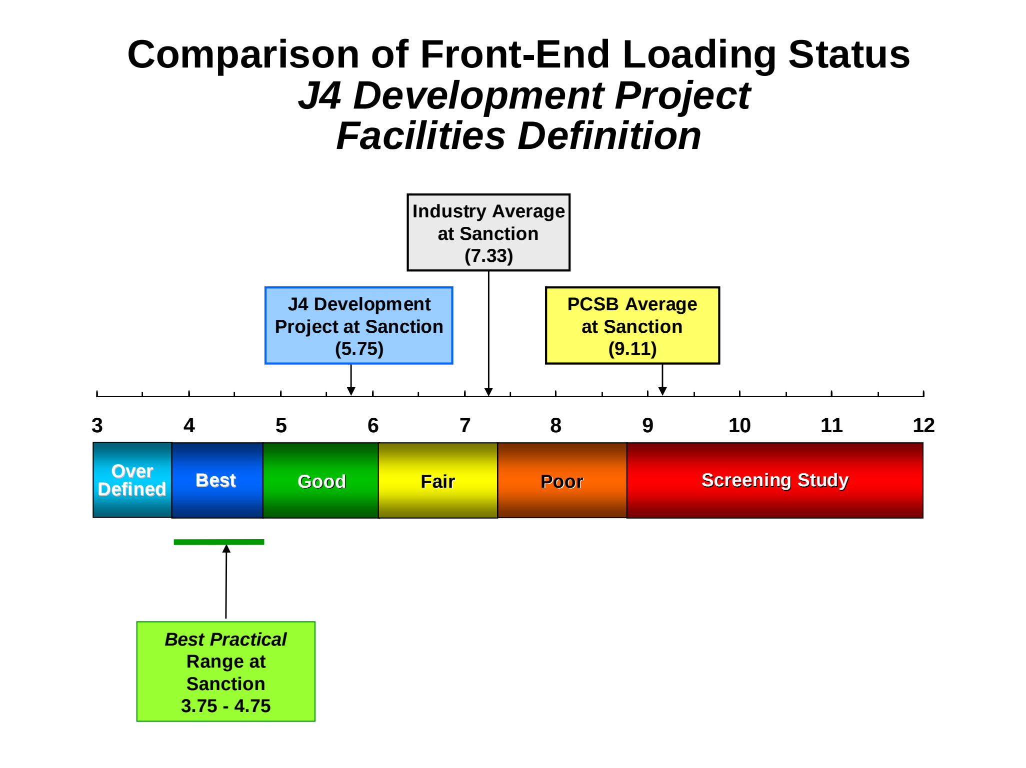


Figure 14

Figure 14 illustrates the FEL Index for the J4 Development Project facilities. The project has an FEL Index of 5.74, which is a *Good* rating. Although better than the industry average (FEL Index of 7.33), it trails the *Best Practical* range (3.75 to 4.75) at sanction. The J4 Development Project's definition was better than the PCSB average FEL index, which is 9.11 (*Screening*).[33]

The four components of Facilities FEL are (1) Fluid Characterisation and Volumes, (2) Project-Specific Factors, (3) Engineering Status, and (4) Project Execution Planning. We provide ratings for each of components of the Facilities FEL Index in Table 20.

Table 20
J4 Development Project Facilities Front-End Loading (at Sanction)

FEL Component	J4 Development Project		*Best Practical*	
Project-Specific Factors	*Preliminary*	*(2)*	*Definitive*	*(1)*
Project Execution Planning	*Preliminary*	*(2)*	*Definitive*	*(1)*
Engineering Status	*Advanced Study*	*(2)*	*Advanced Study*	*(2)*
Facilities FEL	5.75 *(Good)*		3.75 to 4.75	

[33] The PCSB projects were based on projects used in the baseline assessment in 2007 and 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 soil borings at the platform location and completed the soil analysis. Regulatory and environmental permits were identified and issued. Local import taxes was understood and incorporated into the cost estimate. Local content requirements were identified but plans were not developed and approved. The fabrication yard availability was known. The team also identified the living quarter requirements for the offshore scope but had not put together a final manpower loading plan to incorporate into the cost estimate and schedule.

Project Execution Planning (Overall)

The Project Execution Planning was *Preliminary*. *Best Practical* for this component at sanction is *Definitive*. Project objectives were defined, and the team and business aligned on these objectives. The on-site team was established to manage and ensure timely completion of Mechanical Completion Date (MCD), but it lacked engineering experience. To offset this inexperience, the team had support from the technical peer reviews and senior company staff. 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 and a contracting strategy was defined – contracts can only be awarded after project sanction.

Engineering Status

The Engineering Status was *Advanced Study*, which is *Best Practical* for this component at sanction. FEED was completed by MMC Corporation Berhad (MMC). Because of the project's time constraint, FEL 2, FEL 3, and FDP were all done in parallel. PCSB management agreed to these parallel activities and understood the related risks. To assist with the schedule pressure, the team used the WHP design from the Angsi Project. The project team used cost estimating software (Questor) as a guide to the cost estimate. Preliminary quotes were obtained for a number of key items. The overall cost estimates were high level and were mostly based on historical data.

PIPELINE FRONT-END LOADING

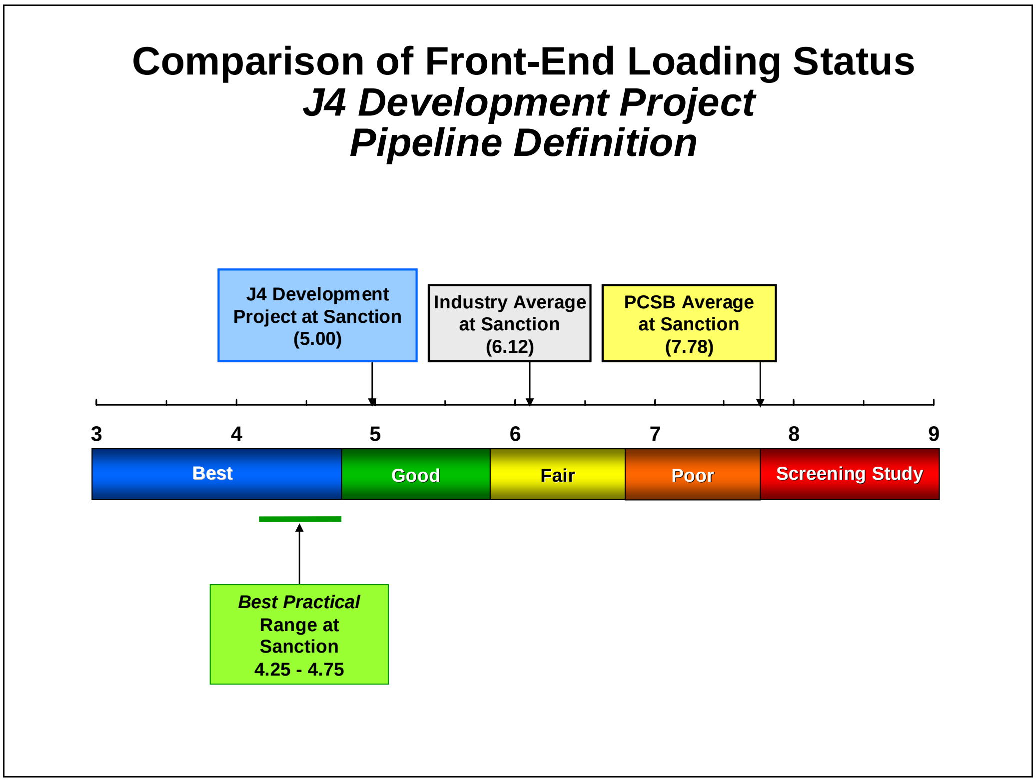


Figure 15

Figure 15 illustrates the Pipeline FEL Index for the J4 Development Project. The Pipeline FEL Index was 5.00 (*Good)*. The *Best Practical* range at sanction is 4.25 to 4.75. We provide ratings for each of components of the Pipeline FEL Index in Table 21.

Table 21
J4 Development Project Pipeline Front-End Loading (at Sanction)

FEL Component	**J4 Development Project**		***Best Practical***	
Site Factors	*Definitive*	(1)	*Preliminary*	(2)
– Route Definition	– *Definitive*		– *Definitive*	
– Seafloor/Terrain Conditions	– *Definitive*		– *Definitive*	
– Right of Way	– *Definitive*		– *Preliminary*	
– Community Issues	– *Definitive*		– *Definitive*	
– Health and Safety	– *Definitive*		– *Definitive*	
– Permitting/Environment	– *Definitive*		– *Preliminary*	
Project Execution Planning	*Preliminary*	(2)	*Definitive*	(1)
Engineering Status	*Advanced Study*	(2)	*Advanced Study*	(2)
Pipeline FEL	5.00 (*Good*)		4.25 to 4.75	

Site Factors

The Site Factors component was *Definitive. Best Practical* at the sanction is *Preliminary*. The pipeline route survey was conducted and soil sampling was taken. The soil samples were analysed and incorporated in the pipeline designs. No community and permitting issues were identified. The J4 field belongs to PCSB as part of the PSC agreement, and therefore the team did not have any issues with right of way.

Project Execution Planning

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

The Engineering Status was *Advanced Study*, which is *Best Practical* at sanction. The pipeline design is conventional and has no new technology. The project team had adequate basic data, such as the temperature and pressure profile of the seafloor, heat and material balances, and seafloor surveys. Based on these basic data, the pipeline was concrete coated for stability and layered with polypropylene to provide the necessary thermal protection. The pipeline design allowed for future intelligent pigging, which will be installed in 5 years by the operations group.

Overall Asset Front-End Loading

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 is 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.

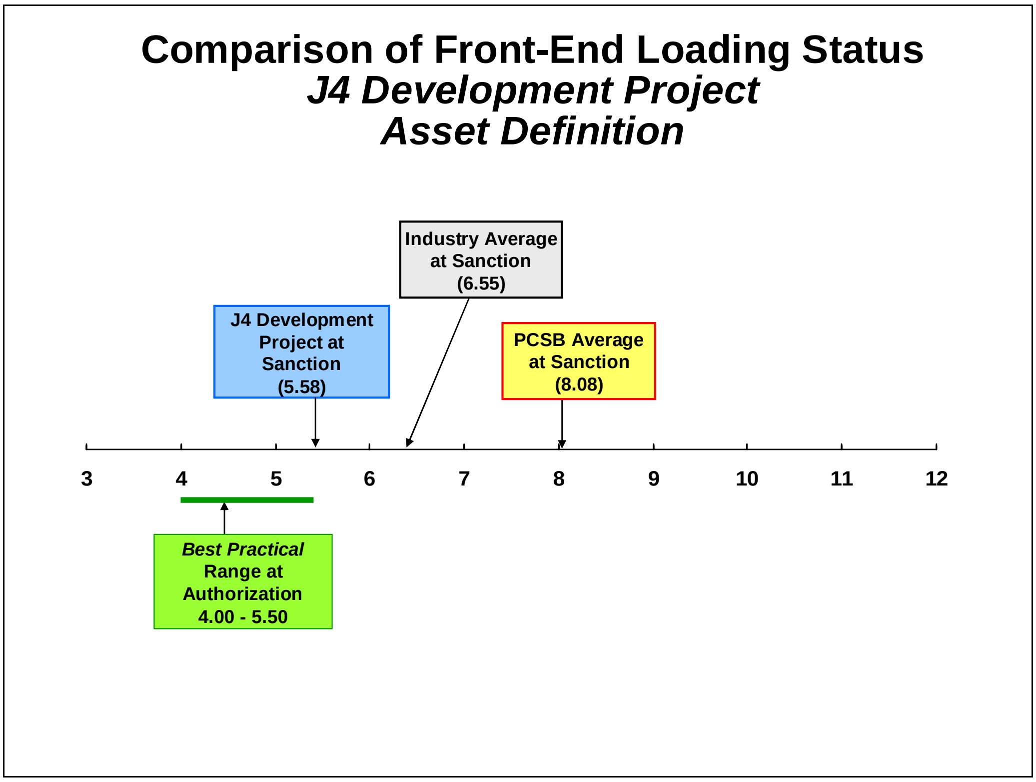


Figure 16

Figure 16 illustrates the Asset FEL Index for the J4 Development Project. The project has an FEL Index of 5.58, which is a *Good* rating. Although better than the industry average, it slightly trails *Best Practical* (4.00 to 5.50) at sanction. Table 22 compares the Asset FEL Index and its components for the J4 Development Project with the *Best Practical* level for a project with similar characteristics.

Table 22
J4 Development Project Asset Front-End Loading Index

FEL Component	Project at Sanction	*Best Practical*	Industry Average
Reservoir FEL	5.29	4.50 to 5.50	6.00
Facilities FEL	5.75	4.25 to 4.75	7.33
Wells FEL	5.29	5.00 to 6.00	6.67
Asset FEL	***5.58***	***4.00 to 5.50***	***6.55***

TEAM DEVELOPMENT INDEX

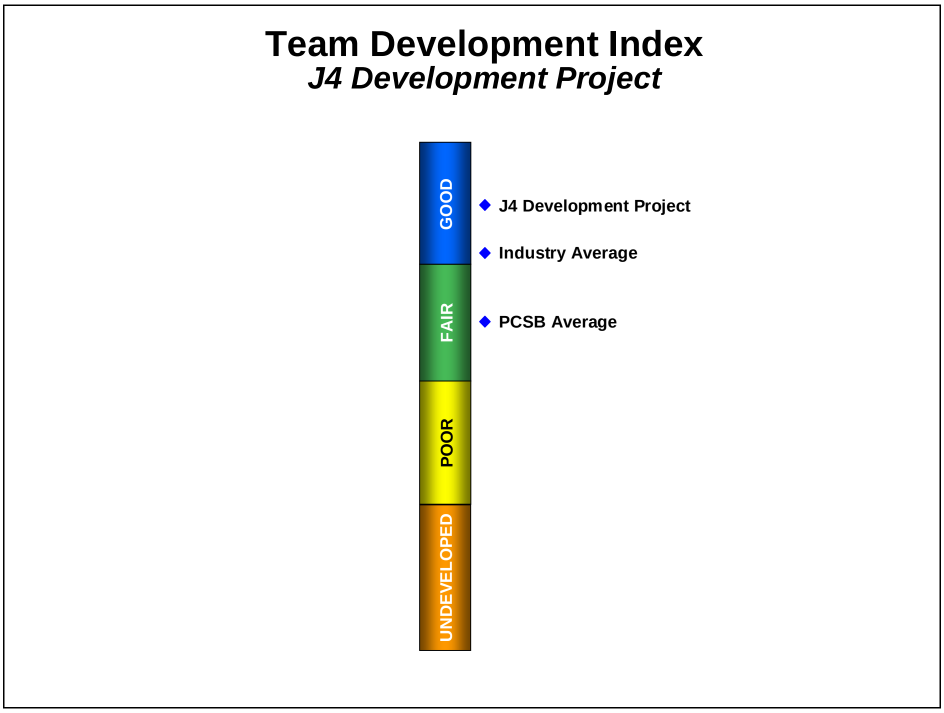


Figure 17

As shown in Figure 17, the J4 Development Project had a Team Development Index (TDI) in the *Good* range, which is better than the industry and PCSB averages. 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, so is provided here 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 J4 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 J4 Development Project, project objectives were aligned with business objectives and 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. For the J4 Development Project key project positions were filled, but had a high turnover rate during execution.
- **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. Risks 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. PCSB Project Management Framework was used, but some steps were bypassed because of the project schedule constraints. The FDP was not completed and was conditionally approved so that the project could continue with the next phase. The team was granted an exception to the process.

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 18 shows that the facilities team used 11 percent of Asset and Facilities VIPs applicable to the J4 Development Project, which is below the industry average of 27 percent of VIPs use during FEL. The project had 9 applicable VIPs and only 3D CAD was used during FEED and detailed engineering. The subsurface team applied 2 out of 6 relevant subsurface VIPs (SSVIPs), or 33 percent. These SSVIPs were Wells Technology Selection and Wells Definition and Design. The team conducted a technology workshop with the subsurface group, drilling group, and the Technical Committee. The result of the workshop included the incorporation of downhole gauges, and surveillance tools. The drilling team conducted a small workshop to discuss the Wells Definition and Design aspects. The discussions included the Classes of Well Quality, Drillability, and Well Simplification.

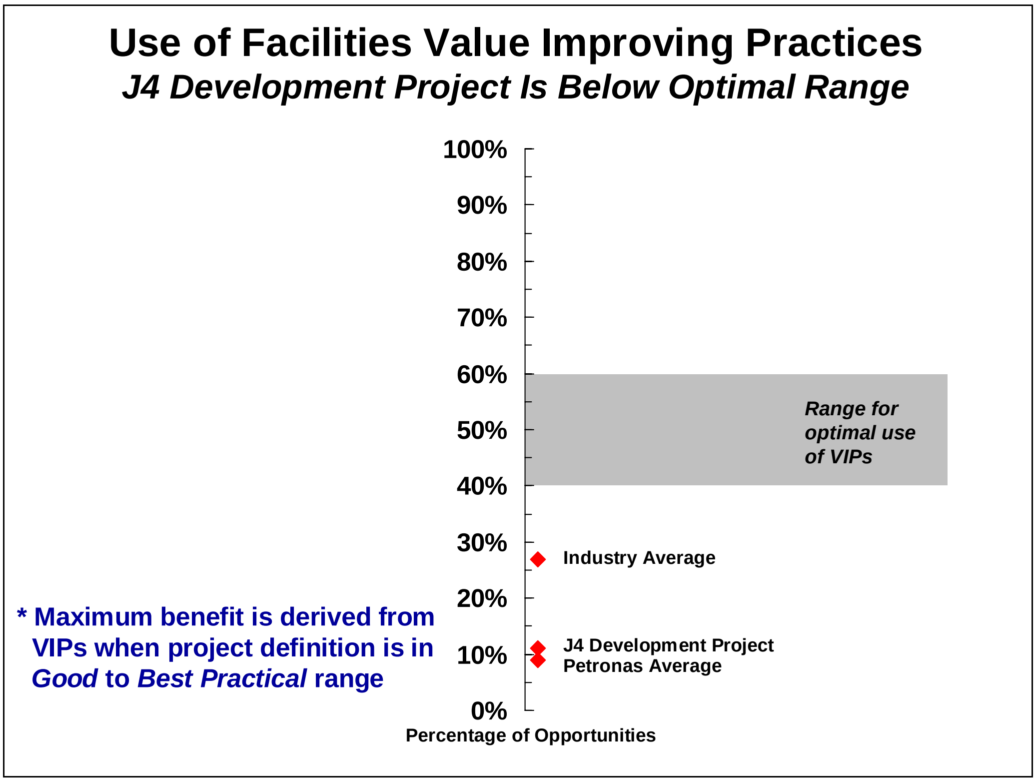


Figure 18

IPA research has shown that the optimal use of Asset and Facilities VIPs is between 40 percent and 60 percent of the applicable VIPs. However, Subsurface VIPs (SSVIPs) have little overlap, and therefore there is no maximum suggested uptake of SSVIPs. For the full definition of each VIPs, refer to Appendix F.

EXECUTION DISCIPLINE

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.

PROJECT CONTROL INDEX

IPA research shows that projects with strong project cost and schedule control practices have less cost growth and schedule slip, and have a lower probability of late changes. During 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.

Project Control Index
PCI for J4 Development Is Fair

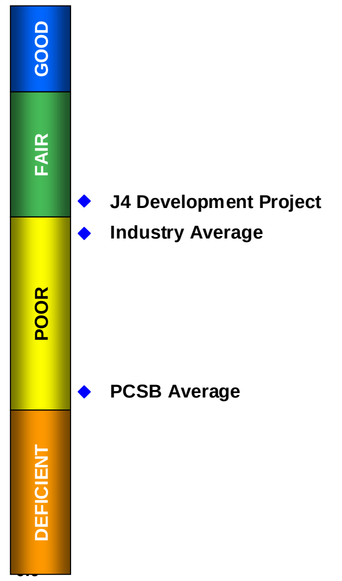


Figure 19

Figure 19 illustrates that the J4 Development Project had a Project Control Index (PCI) in the *Fair* 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 J4 Development Project's estimating methods were sufficiently definitive for all cost categories to support effective project control. The project estimate was not integrated with the project schedule. The estimate basis document was not published. The estimate was consistent with the latest design documents. Facilities and drilling estimates were based on the same scope and concepts. However, the estimate was not quantitatively 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. It also includes the extent to which historical cost data were captured in a database for future planning. The J4 Development Project used comprehensive physical progressing methods during execution. Each activity in the work breakdown structure had a physical measure associated with it. Project status reports were prepared on a biweekly basis at a summary level. All elements of execution were covered in the report (engineering, fabrication, transportation and installation, hookup and commissioning, and drilling). The reports covered both cost and schedule. An owner project control specialist was assigned to the project during execution and was actively involved in the project.

PROJECT MANAGER TURNOVER

The project team recorded project manager turnover due to an internal promotion during execution. In addition, the facilities lead turned over during fabrication, and the project controller was replaced during detailed engineering. The high turnover in the project did not have significant impact on the projects' progress because of the strong core team within each discipline and the routine nature of this project. The facilities and wells design, as explained previously, were not complicated and PCSB has vast experience in the region.

LATE DESIGN CHANGES

The J4 Development Project had major late changes after sanction. In fact, all PCSB projects to date have experienced major late changes. The most significant changes of the J4 Development Project were in the wells scope. The original plan was to drill and complete 9 single string wells, but a post-sanction optimisation study led to a reduced number of wells (7 with 11 completion strings). Therefore, a number of wells will be completed as dual completion strings. Moreover, the casing designs were found to be inadequate; the team had tried to save costs by reducing the cement used. The casing changes cost the team an additional US$2.5 million per well for the five remaining wells. The main driver of these substantial scope and design changes was the schedule constraints placed on the project during FEL, which required the team to do FEL 2, FEL 3, and FDP work in parallel.

IPA measures as a major late design change any change that take places after sanction that costs the equivalent of 0.5 percent of the sanction estimate or causes at least 1 month schedule delay. 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

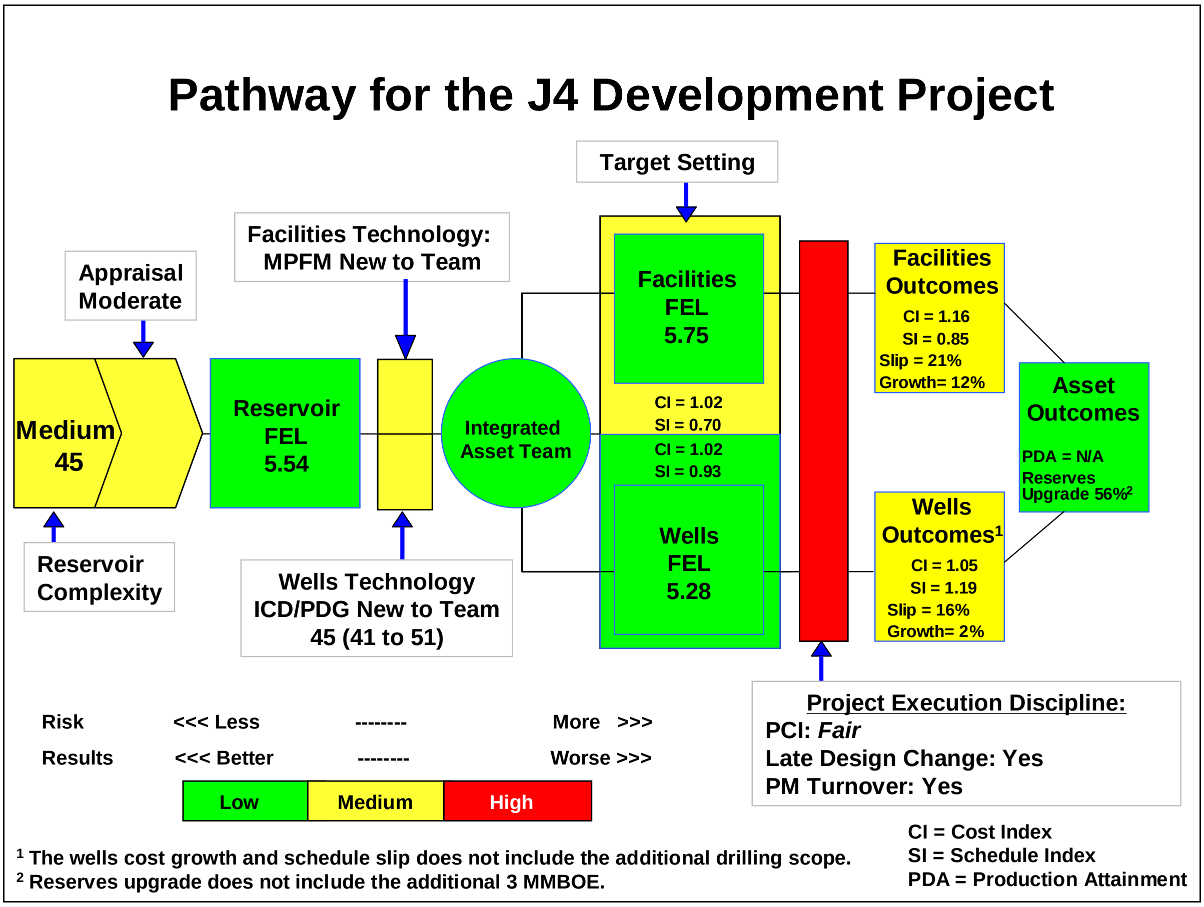


Figure 20

IPA assessed the J4 Development Project's drivers and the level of 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 J4 field development was recognised by senior management as significant and a strategic project, because of the forecast shortfall in PSC supply. The project team faced two key challenges in execution: (1) pursuing an *Aggressive* schedule, and (2) high turnover in key roles.

The J4 Development Project had better than industry average project definition and had moderate targets for cost. The project team achieved sound results in competitiveness and predictability. However, the execution schedule was aggressive, driven by the first oil date. Team integration and industry-proven technology benefited the young, relatively inexperienced, team members. Moreover, the standard design from a similar project enabled the J4 Project team to work around the lack of staffing and schedule pressure.

LESSONS LEARNED AND RECOMMENDATIONS

Based on our analysis of historical industry performance and our assessment of the J4 Development Project, we present the following key lessons for future projects.

1. *Good FEL and integrated teams assist schedule-driven projects*. Historically, projects with a *Good* FEL delivered faster. Combined with an integrated team, the aggressive schedule risks were minimised. This is because basic data had been prepared and were communicated between the various functions and disciplines.
2. *Leveraged design from the Angsi Project contributed to the J4 Development Project's competitive cost and schedule performance*. Most of the design had already been completed from the Angsi Project, and the J4 team was able to modify them to suit the J4 environment. This approach was much faster than the time the team would have needed to start the J4 design from scratch, and was especially helpful given the project's time constraints.
3. *Adequate project controls and proactive contractor management kept the project aligned with business and project objectives*. The small but proactive team worked closely with the contractors and thereby mitigated execution risks effectively and efficiently.
4. *Minimise scope and design changes during execution by completing subsurface studies before commencing FEED.* Providing basic subsurface data early improves operability and production attainment. Historically, projects that obtained all basic data before entering FEED more often achieved their business objectives that did projects that lacked timely basic data.

APPENDIX A: COST BENCHMARK ANALYSIS

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

PLATFORM JACKET ANALYSIS

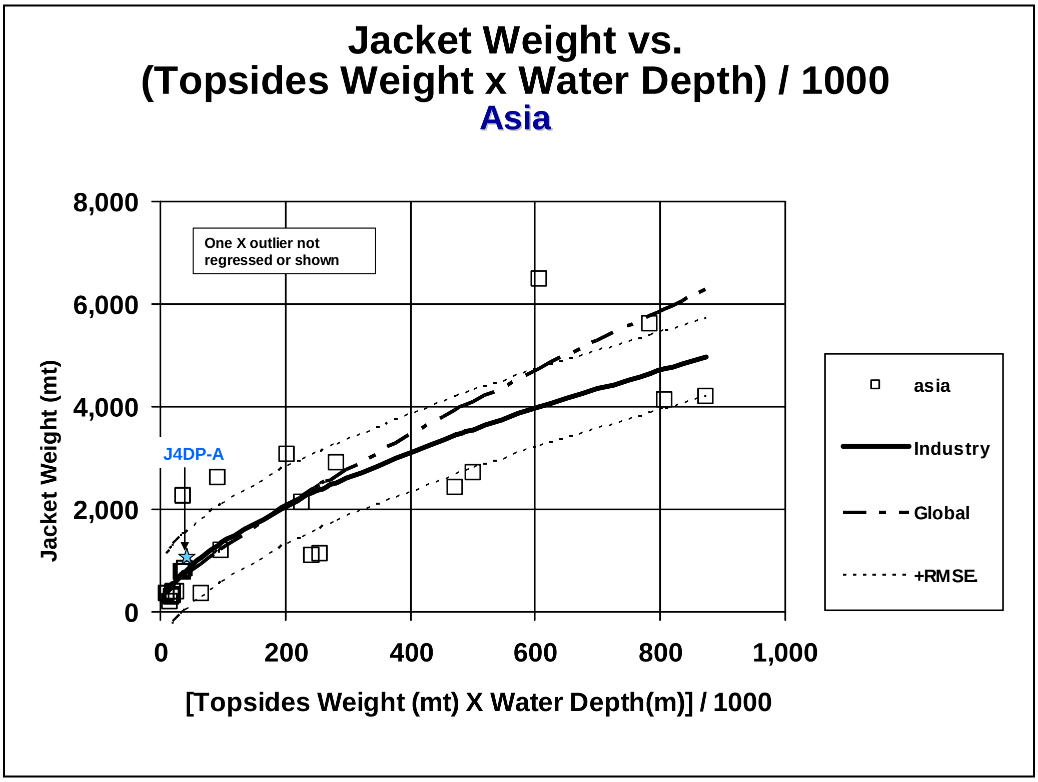
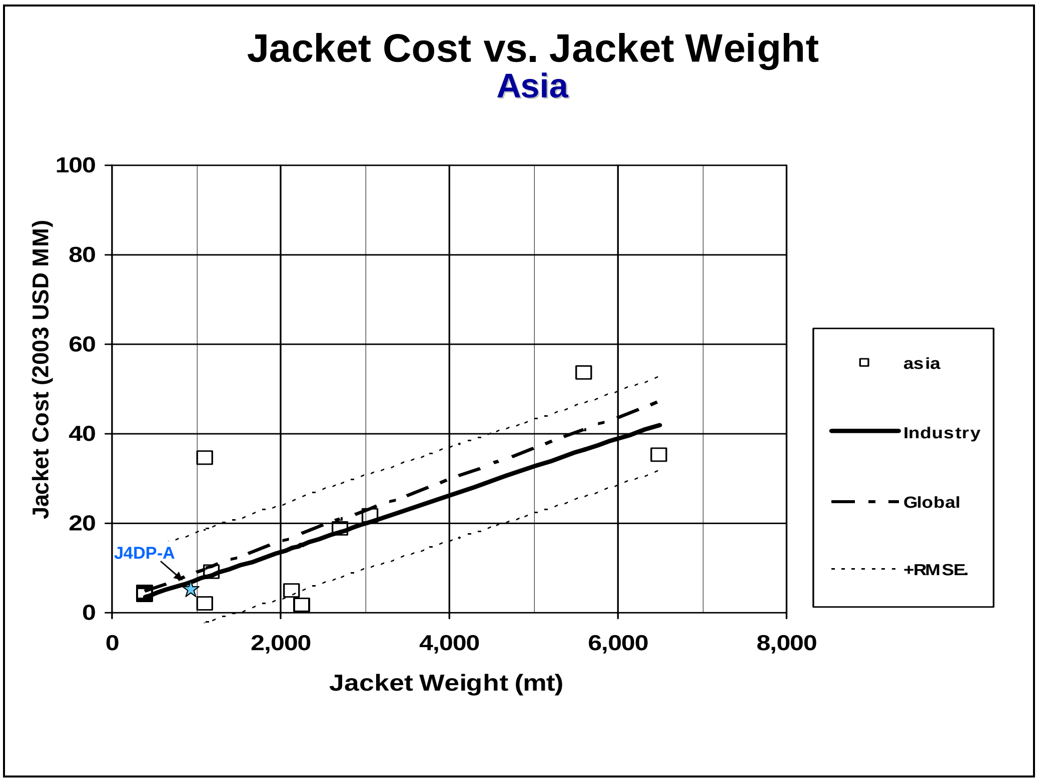


Figure 21



Jacket Cost vs. Jacket Weight
Asia
Jacket Cost (2003 USD MM)
100
80
60
40
20
0
0
2,000
4,000
6,000
8,000
Jacket Weight (mt)
J4DP-A
asia
Industry
Global
+RMSE

Figure 22

PLATFORM TOPSIDE ANALYSIS

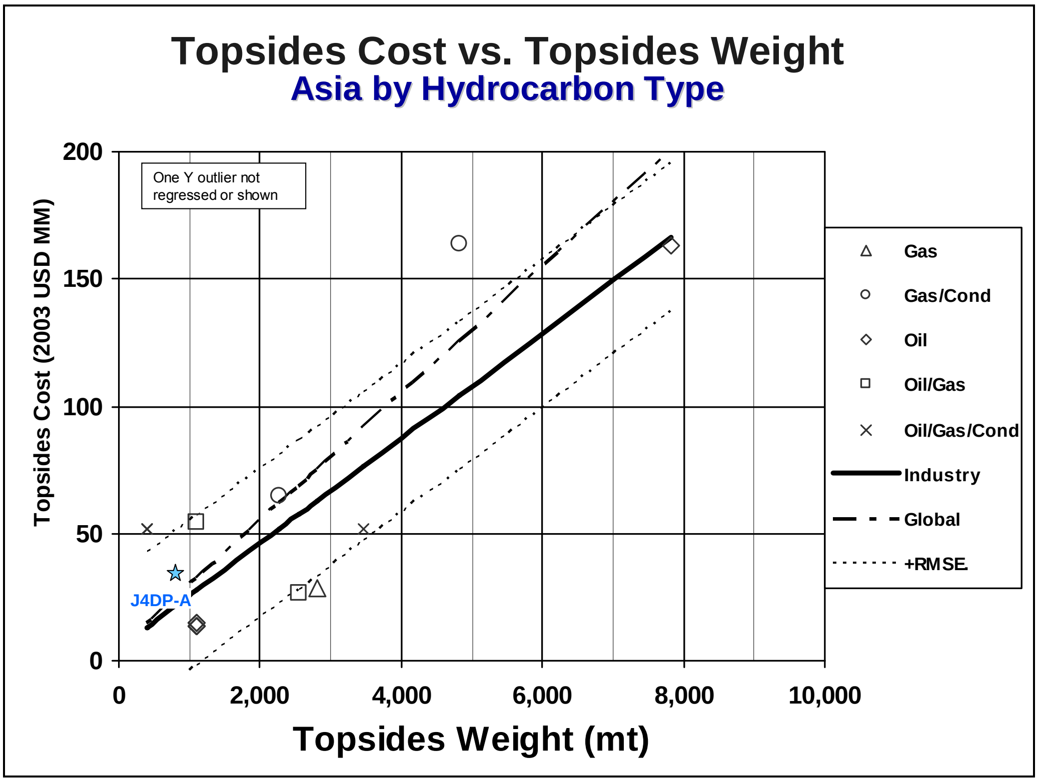


Figure 23

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 24, IPA research[34] 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 J4 Development Project.

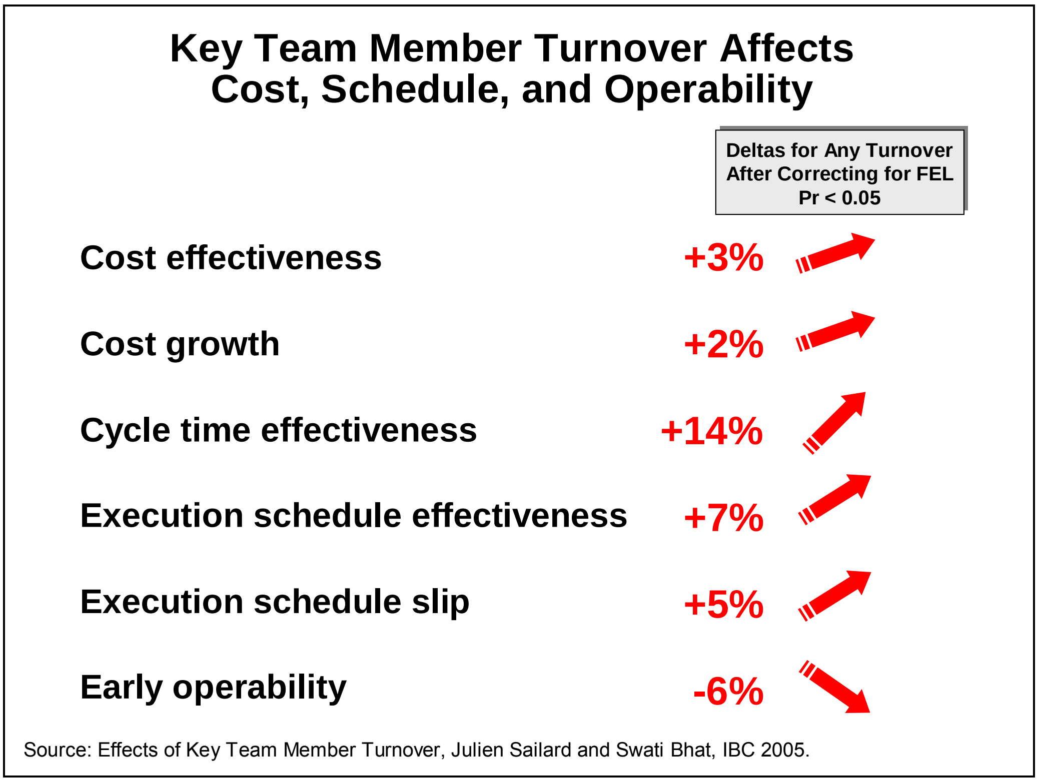


Figure 24

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 to work for a different employer. The project team can offer incentives for team members to stay in their positions until after project completion.

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.

[34] 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 3.0.

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.[35] 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.

[35] *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 23 shows the components of the PCI for closeout analyses.

Table 23
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.