FINAL

A CLOSEOUT EVALUATION OF THE SAMARANG PHASE 1 PROJECT

Prepared for
PETRONAS Carigali Sdn Bhd

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PREFACE

This IPA report summarises the performance of PETRONAS Carigali Sdn Bhd's (PCSB) Samarang Phase 1 Project. We compared the performance of this project with the performance of similar projects in Industry and with PCSB's average performance.[1] Based on this analysis, past IPA research, and input from the project team, we provide lessons learned that can be used to improve future project performance. IPA conducted a prospective analysis on this project in 2010[2], prior to authorisation.

To supply industry benchmarks, we employed IPA's Project Evaluation System (PES®)[3] using data contained in the Upstream PES Database. The Upstream PES database contains information on more than 1,200 projects conducted by more than 35 companies over the past 25 years. This closeout evaluation of the Samarang Phase 1 compares the project's performance with that of similar projects in Industry and with PCSB's average performance. Furthermore, since the project has been completed, we compare the project's actual performance with the estimates provided to management at authorisation. Based on this analysis, past IPA research, and input from the project team, we offer lessons learned that can be used to improve future project performance. This report establishes the final benchmarks for the Samarang Phase 1 Project.

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.

Members of the project team supplied the information for this analysis in meetings held 26 and 27 January 2012, in the project offices in Kuala Lumpur, Malaysia. Team members at the meeting included Chik Adnan (Project Manager), Eliff M Mazlan (Senior Electrical Engineer), Nik Mohamed Fakrul Fidzrie (Facilities Project Engineer), Sarah Binti Haris (Head of Facilities), Mimi Azura Shuhaimi (Head of Subsurface), Rasim Yildiz (Head of Production Technology), Mohamed Achmaovi (Controller), Sharifa Nazira Alchin (Cost Controller), Javier Forinz (Intelligent Operations), Tim McMillan (Completion Engineer), Haakon Roed (Wells Team Leader), Mehran Jahan Giri (Senior Planning & Scheduling Engineer), Richard Herson (Subsurface Manager), Sachin Sharma (Senior Geomodeller), Ajay Bahuguna (Reservoir Engineer), Juli Mohamad Jalaludin (Senior Reservoir Engineer), Dr. Tanwi Basu (Senior Geologist), Yopy Sosiawan (QA/QC Engineer), Mohamad Faris Rezza Johar (HUC Engineer) and Ernesto Ritorpes (Operations Engineer).

Manoj Prabhakar and Galvin Singh 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, or for answers to questions, contact Manoj Prabhakar at +65 6567-2201 or mprabhakar@ipaglobal.com or Galvin Singh at +65 6567 2201 or gsingh@ipaglobal.com.

[1] We derived PCSB's benchmarks from data presented at the 2011 annual meeting of the Upstream Industry Benchmarking Consortium (UIBC 2011). The UIBC is a voluntary association of owner firms in the upstream petroleum industry that use IPA's quantitative benchmarking approach. The members exchange data, information, and metrics to improve the effectiveness of their project systems.
[2] Adrian Kong and Trung Ghi, *Phase 1 Prospective and Phase 2 Pacesetter Evaluations of the Samarang Project,* IPA, PET-0202-PRO, April 2010.
[3] PES is a registered trademark of IPA.

TABLE OF CONTENTS

KEY MESSAGE

The Samarang Phase 1 Project team followed the new PETRONAS project process, PPMS, during Front-End Loading (FEL), resulting in drivers that were better than recent PCSB projects; in fact, better than Industry. The team built on the strong foundations that had been put in place during definition to successfully deliver on its promised first oil date. With strong FEL and effective execution discipline, the project recorded no major design changes in the wells construction and facilities scopes during execution. The significant underrun in the facilities scope cost was outside the team's control as the project was assigned a different set of marine support vessels with lower rates after authorisation. As a result of the team practices, there were no safety incidents during execution. The ultimate success of the Samarang Phase 1 project will be determined by production attainment. While there are some preliminary data that indicate that measure is good, the final metrics are not yet available. The experience of the Samarang Phase 1 Project demonstrates the value of having a fully resourced team and following a stage-gated project management system.

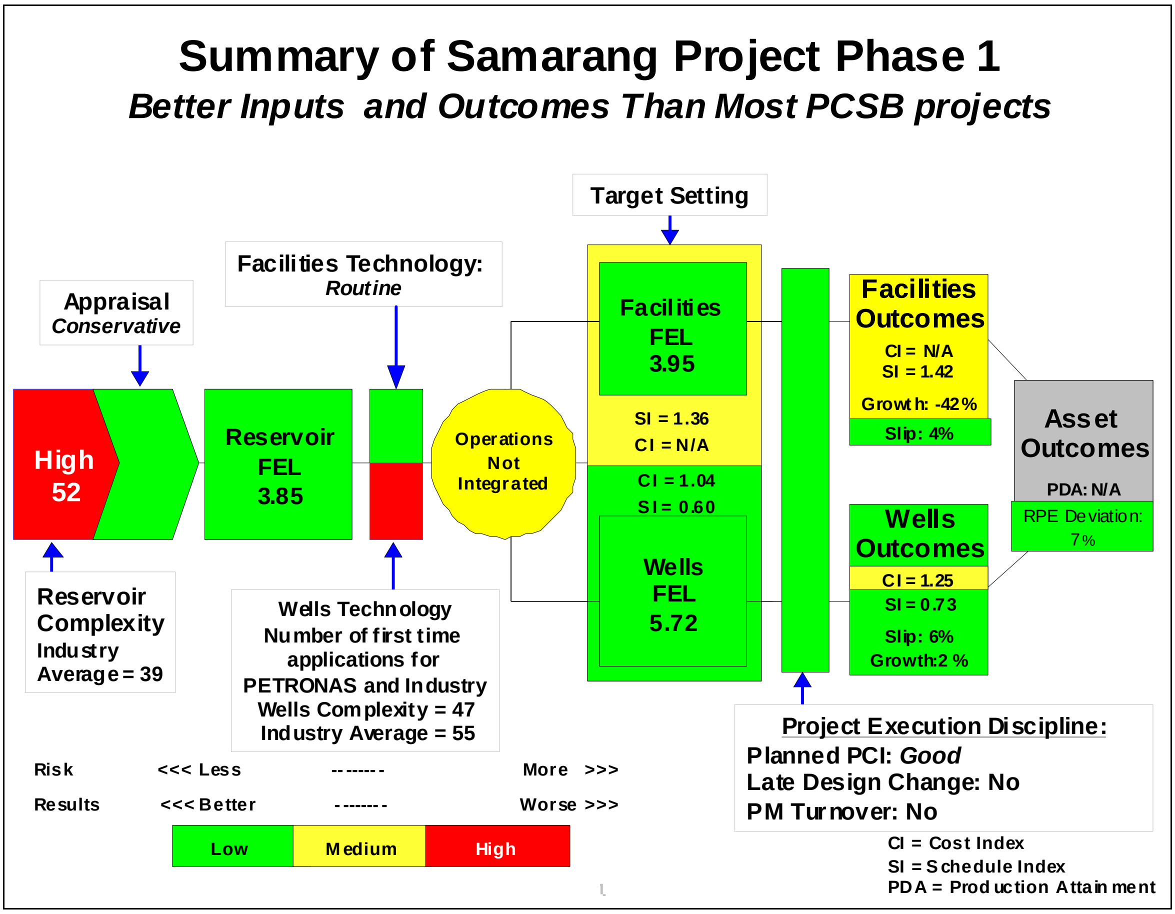

Figure 1

Table 1
Summary of Outcome Metrics for the Samarang Phase 1 Project

Outcome Metric	Samarang Phase 1 Project		Industry Average	PCSB Average[4]
	Estimated at Authorisation	Actual		
Cost Effectiveness				
Wells Component (Index)	94 (1.04)		90 (1.00)[5]	(0.43)
		95 (1.25)	76 (1.00)	(0.53)
Cost Deviation				
Asset	Not Applicable	-11 percent	7 percent	5 percent
Facilities	Not Applicable	-42 percent	5 percent	17 percent
Wells	Not Applicable	2 percent	6 percent	4 percent
Schedule Effectiveness				
Facilities Execution (Index)	23.1 months (1.36)	24.1 months (1.42)	17 months (1.00)	(1.04)
Well Construction (Index)	154 days (0.60)		255 days (1.00)[6]	(0.80)
		163 days (0.73)	223 days (1.00)	
Schedule Deviation				
Facilities Execution	Not Applicable	4 percent	10 percent	20 percent
Resource Promise Estimate (RPE)				
RPE Change from Authorisation to First Production	Not Applicable	7 percent	–8 percent	-9 percent

4 Company metrics are as reported at the November 2011 annual meeting of the Upstream Industry Benchmarking Consortium (UIBC 2011).
5 Benchmarks were normalised by adding US$7.76 million for the cost of P&A in drilling cost.
6 Benchmarks were normalised by adding 22 days, which was used for P&A in drilling (casing replacement).

PROJECT OVERVIEW

SUMMARY

IPA developed a Pathway to Success for large upstream capital projects, as shown in Figure 2. The key elements include reservoir complexity, appraisal strategy, project definition (for reservoir, well construction, and facilities), complexity, project technology, team integration, target setting, and project execution discipline. Each element is colour coded on a three-color, or “traffic light” basis to signify the project risk. Red indicates high risk, yellow indicates average risk, and green indicates low risk.

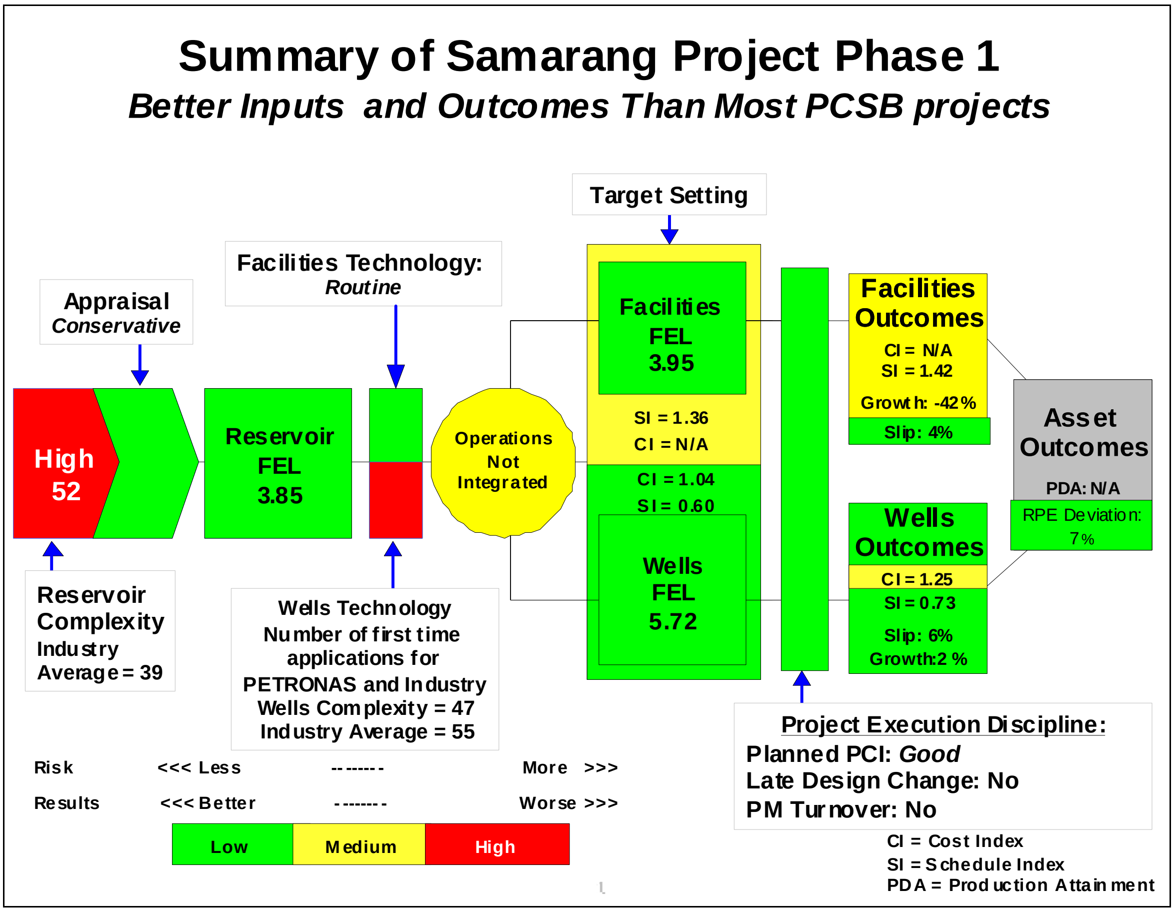

Figure 2

The Samarang Phase 1 Project was based on developing a heavily faulted, highly stacked reservoir. However the Reservoir Appraisal was rated *Conservative*, because of the large body of information that was available from this mature, producing field. The team used these data to develop comprehensive geological modelling and reservoir management plans prior to authorisation. Driven by the stacked reservoir and surveillance requirements, the Samarang Phase 1 Project had complex wells that included technologies that were new to PCSB and Industry, which were successfully implemented. Facilities technology was conventional.

The Samarang Phase 1 Project was well staffed. Sufficient resources were available to do FEL and manage execution. There was consistent communication among the wells, subsurface and facilities groups, which is not the case in many projects, and this contributed to the good definition work done. One area of weakness in the team was that the project did not have consistent and accountable operations input into design decisions. As a consequence, there are a small number of minor design items that need to be rectified on the SMJT-F platform's deck extension before handover to operations.

The wells programme incurred 6 percent slip in schedule and 2 percent cost growth despite optimal Wells FEL. Significant delays were experienced on the first well but the team was able to make up some of the time on the subsequent four wells.

The project facilities incurred a 42 percent cost underrun and 4 percent schedule slip despite *Best Practical* Facilities FEL. Most of the underrun was in the cost of the marine support vessels. A vessel package with a lower spread rate was offered after authorisation. Also, since there was work taking place simultaneously with the drilling scope, the facilities team opted share crew boats with the drilling team instead of using its own, which further reduced the cost of vessels to support offshore work.

Execution discipline on the Samarang Phase 1 Project was good. There were no major late changes in the wells or facilities scope. Several control practices were used, including earned value analysis and periodic service quality audits meeting with contractors to check on progress and resolves issue early. There was no turnover of any key team members.

Detailed production data are not yet available because of a lack of metering at the field. Preliminary data are available from production logging tools and extended well tests. This metric will updated in the future after meters have been installed and steady-state production can be measured. Based the static geological model updated with data from the latest new wells, the resource promise estimate (RPE) increased by 7 percent since authorisation.

PROJECT OBJECTIVES

The objective of the overall Samarang Project was to implement a comprehensive field redevelopment plan focused on reserves addition, optimising hydrocarbon recovery from the field throughout its life, and increasing production through application of new technologies and field management techniques. The project was originally planned to be executed as a single development but was later split into two phases. The objective for Phase 1 was to accelerate the first oil for the Samarang field redevelopment plan and obtain further reservoir data for Phase 2, which would carry out the enhanced oil recovery (EOR) program. The project was authorised for US$133 million to complete the scope in 23.1 months. The RPE at authorisation was 8.2 MMBOE.

PROJECT SCOPE

The Phase 1 project scope comprised drilling five new oil producers. One was planned at the existing SMDP-B platform and four at the existing SMJT-F platform. The SMDP-B well was a sidetrack that reused a slot on the platform. For SMJT-F, a deck extension was part of the project scope, to add four additional well slots, one of which could house a splitter wellhead. Well tie-ins and installation of monitoring systems were also part of the project scope. The proposed Samarang Phase 2 Project will involve additional drilling and implementation of EOR.

PROJECT HISTORY

Shell was the previous operator of the Samarang field and relinquished the concession to PCSB in April 1995. In total, Shell and PCSB drilled more than 100 wells in the field to date. There are seven platforms in the field. The present development of the

Samarang field is done as an alliance between PCSB and Schlumberger, with PCSB as the operator. Geological modelling done by the alliance indicated areas with significant remaining oil reserves. These reserves would require additional wells for production. There are two main plays, attic oil trapped against the field's major faults, and oil accumulations that did not have aquifer support due to the presence of faults and/or structural highs. These findings led to the plan for further development work in the Samarang field.

The initial plan was to conduct all of the development as a single phase. In late April 2009, PETRONAS decided to bring forward some drilling work to take advantage of a rig that was available in June 2010. This would have also brought forward the first oil date for the overall development. The team planned a five-well drilling program that had the added benefit of providing updated reservoir data to help plan the EOR scope. The project was thus split into two phases. Phase 1 was to drill the five wells and Phase 2 was to perform the remaining scope.

To meet the rig's availability dates, Phase 1 authorisation was planned for November 2009. Perunding Ranhill Worley was contracted to do front-end engineering for the deck extension and tie-in scope for the platforms; the contractor started work on this scope in June 2009. However, the negotiations to extend the alliance contract took longer than planned and the project could not be authorised in time to meet the rig availability window. In the meantime, Perunding Ranhill Worley was asked to continue the detailed engineering. All engineering work was completed in December 2009. The alliance contract extension was signed in March 2010. The project was then authorised in April 2010 with spud planned for May 2011.

After competitive bidding and project authorisation, the EPC contract for the facilities scope was awarded to Kencana Holding (KHL). This was the first time that KHL was working in East Malaysia. However, KHL was familiar with the PCSB work process through previous work in Peninsular Malaysia. As KHL did not have a fabrication yard in the area, a yard was rented from Oceancare in Labuan. The project team improved the safety signage at the yard and, together with the contractor, implemented PCSB's safety policies at the yard. Around this time, the team was informed that a rig from a PCSB field in Vietnam would be available in February 2011. This would give the team the opportunity to bring forward the start of the drilling campaign; the work on the deck extension started earlier than planned.

The team used quantity surveyors to confirm progress and implemented a quality control plan, which included extensive non-destructive testing of welds. The fabrication work proceeded without major incident. There were no major safety incidents reported during fabrication. Fabrication was completed in December 2010, more than a month earlier than planned. As the work was mainly structural, there was minimal onshore commissioning needed before the deck extension was ready for offshore installation.

The team kept operations personnel regularly informed on the status of offshore activities. This was made somewhat easier as the SMJT-F and SMJT-B platforms are normally unmanned. The first part of the offshore work was installation of the SMJT-F deck extension and some minor work in SMJT-B in January 2011. This work was done during the monsoon season to meet the rig availability in February 2011, but there were no major weather-related delays. Work on this scope was completed on schedule. The tie-ins and installation of control systems for the well were done after the drilling campaign.

The start of the drilling campaign could not be accelerated because the rig was released late from the field in Vietnam. In addition to the long mobilisation distance, the rig had to undergo minor repairs at Labuan before commencing the work (jetting system clean-up of one leg). In the end, the rig arrived at the Samarang field almost 3 months later, in May 2011. Hence, the actual spud date was close to the dates planned at authorisation.

Drilling started with the B-66 sidetrack well on the SMJT-B platform. Drilling and completion were done sequentially so that the project could achieve first oil as planned. There were a number of issues that lengthened the wells construction duration for the B-66 well from 37 to 60 days. Among the more significant issues was the replacement of a corroded intermediate casing string; the team had anticipated that this could occur and had replacement casing of the correct size available. There were other minor issues that together contributed to the extended duration. An important success for this well was the recovery of 180 feet of core, which was very important for reservoir understanding to improve the next Samarang field development phase.

After the first well, the drilling team held a workshop to discuss and document the lessons learned from drilling the B-66 well for the remaining wells. Also after the first well, the original dual-tubing contractor, KST, was dismissed due to poor safety practices and inadequate equipment. Frank's International (Selaut) took over the remaining work. There were no safety incidents during the drilling campaign.

The original plan at authorisation was to construct all wells sequentially. However, after the first well the team decided that it was more efficient to do batch drilling. Hence, all the other four wells at SMJT-F were drilled batch-wise, with drilling taking place first for all wells and completions later. The team again conducted a lesson learned review after each well, helping to keep the overall drilling campaign on schedule. The overall non-productive time on the drilling programme was lower than expected. The team used a decision tree process, which allowed the drillers to make decisions offshore and continue working. In addition, some completion offshore support vessels that the team had originally planned to use were not available, but this did not affect the project because the support vessels were ultimately not needed. The rig contract also expired midway through drilling campaign and the day rate changed from US$180,000 per day to US$120,000 per day. A delay that was outside the team's control occurred at the completion of the campaign; rig demobilisation was delayed by 2 days when the tug boat transporting it was late. The project had to assume the rig rate for that duration.

During the drilling campaign a larger-than-expected number of target zones were found to be oil-bearing zones. Not all of these zones could be completed, because the wells were already quite complex and adding further production zones would have increased the operating difficulty of the wells. There were technological challenges and risks encountered in drilling that the team was able to meet successfully. These included the first successful casing-while-drilling in Malaysia, installation of multiple downhole gauges in the wells, and the world's first application of PERFPAC, an integrated single run perforation and gravel packing operation.

The tie-in work for the SMJT-F wells was done after all the wells were completed. The daily work boat commutes to and from shore were centred around the well construction needs; this resulted in some lost productivity, but as the completion durations were 2 to 3 days longer than the required tie-in durations, there was some float that kept the end-date on schedule.

Operations has not taken over the platform from the project team because three items have yet to be rectified. These items are the installation of an access ladder to reach a choke valve, the addition of a cover for the fluid sampling unit, and the change of a pressure gauge to be the same as the others on the platform. Another issue that needs to be rectified is an incorrectly sized double block-and-bleed valve in the flowline. This is not inhibiting production flow because the well needed to be choked back anyway, but the valve will need to be replaced. These issues are expected to be resolved in the next planned platform shutdown in February 2012.

BASIS OF COMPARISON

In this report, we use IPA's Upstream Database to compare the Samarang Phase 1 Project with similar industry projects. The database contains more than 1,200 projects with costs ranging from less than $5 million to more than $50 billion. Over 19 percent of the projects are in Asia. The basis of comparison key metrics are highlighted in Table 2 through Table 4. The Samarang Phase 1 Project comprises revamp of a platform and drilling of five producer wells. The revamp and well scopes are well within the range of characteristics of our standard offshore revamp model and well construction datasets.

Table 2
Characteristics of the TEC Model Dataset

Characteristic	Samarang Phase 1 Project	Dataset (143 projects)		
		Minimum	Median	Maximum
Region	Asia	GoM, 19%; Europe, 35%; Africa, 11%; Asia, 15%; South America, 11%; Other, 9%		
Year of Authorisation	2010	1990	2001	2008
RPE (MMBOE)	12.2	4.2	107	>3,200
Water Depth (m)	17	2	126	>2,500
Cost (^{MOD}US$ million)	138	9	310	>7,300

Table 3
Characteristics of the Offshore Revamp Dataset

Characteristic	Samarang Phase 1 Project	Dataset (143 projects)		
		Minimum	Median	Maximum
Year of Authorisation	2010	1990	2001	2008
Cost (^{2011}US$ million)	39.5	0.1	33	600
Region	Asia	GoM, 12%; Europe, 55%; Africa, 8%; Asia, 17%; Other, 8%		

Table 4
Characteristics of the Well Construction Model

Characteristic	Samarang Phase 1 Project	Dataset (112 projects)		
		Minimum	Median	Maximum
Year of Authorisation	2010	1994	2003	2008
Programme Duration (Days)	176	12	240	>2,000
Region	Asia	North America, 24%; Europe, 30%; Africa, 13%; Asia, 18%; Oceania, 10%; South America, 5%		
Water Depth (m)	17	3	120	>2,500
Number of Wells	5	1	4	50

PROJECT BENCHMARKS

PROJECT OUTCOMES

Summary

Table 5, Table 6, and Table 7 summarise the estimated and actual outcomes for the Samarang Phase 1 Project's cost, schedule, RPE, and operability. Industry and PCSB benchmarks are presented for comparison. Schedule and cost are evaluated for both *predictability* (did the project met its planned schedule/cost targets) and *competitiveness* (position of the project relative to other projects in Industry).

Table 5
Summary of Cost Outcome Metrics for the Samarang Phase 1 Project

Outcome Metric	Samarang Phase 1 Project		Industry Average	PCSB Average[7]
	Estimated at Authorisation	Actual		
Component Cost Effectiveness – US$ million				
Facilities Component (Index)	Not Available	Not Available	(1.00)	Not Available
Wells Component (Index)	94 (1.04)		90 (1.00) [8],[9]	(0.43)
		95 (1.25)	76 (1.00)	(0.53)
Cost Deviation				
Asset	Not Applicable	-11 percent	7 percent	5 percent
Facilities	Not Applicable	-42 percent	5 percent	17 percent
Wells	Not Applicable	2 percent	6 percent	4 percent

No facilities cost benchmarks are provided because we do not have enough similar (offshore revamp) projects in Malaysia to provide a strong basis for a cost index. The Samarang Phase 1 wells cost is higher than Industry, driven by the high well completion costs. Multizone completions and sand control measures have been controlled for in the wells construction cost model. However, other factors that are uncommon in industry, such as shared conductor and casing wells, casing while drilling, multiple gauges in each well and dual completions, and new technology components, such as PERFPAC, are not controlled for the model but contribute to the high wells costs.

Facilities costs underran by 42 percent; wells costs overran by 2 percent. The facilities cost underrun was driven by the offshore support vessel spread rate reduction as described earlier. The overall asset cost deviation versus the authorised project cost was an underrun of 11 percent. There were no major late changes to drive cost deviation, reflecting the strong project definition work that been done.

[7] Company metrics are as reported at the November 2011 annual meeting of the Upstream Industry Benchmarking Consortium (UIBC 2011).
[8] IPA updated the well model, so we use the new model to determine the benchmarks for the well component cost analysis and its duration. In the Samarang Phase 1 prospective report, we presented the benchmark based on the old model, which varies significantly from the one presented here.
[9] Benchmarks were normalised by adding US$ 7.76 million for the cost of P&A in drilling cost.

Table 6
Summary of Schedule Outcome Metrics for the Samarang Phase 1 Project

Outcome Metric	Samarang Phase 1 Project		Industry Average	PCSB Average
	Planned at Authorisation	Actual		
Schedule Effectiveness				
FEL 3 Duration	Not Reported	Not Available	Not Reported	Not Available
Facilities Execution (Index)	23.1 months (1.36)	24.1 months (1.42)	17 months (1.00)[10]	(1.04)
Well Construction (Index)	154 days (0.60)		255 days (1.00)[11,12]	(0.80)
		163 days (0.73)	223 days (1.00)	
Schedule Deviation				
Facilities Execution	Not Applicable	4 percent	10 percent	20 percent
Well Construction	Not Applicable	6 percent	Not Applicable	Not Applicable

IPA analysed the facilities scope and well programme execution schedules compared to global industry benchmarks. Based on the project's actual completion date in August 2011, the facilities execution duration was 24.1 months, which is 42 percent longer than the industry average. The early start of detailed engineering (prior to authorisation), because of delays in finalising the alliance with Schlumberger, is the main reason for the long execution period. The team had opportunities to accelerate the project in execution but this did not materialize because of difficulties in obtaining a rig.

The Samarang Phase 1 Project schedule predictability was better than recent PCSB projects. The facilities execution schedule deviated from the initial planned duration by 4 percent, which is better that the industry average of 10 percent deviation and the PCSB average of 20 percent.

The Samarang Phase 1 well construction was faster than Industry. However, more days were needed than planned, because of the extended time for mobilisation of the rig and drilling difficulties at one of the wells. The wells duration overran plan by 6 percent.

Table 7
Samarang Phase 1 Project Resource Promise Estimate and Attainment Summary

Outcome Metric	Samarang Phase 1 Project		Industry Average	PETRONAS Average
	Estimated at Authorisation	Actual[13]		
RPE	8.2 MMBOE	8.7 MMBOE	Not applicable	
Change in RPE from authorisation to first production	Not Applicable	7 percent	–8 percent	-9 percent
Likelihood of significant (at least 20 percent) RPE downgrade	14 percent	Not applicable		
Production Attainment in Months 7-12*	100 percent	Not yet available	82 percent	78 percent

*Production data not available for months 7-12 months after start of production.

The RPE of the Samarang Phase 1 Project increased by 7 percent from that planned at authorisation. More drilling targets were oil-bearing than had been expected. Given the

[10] We used the updated model to derive the duration benchmark for both planned and actual, thus this benchmark differs from that given in the prospective report.
[11] We used the updated model to derive the duration benchmark for both planned and actual, thus this benchmark differs from that given in the prospective report.
[12] Benchmarks were normalised by adding 22 days, which was used for P&A in drilling (casing replacement).
[13] The actual RPE presented here is based on the latest revised estimate supplied to IPA at the project interview. The project had not yet entered production at that time.

number of zones and the reservoir complexity, the team was not able to complete all zones with the five wells. The subsurface team updated the static model with information from the new wells. The current RPE 8.7 MMBOE, but is likely to change once the dynamic model revision is completed.

The Samarang Phase 1 Project achieved first oil as planned. The produced oil flows to the Labuan Crude Oil Terminal (LCOT) together with production from other PCSB and Shell assets in the area. The Samarang field does not have a metering system, so “back allocation” is done based on total inflows to LCOT to establish the Samarang field’s production numbers. There is generally a lag of about 6 to 12 months in obtaining these values. Based on extended well tests and production logging tools, the Samarang Phase 1 wells are flowing at 5,200 barrels per day, this which is more than double the authorisation amount of 2500 barrels per day. This difference is partly because of the increased volumes that were discovered during drilling but also because a conservative view was taken at the time of authorisation. Operational meters will be installed in mid-2012 to record field production. Production data for months 7 to 12 are therefore expected toward the end of 2012.

Details

Cost

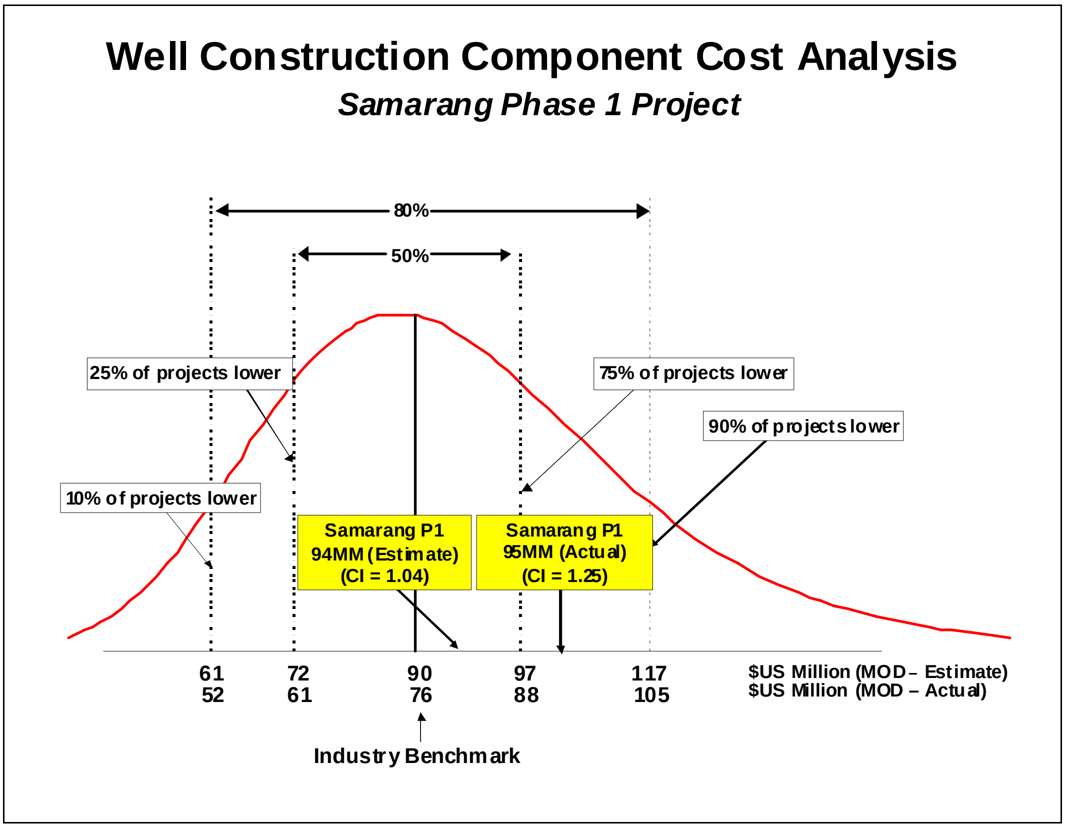

Figure 3

Figure 3

shows the cost benchmarks for the Samarang Phase 1 Project’s wells program. US$11 million was added to the cost benchmark to account for the cost of Plug and Abandon (P&A) and casing repair in the B-66 well.

At the time of authorisation, the Industry cost for a scope similar to Samarang Phase 1 was $90 million. The project team’s estimate of $94 million was 4 percent higher than that.

The actual Samarang Phase 1 Project cost of $95 million is 25 percent higher than Industry. Project costs in Asia average about 40 percent lower than the global benchmark.

At the time of the Samarang Phase 1 Project prospective evaluation, the wells construction cost benchmark was US$31 million. The benchmark change is due to a change in cost modelling methodology. The previous model gave a total wells program cost benchmark based on overall program characteristics such as number of wells, number of re-used wells and average wells complexity. The updated model predicts costs based primarily on the total program drilling and completion duration benchmark. This wells construction program benchmark duration is derived from individual well benchmarks that use specific scope based aspects, and then adding them to get a total duration. These scope based aspects are discussed in the Wells Construction Duration Section below. The model datasets have also been updated since the time of the prospective evaluation with newer projects.

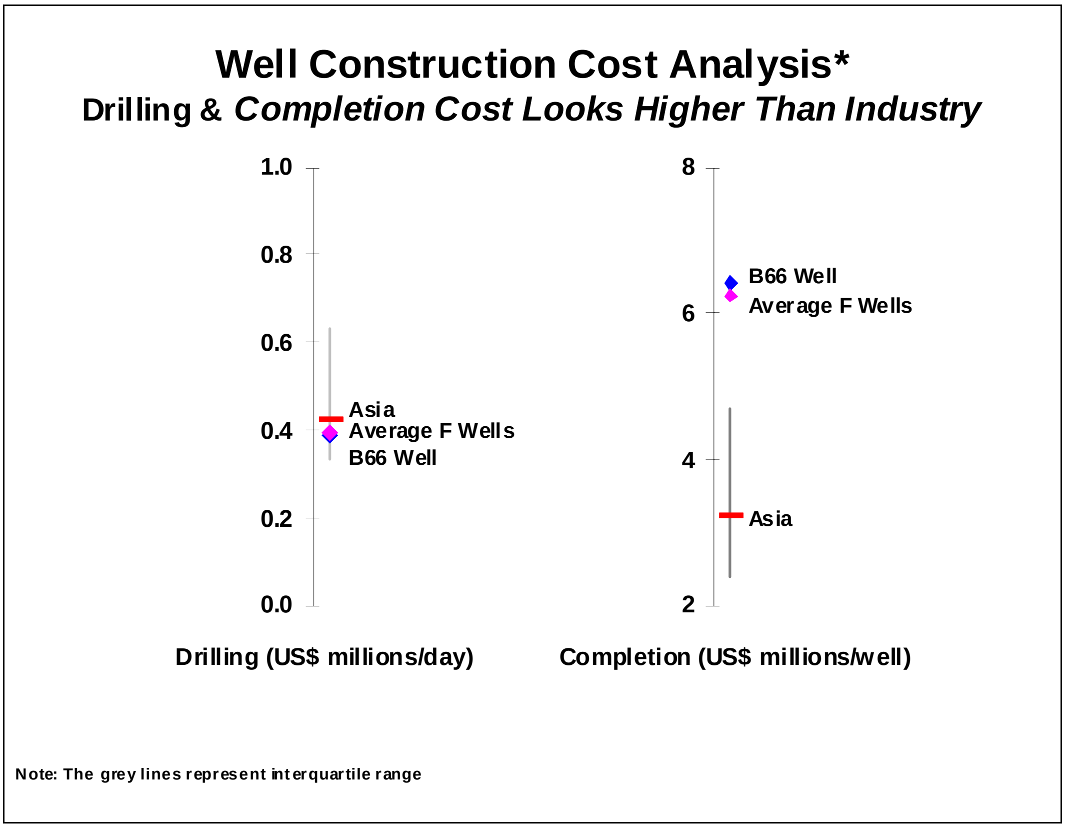

Figure 4

Figure 4 compares the cost of the Samarang Phase 1 wells to a comparison dataset of 10 projects in Asia with multizone completions and sand control. The main driver of the high wells cost in the Samarang Phase 1 project is the completions scope. For all the Samarang Phase 1 wells, completion costs per well were higher than those in the comparison dataset. The use of dual completions strings and multiple downhole gauges in the Samarang Phase 1 wells contribute to this cost. However, the detail available for the comparison projects completions scopes is insufficient to control for these aspects.

In contrast, the drilling costs per day were well within the average spread rates in Asia.

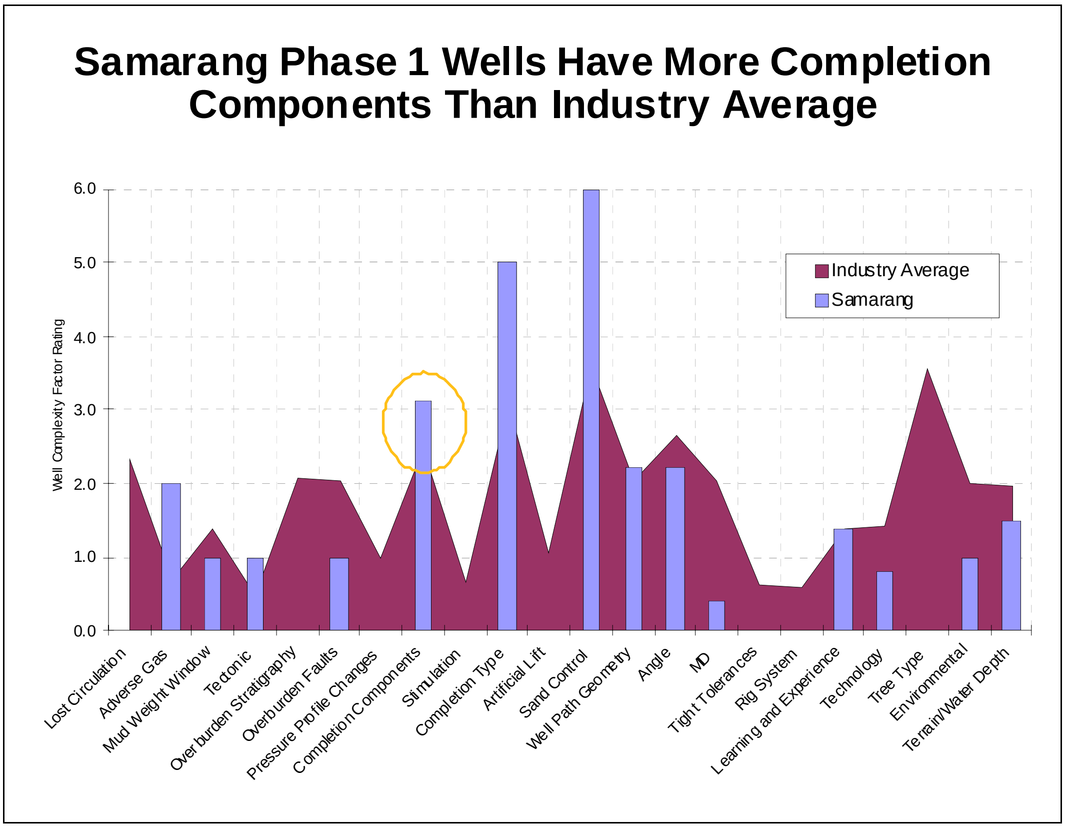

Figure 5

Figure 5 shows the various aspects of the Samarang Phase 1 wells complexity in comparison with the industry average. The Well Construction Component Model[14] controls for multizone completions and sand control, but there more pieces of completion equipment installed downhole for the Samarang Phase 1 wells in this project than typical for Industry, which contributed to the higher wells costs.

[14] The Well Construction Component Cost Model produces an industry average total well construction program cost benchmark given the design choices of the project team (number of wells, well paths, complexity, etc.). This model relies on the total program duration benchmark as the primary independent variable. The model also controls for water depth.

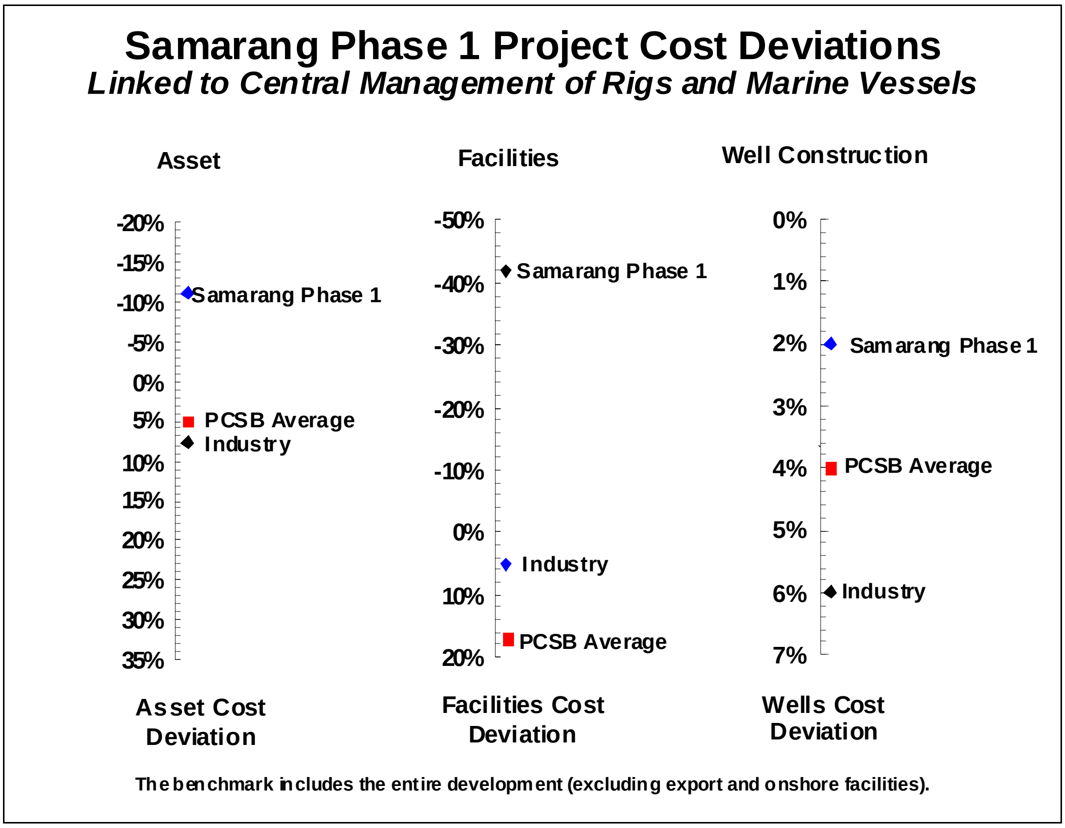

Figure 6

Figure 6 shows the cost deviation of the Samarang Phase 1 Project compared with Industry. Total development, facilities, and well construction costs are broken out to compare them with industry cost deviation. These deviations remove market escalation over the execution duration of the project.

The Samarang facilities cost have a cost underrun of 42 percent, most (32 percent) of which is attributed to the cost savings in the set of marine support vessels the project used. As discussed in the History section, this was the result of a change in the vessels that were allocated to the project at the time of authorisation. The more expensive vessels included larger work boats for accommodation and other crew boats. With the cheaper set of marine vessels, fast crew boats were used to shuttle people from shore during execution of drilling and facilities. The use of helicopters was reduced. Optimisation among drilling and facilities execution further helped to reduce the marine support vessel costs. Also, the project had no major downtime caused by HSE, operations, weather, or travel. The average PCSB project has had 41 percent cost growth in facilities.

The wells scope for the project were nearly exactly on budget with only a 2 percent overrun. During the demobilisation, 2 rig days were lost waiting for the transport vessel to arrive.

The cost deviations for the Samarang Phase 1 Project were mostly caused by resource management that was external to the team. There were no major design changes that caused deviation in cost.

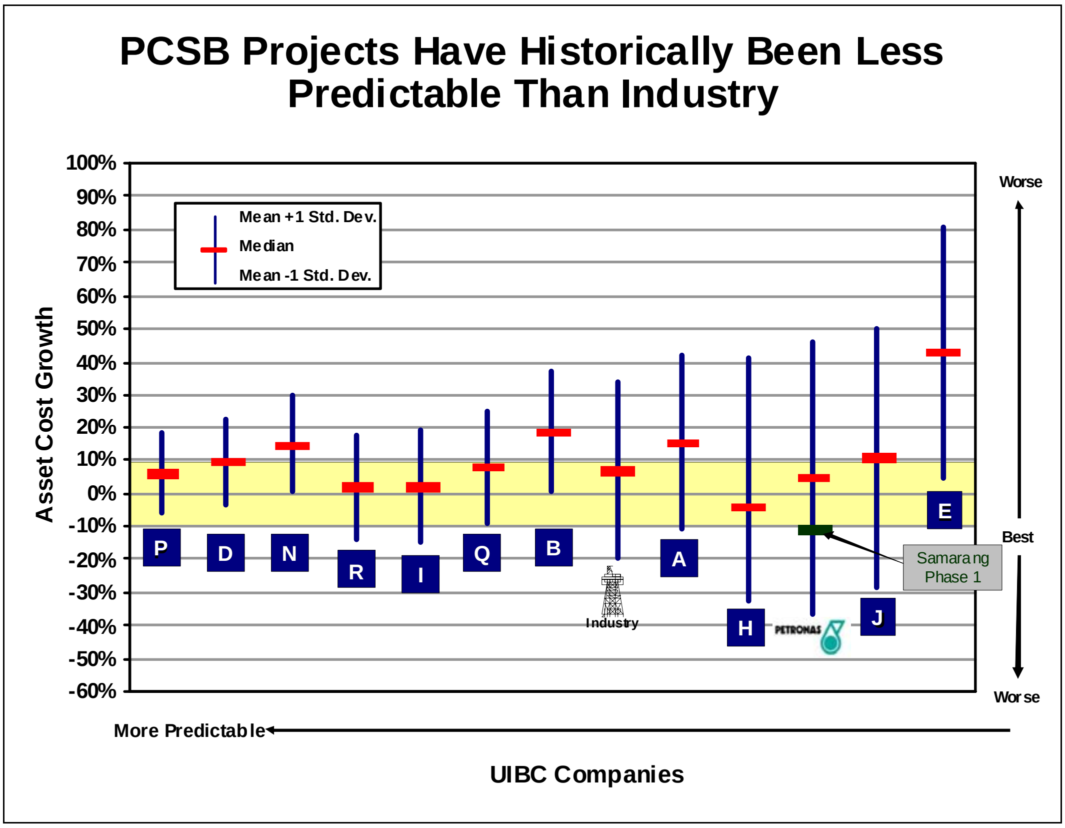

Figure 7

As shown in Figure 7, the PCSB projects have historically had larger deviations in asset costs from authorisation to completion than other companies in Industry. If PCSB were consistently able to complete projects with the same deviation as the Samarang Phase 1 Project, overall company performance would be much closer to Industry average.

Schedule

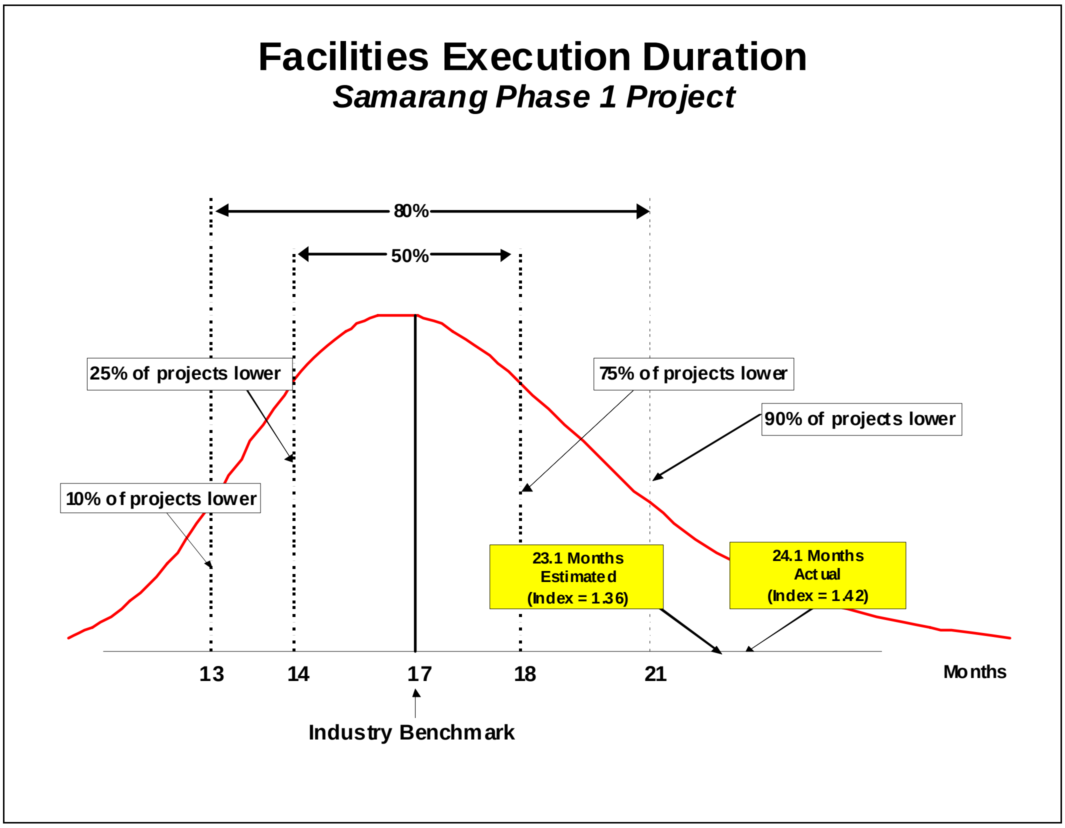

Figure 8

As shown in Figure 8, the planned execution duration of the Samarang Phase 1 Project is 23.1 months, which was 36 percent longer than the industry average of 17 months.[15] The actual duration of the project was 24.1 months, which is 42 percent longer than the industry average of 17 months. To make comparisons with industry, the execution duration is measured from the start of detailed engineering to the completion of scope.

In the case of the Samarang project, there was a gap of 3 months in execution (between the end of detailed engineering and the start of fabrication work) because of the delay in concluding the PCSB-Schlumberger alliance contract. IPA typically adjusts for factors that are unusual and outside the organisations control such as strikes, natural disasters, etc. While it was prudent to wait for an agreement before authorising the project, it was an internal management decision to do so. Hence, we do not adjust for this in the benchmark.

The Samarang Phase 1 Project had a longer execution duration than similar projects in Industry. Projects in industry typically overlap detailed engineering and fabrication work resulting in a shorter execution duration but this could not be done for the Samarang Phase 1 Project because the delays in the conclusion of the alliance contract. The project team recognised that it could accelerate the project, and were prepared to do so. However, these opportunities could not be realised because of the unavailability of the drilling rig, which was managed centrally by PETRONAS.

The Offshore TEC (Time of Engineering and Construction) Model provides the industry average time for engineering and construction for similar offshore facilities based on cost (which is a proxy for project size and complexity), revamp percentage, location, and

[15] We used an updated model to derive the Industry duration benchmark, thus it is different from the benchmark provided in the prospective report.

weather window. The model is applicable to a variety of offshore concepts including fixed platforms, floaters, subsea tie-backs, and revamps.

At the time of the prospective evaluation of the Samarang Phase 1 Project, the execution duration benchmark provided was 12 months. The change in benchmark is due to a model update; it mainly included more recent projects. In addition, more data were incorporated around the effects of revamp and weather windows on offshore project schedule. These factors were found to be significant drivers of duration and were added to the model to provide a more comprehensive metric.

Table 11 in Appendix A summarises the Samarang Project Phase 1 actual and planned schedules and compares them with Industry.

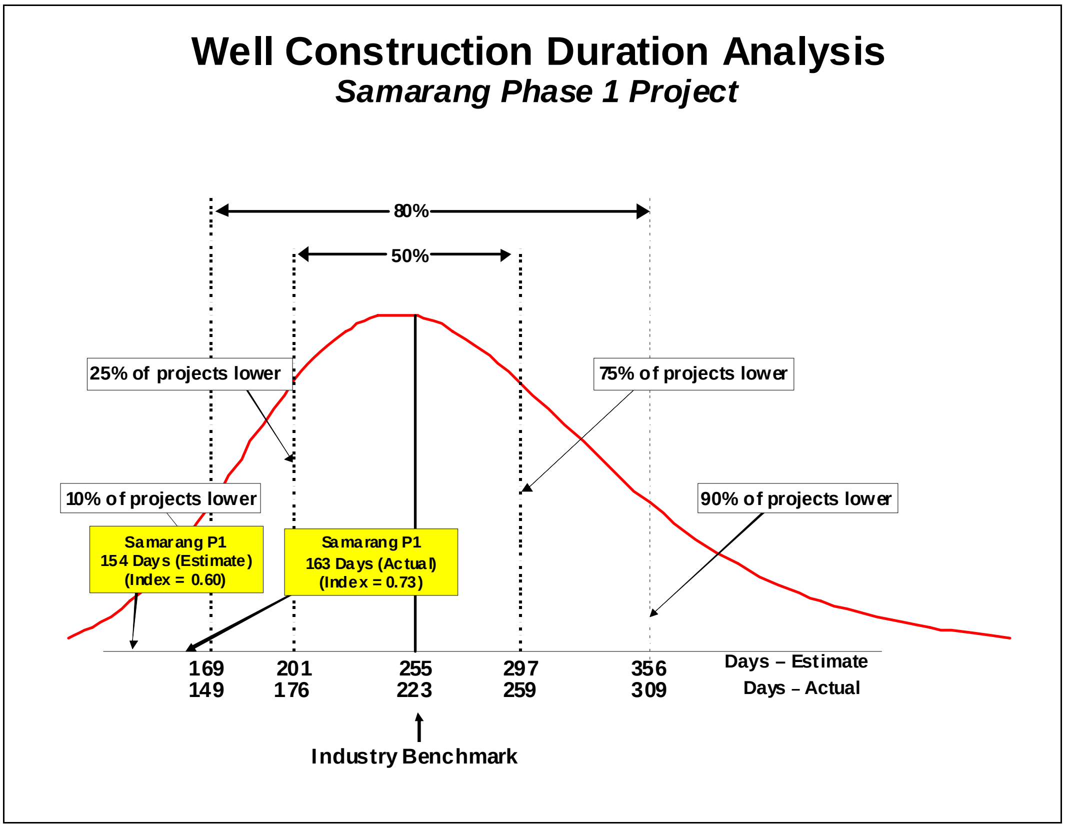

Figure 9

As shown in Figure 9, the planned total well construction duration of the Samarang Phase 1 Project was 154 days, which is 40 percent faster than the industry benchmark for similar scope. The actual well construction duration was 163 days, which is 27 percent faster than Industry. We added 22 days to the schedule benchmark to account for of the time for P&A and casing repair in the B-66 well.

PCSB has an average Well Construction Duration Index of 0.80, or 20 percent faster than industry. The Samarang well construction program was better than the PCSB average, and quite fast, especially if we consider the wells complexity and the scope that was new to PCSB. The difference in the estimate and actual benchmarks reflect the change in wells execution strategy. At authorisation, the team planned to construct the wells sequentially; the benchmarks reflect this approach. In execution, the team constructed the SMJT-B well sequentially but decided to construct the SMJT-F wells batch-wise to shorten the durations. The benchmark takes this factor into consideration and hence is shorter.

The Well Construction Duration Model determines the industry average well construction duration using inputs from two separate models: a Well Drilling Duration Model and a Well Completion Duration Model. The Drilling Duration Model takes into consideration drilled footage, complexity of casing design, well path complexity, and batch drilling. The Well Completion Duration model considers completion depth, tree type complexity, batch drilling and completion complexity (multizone, multilateral, sand control, etc.).

At the time of the prospective evaluation of the Samarang Phase 1 Project, the well construction duration benchmark provided was 108 days. The change in benchmark is due to an update in the model since that time. The previous model predicted wells program durations by comparing overall program characteristics such as number of wells, number of re-used wells and average wells complexity. The updated model predicts drilling and completion durations for each well. The drivers of these durations are described above. To get the total wells program duration, the individual well durations are summed up. The new models also incorporate more recent projects.

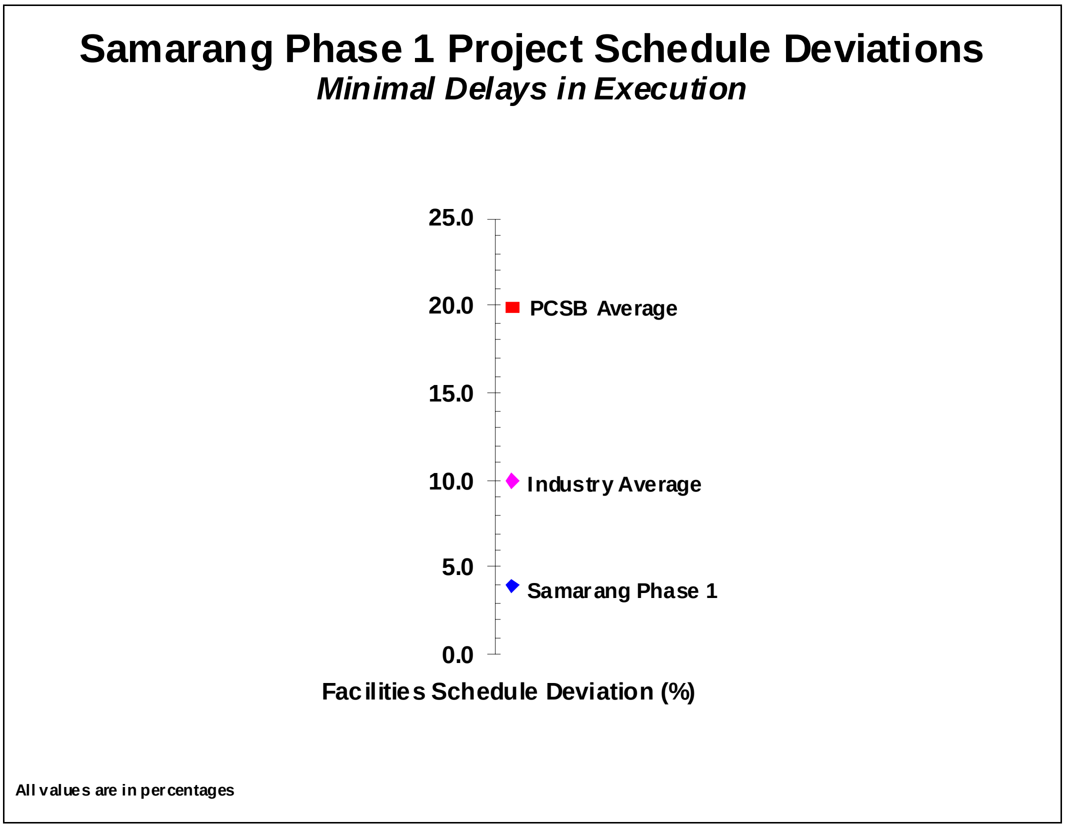

Figure 10

As shown in Figure 10, the facilities schedule deviation is 4 percent of the planned execution duration. The PCSB average deviation is 20 percent. The deviations are measured based on the difference in the actual duration versus the target durations that were agreed at the time of the project's authorisation.

The predictability of the Samarang Phase 1 Project was far better than previous PCSB projects, and in the case of the facilities, better than Industry as well. Strong practices and execution discipline were key drivers of this performance.

PROJECT DRIVERS

IPA developed a suite of metrics to evaluate project practices and drivers. Table 8 presents the metrics for the Samarang Phase 1 Project's drivers and asset development practices. For detailed descriptions of the ratings indicated below, please refer to IPA's prospective evaluation of April 2010.

Table 8
Summary of Project Practices and Drivers for the Samarang Phase 1 Project
(At Authorisation in April 2010)

Driver or Practice	Samarang Phase 1 Project	PCSB Average	Industry Average	Best Practice
Appraisal Strategy	*Conservative*	*Conservative: 75%* *Moderate:25%* *Aggressive: 0%*	*Conservative: 40%* *Moderate: 37%* *Aggressive: 23%*	Not Applicable
Reservoir Complexity Index	52	39	39	Not Applicable
Wells Complexity Index	44	49	59	Not Applicable
FEL Index – Asset	4.26 (*Best*)	7.19 (*Poor*)	6.37	4.00 to 5.50
- Reservoir FEL	3.85 (*Best*)	6.45 (*Fair*)	5.77	4.50 to 5.50
- Wells FEL	5.72 (*Best Practical*)	6.59	6.14	5.00 to 6.00
- Facilities FEL (Offshore)	3.95 (*Best*)	8.05 (*Poor*)	7.04	4.00 to 4.75
Team Development Index (TDI)	3.00 (*Fair*)	2.79 (*Fair*)	2.88	*Good*
Team Integration	Not Integrated	50 percent of projects Integrated	59 percent of projects Integrated	Yes
Integration of Operations With Project Team	No	75 percent of projects Integrated	81 percent of projects Integrated	Yes
Facilities Technical Innovation	*Conventional*	*Conventional: 83%* *Moderate: 17%* *Substantial: 0%*	*Conventional: 69%* *Moderate: 28%* *Substantial: 3%*	Not Applicable
Wells Technical Innovation	*Conventional*	*Conventional: 63%* *Moderate: 38%* *Substantial: 0%*	*Conventional: 57%* *Moderate: 40%* *Substantial: 4%*	Not Applicable
Facilities VIPs Used	0 percent	0 percent	10 percent	40 to 60 percent
Subsurface VIPs Used	66 percent	0 percent	6 percent	

PROJECT EXECUTION DISCIPLINE

Summary

IPA evaluates execution discipline, which comprises several key factors that play a role in successful project execution. IPA evaluates project control as measured by the Project Control Index (PCI); the incidence of key team member turnover; and the frequency and effect of major late changes. Table 9 summarises the project execution discipline for the Samarang Phase 1 Project. The Samarang Phase 1 Project used control plans that were better than both Industry and PCSB averages. The project had no major changes in the wells or the facilities scope. There were no project manager turnovers.

Table 9
Summary of the Samarang Project Phase 1 Execution Discipline

Project Execution Discipline	Samarang Phase 1 Project	Industry Average	PETRONAS Average	Best Practice
Project Control Index (PCI)	*Good*	*Poor*	*Poor*	*Good*
Project Manager Turnover	No	42 percent of projects	None	No
Major Late Changes	No	83 percent of projects	75 percent of projects	No

Details

Project Control Index

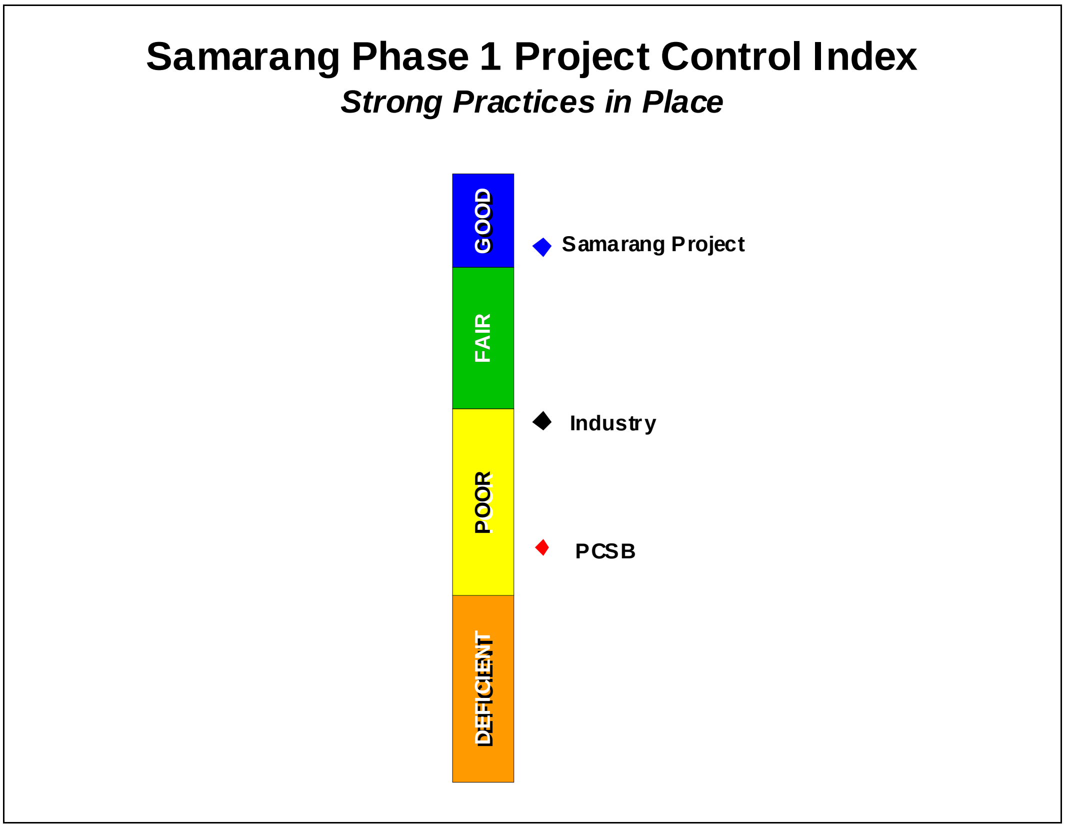

Figure 11

Figure 11 illustrates that the Samarang Phase 1 Project had a *Good* Project Control Index (PCI), which is better than the industry average as well as the PCSB average. IPA research shows that projects with strong project cost and schedule control practices have less cost growth and schedule slip, and fewer late changes. During project definition, project control supports the achievement of *Best Practical* FEL by establishing effective cost and schedule control baselines. During execution, 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.

The PCI includes two components: (1) estimating for control and (2) control during execution. Below we discuss the status of each component for the Samarang Phase 1 Project.

- **Estimating for Control:** This element of the PCI measures how definitive project estimating methods were and how the estimate quality and effectiveness were validated. We found that the Samarang Phase 1 Project's estimating methods were sufficiently definitive for all cost categories to support effective project control. The project estimate was integrated with the project schedule. The estimate basis document was published. The estimate was consistent with the latest design documents. Facilities and drilling estimates were based on the same scope and concepts. The estimate was quantitatively validated by an in-house estimating specialist using in-house 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. It also includes whether cost data were captured in a database for future planning. The Samarang Phase 1 Project used comprehensive physical progressing methods during execution. Most work breakdown structure (WBS) activities had physical measures associated with them. Project management reviewed detailed progress updates. Project status/progress reports were prepared on a weekly basis at a summary and detailed level. All elements of execution were covered in the report (engineering, fabrication, transportation and installation, hook-up and commissioning, and drilling). The reports covered both cost and schedule. Progress reports covered the overall progress of the project. An owner project control specialist was assigned to the project and was actively involved. Finally, detailed project cost data were captured in an owner database for future planning.

The Samarang Phase 1 Project followed other practices that drove effective project control. The project manager and senior team members conducted regular meetings armed with earned value/cost analysis and ensured that team members understood the project status well and its direction at any time. Similarly, they interacted with the contractor's team and made sure that the contractor followed the earned value analysis along with the schedule and resource analysis. Monthly/weekly updates of all the analysis were posted on a notice board for team awareness. Monthly offshore health safety & environment (HSE) management visits were done during drilling, hook-up, and commissioning (HUC). These practices helped to resolve any outstanding issues at the worksite. Daily meetings were held at the office and offshore during drilling operations.

Late Changes and Team Turnover

No major changes occurred during project execution. There were minor modifications in the drilling and completion plan to meet the PCSB production requirements, which helped the team to achieve first oil earlier than planned. No senior person left the project during execution except the head of facilities, who left after completion of drilling activities. A new head of subsurface was selected from among the team, and no issues arose due to this turnover.

LESSONS LEARNED

Based on our analysis of historical industry performance and our assessment of the Samarang Phase 1 Project, we present the following key lessons for future projects executed by PCSB

1. *Combining good FEL with strong project controls helps prevent design changes in execution.* Using the PETRONAS project process, the PPMS, to guide its work, the team achieved optimal FEL prior to authorisation. The team followed through with good project controls. Together, these practices enabled the team to avoid design changes in execution. By contrast, 75 percent of recent PCSB projects have experienced late design changes.

2. *Sufficient team resources in FEL and execution help drive project success.* The Samarang Phase 1 Project team was fully staffed in both definition and execution, which drove strong, comprehensive planning. There were no disruptive turnovers during the project's execution, allowing team members to follow through with the plans they had put in place prior to authorisation.

3. *Lack of operations input in design raises the risk of problems at handover*. The main gap in the Samarang Phase 1 Project's practices was the lack of operations integration in the team. The effect of this was not seen until handover of the extension deck of the SMJT-F platform. Any difficulties or deviations from plan for the Samarang Phase 1 Project could easily have had far greater cost and schedule implications if the facilities scope had been larger.

APPENDIX A: COST AND SCHEDULE

PROJECT COST DISTRIBUTION

Table 10 summarises the estimated and actual costs for the Samarang Phase 1 Project using the project team's cost breakdown. All costs are in US$ million. The exchange rate used between the Malaysian ringgit and US dollar was 3.1. The detailed engineering cost of facilities was obtained from estimate cost. The project management cost has been allocated equally between the facilities and well programme costs.

Table 10
Cost Distribution for the Samarang Phase 1 Project ($US million)

Cost Category	**Total Project Estimate at Authorisation (^{2010}\$US million)**	**Total Project Actual Cost ($US million)**
Facilities		
Front-End Engineering	0.00	0.00
Detailed Engineering	3.92	3.92
Project Management	11.15	7.37
Fabrication/Material/Equipment	4.63	4.53
Tow, Integration, Transport, Installation	17.38	4.82
Hook-up and Commissioning	2.14	3.28
Other Project Costs	0.27	0.00
Contingency	0.00	Not applicable
Total Facilities Costs	**39.49**	**23.92**
Well Construction		
Project Management	10.01	7.37
Detailed Well Planning	0.00	0.00
Non-Well Activities	4.55	11.89
Xmas Tree	2.61	2.09
Drilling	27.46	42.45
Formation Evaluation & Completions	38.54	30.87
Well Clean up & Suspension Activities	0.00	0.00
Other Project Costs	0.07	0.07
Contingency	10.09	Not applicable
Total Well Program Costs	**93.34**	**94.74**
Total Facilities and Well Program Costs	**132.82**	**118.66**

PROJECT SCHEDULE

Table 11 summarises the schedule of the Samarang Phase 1 Project. The planned execution schedule was 28.5 months. The actual execution time was 29.5 months. First production was planned for 20 October 2011, and was achieved on 17 August 2011.

Table 11
Schedule for the Samarang Phase 1 Project

Project Phase/Activity	Planned Schedule			Actual Schedule		
	Start	Finished	Months	Start	Finished	Months
FEL 2 – Project Select	2-Jan-05	31-Mar-05	2.9	2-Jan-05	31-Mar-05	2.9
FEL 3 – Define / Detailed Engineering	4-Jun-09	31-Dec-09	6.9	4-Jun-09	31-Dec-09	6.9
Authorisation Process	1-Apr-10	15-Apr-10	0.5	1-Apr-10	15-Apr-10	0.5
Authorisation Date	15-Apr-10			15-Apr-10		
HUC Bidding	22-Mar-10	16-Apr-10	0.8	22-Mar-10	16-Apr-10	0.8
Award HUC contract	3-Jul-10	3-Jul-10	0.0	11-Jun-10	11-Jun-10	0.0
Procurement	12-Mar-10	19-Nov-10	8.3	3-Oct-09	20-Apr-11	18.5
Fabrication	29-Nov-10	3-Feb-11	2.2	13-Aug-10	18-Dec-10	4.2
Offshore Execution	12-Apr-08	2-Jun-09	13.7	1-Jan-11	15-Nov-11	10.5
Drilling						
Detailed Well Planning	15-Feb-10	26-Mar-10	1.3	7-Jun-10	31-May-11	11.8
Development Drilling	4-May-11	10-Oct-11	5.2	16-May-11	6-Nov-11	5.7
SMJT-F (4 wells)	4-May-11	3-Sep-11	4.0			
SMDP-B (1 well)	6-Sep-11	10-Oct-11	1.1			
First Hydrocarbons	20-Oct-11			17-Aug-2011		
Execution (DE to Completion of HUC, w/o the waiting period to complete drilling[16])	4-Jun-09	19-Oct-11	23.1	4-Jun-09	15-Nov-11	24.1
Execution (Fabrication to Completion of HUC)	29-Nov-10	19-Oct-11	10.7	13-Aug-10	15-Nov-11	15.1
Cycle Time	4-Jun-09	19-Oct-11	23.1	4-Jun-09	15-Nov-11	24.1

[16] No HUC work was done during the drilling period from 16 May 2011 to 29 October 2011 (5.4 months). So this time has been subtracted from the execution time. Similarly 5.4 months has been deducted from the planned execution schedule.

APPENDIX B: PROJECT TEAM'S LESSONS LEARNED

Project Management

- Making sure contractors and subcontractors are paid on time helps prevent delays.
- Using a project dashboard to note project status is an effective management tool.
- Having a good team member handover plan prevents disruption to project.
- Having a WBS dictionary helps project cost and schedule planning.

Facilities

- Sharing crew boats with the drilling function may reduce hookup and commissioning productivity, as facilities team cannot decide transport timings.
- Developing SIPROD (Simultaneous Production and Drilling) plans and heavy-lift plans help ensure smooth execution.

Drilling

- Having a workshop to determine drilling decision flow for decisions in the field helped efficiency.
- It is much easier to use new slots than reusing slots on platform, as discovered during the drilling of the B-66 well.
- Effort spent on contingency planning for corroded casing in B-66 wells paid off, as the team had the materials and equipment on hand.

Subsurface

- Extending uncertainty modelling to p10 and p90 estimate helps develop a more robust geological model.
- Having more well site geologists helps collect and convey important reservoir information.
- Having geophysicists look at real-time imaging and logs helps fault identification and wells targeting.
- Obtaining involvement of operations geologists and petrophysicists 1 to 2 months before drilling helps data-gathering operations.

APPENDIX C: TEAM DEVELOPMENT INDEX

The Team Development Index (TDI) measures the processes that enhance team performance, improve project definition, increase VIPs use, and drive project outcomes. Strong team development supports *Best Practical* Front-End Loading (FEL). It is virtually impossible for projects with poor 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. IPA research shows that team development drives safety results, cost performance, execution schedules, and operational performance more than other key drivers of project outcomes.[17] In other words, when FEL is poor, good team development improves project outcomes. When FEL is average, good team development drives better project outcomes than average or poor 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/Risk Analysis:*** 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 risks have been identified and mitigation plans developed.
- ***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.

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