REVISED FINAL

A CLOSEOUT EVALUATION OF THE SAMARANG PHASE 2 ACCELERATED DEVELOPMENT PROJECT

Prepared for
PETRONAS

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PREFACE

This IPA report summarizes the performance of PETRONAS's Samarang Phase 2 Accelerated Development (SMRG 2 AD) Project.

This closeout evaluation of the SMRG 2 AD Project compares the project's actual performance with the performance planned at project authorization. Comparison is also made with other similar, completed projects in Industry and with PERONAS's average performance. 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. It should be noted that this closeout evaluation is conducted when the SMRG 2 AD Project just completed and only provisional production data was available. Therefore, we do not evaluate the production attainment outcome. When we receive the final production attainment, we will follow up with a second closeout evaluation.

This report establishes final benchmarks for the SMRG 2 AD Project, which was originally reviewed as part of the Samarang Phase 2 (SMRG 2) Project for PETRONAS in December 2011.[1] *Please refer to that report for the original benchmarks for the drivers of the SMRG 2 AD Project*; we will not repeat those benchmarks in this study. These final benchmarks will be used to characterize the SMRG 2 AD Project's performance in PETRONAS's UIBC metrics.

To supply industry benchmarks, we used IPA's Upstream Project Evaluation System (PES®).[2] The Upstream PES Database contains information on more than 1,300 projects conducted by more than 40 companies over the past 25 years.

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

- *Project Drivers*
- *Project Execution Discipline*
- *Project Outcomes*

Members of the project team supplied the information for this analysis in meetings held on 30 July 2013 and 31 July 2013, in the project offices in Kuala Lumpur, Malaysia. Project team members present at these meetings included Andrey Goloboredko (Reservoir Engineer), Aurelian Serban (PTech), Gabriel Lica (QA & Safety Manager), Zuraidah Khairudian (DCM), Nor Suraya Suaid (Project Control), Tomaso Ceccarelli (Completions), Prashanth Nair (Reservoir Engineer), Jorge Maldonado (Reservoir Engineer), Johann Osorio (Asset Planner), Aimran Abd Hamid (Cost Control Engineer), Mohd Shahrizan Ahman (Lead Planner), Sarah Harris (Head of Facilities), Yopy Sosiawan Amrizal (Project Engineer), and Kandasamy Selvakumar (HUC Lead).

Khanh Nguyen and Erick Kowa 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 Khanh Nguyen of IPA Singapore at +65 6567 2201 or knguyen@ipaglobal.com.

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[1] Khanh Nguyen and Galvin Singh, *A Prospective Evaluation of the Samarang Phase 2 Project*, IPA, PET-1214-PRO, December 2011.
[2] PES is a registered trademark of IPA.

TABLE OF CONTENTS

KEY MESSAGE

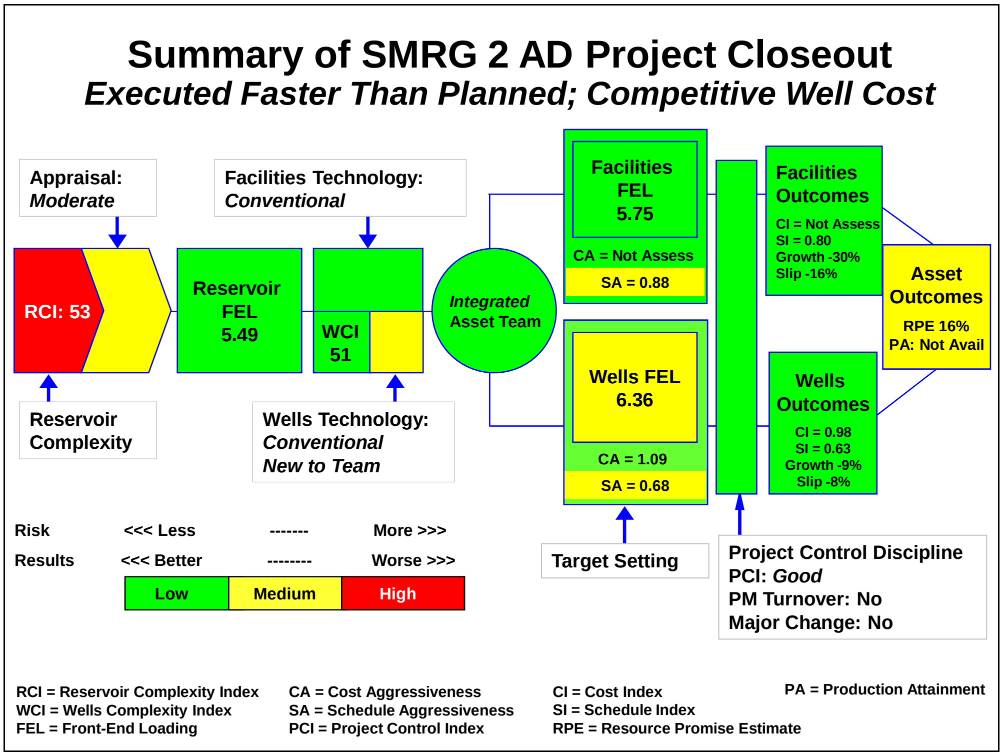

Figure 1

The Samarang Phase 2 AD Project team rose to the challenge presented by the management and successfully delivered the project faster than planned and with competitive well cost. With an aggressive first oil target, the team faced various challenges in project execution planning. In addition, the use of slot recovery introduced technology risks. Recognized challenges and risks, the team put in place mitigation plans to manage risks and identified opportunities to save cost and schedule. The project has industry average or better definition in all areas; team was integrated and use strong execution discipline throughout execution. However, uncertainties in the appraisal strategy led to an unpredictable result, despite a moderate upgrade in the resource promise estimate[3].

To meet its aggressive schedule target, the Samarang Phase 2 AD Project was executed with some deviations from PETRONAS's project management system. Therefore, even though the success of Samarang Phase 2 AD Project presents some positive learnings for future projects, the use of similar practices should be carefully considered because it may present great risks, particularly for larger scale and more complex developments. For the Samarang Phase 2 AD, these practices were justified because the project scope was relatively small and not highly complex. In addition, Samarang Phase 2 AD Project risks were well identified and plans were in place to mitigate these risks.

[3] Production attainment outcome was not assessed in this evaluation because only provisional production data was available. When final production attainment data is obtained, IPA will follow up with a second closeout evaluation.

PROJECT OVERVIEW

SUMMARY

The Samarang Phase 2 Accelerated Development (SMRG 2 AD) Project is an accelerated drilling program over the original field development plan for the Samarang Phase 2 (SMRG 2) Project drilling program. The SMRG 2 AD Project main objective was to accelerate development under the Petroleum Management Unit (PMU) Crude Oil Initiative (COIN) 2012 Program. Its specific objectives included: (1) to achieve first oil in Q4 2012 (however, the team committed to management first oil in Q1 2013); and (2) to produce a total of 2.2 million barrels (MMbbl) of oil by 2020 and at a stabilized production rate of 1,050 barrels of oil per day (bopd) from three infill drilling wells.

The SMRG 2 AD Project was initiated in response to a challenge presented by PMU: consider opportunities for accelerating oil production to meet high domestic demand coupled with shortage in supply due to Sudan political instability. By accepting the challenge, the team faced with aggressive first oil target. This led to various challenges in execution planning, particularly in procurement of long-lead items and securing an available and suitable rig. In addition, the use of shallow water slot recovery which had never been executed in PETRONAS Carigali Sdn Bhd (PCSB) before introduced technology risks.

The SMRG 2 AD Project achieved first oil on 22 December 2012, in line with the team's target and nearly 2 months earlier than the date committed to management (26 February 2013). The actual resource promise estimate (RPE) by 2020 is 2.51 MMbbl, which is 16 percent higher than the target of 2.17 MMbbl. The project was executed with competitive well cost. The project was executed at a cost of RM174 million, nearly 15 percent less than estimated cost of RM207 million. This underrun was contributed by both offshore revamp (30 percent) and wells (9 percent) after adjusting for escalation and the currency exchange rate.

PROJECT BACKGROUND

The Samarang field is located in the South China Sea off the coast of Sabah, East Malaysia, about 72 km northwest of the Labuan Gas terminal. Due to the aging infrastructure and declining production, the field was forecast to become uneconomic by 2017 if no further development effort was undertaken. In April 2009, the proposed field redevelopment concept involving infill drilling and enhanced oil recovery (EOR) was endorsed by the management. The scope of work was conducted by PCSB and Schlumberger (SLB) Oilfield Services. The project was split into two phases. Phase 1 included infill drilling of 5 wells and Phase 2 consisted of the EOR scope and the remaining 11 infill wells. The Samarang Phase 1 (SMRG 1) Project was completed in November 2011. The SMRG 2 Project was to be implemented as SMRG 2 EOR and SMRG 2 Infill. The team committed to management with first oil from SMRG 2 Infill to be achieved in January 2014 (team target was June 2013).

In 2011, PMU challenged PCSB to consider opportunities for accelerating oil production under the COIN 2012 Program by achieving first oil on Q4 2012, 12 months earlier than planned for SMRG 2 Infill. This challenge aimed to meet high domestic demand coupled with shortage in supply due to Sudan political instability. However, no production quota was specified for assets contributing to the accelerated production. It rather depended on different assets and projects to identify the opportunity and accept the challenge. The Samarang team identified opportunity within its SMRG 2 Infill to accelerate production. This included available recoverable 2 well slots in platforms SMJT-F and one well empty slot on SMJT-G, and work requirements for platform readiness. Furthermore, during drilling of the SMRG 1 Project, additional opportunities were identified in the SM-F97 well but they could not be capitalized on because of cased-hole completion limitations. This promising discovery was also considered for acceleration. In December 2011, Samarang Alliance Board gave Samarang project management team (PMT) a green light to pursue the acceleration. The SMRG 2 AD Project was initiated with scope including 2 wells from SMRG 2 Infill and an additional well to capture the opportunities identified in SMRG 1 Project. However, recognizing the challenges of acceleration, the team committed to the management first oil in Q1 2013 (P80) but set Q4 2012 (P50) as team internal target.

In January 2012, an integrated review workshop was held with stakeholders including PMU, Sabah operations, and project disciplines. The objective of this workshop was to align on project objectives, present key challenges/risks to overcome, and get buy-in and support from PMU. The SMRG 2 AD Project was registered in the PMU COIN Program to have PMU support as well as to give the project priority in technical/project reviews and gates. The SMRG 2 AD Project was approved to combine a series of reviews in one session as an exception from the standard PETRONAS Process Management System (PPMS) process.

PROJECT HISTORY

The SMRG 2 AD Project was sanctioned on 19 June 2012. Wells SM-84ST1 and SM-101 were sanctioned earlier on 4 April 2012 as part of the SMRG 2 Project. The additional well SM-82ST2 was sanctioned on 19 June 2012, the same date as for the overall SMRG 2 AD Project.

From August to September 2012, subsurface optimization work was carried out with review of well logs, cores, and results of Phase 1 drilling. The optimization work resulted in slight changes in the final well positions and revisions of the geological/structural model by repositioning fault positions. The static model had a small change in volume with new faults and structure information but the hydrocarbon properties remain the same. Wells drilled in the SMRG 2 AD Project provide data to be incorporated into further revisions of reservoir models. It is expected that static and dynamic models will be revised (starting in October 2013 and finishing in November 2013) based on newer acquired 3D seismic.

The front-end engineering design (FEED) contract with MMC for the SMRG 2 Project platform modification scope was completed in 2011, except for the I/O scope. To fast track the process of procuring a new contract, FEED and detailed engineering for the SMRG 2 AD Project were issued as change orders to the SMRG 2 Project’s I/O scope. Re-AFC for the SMRG 2 AD Project started in May 2012 and was completed in August 2012. A hook-up and commissioning (HUC) work order was issued in July 2012.

To ensure on time delivery of long-lead items (LLIs) on site, team sought for advanced funding to procure some drilling, completion and facilities LLIs. An advanced funding of RM19.71 million was approved by PCSB management in March 2012 prior to project sanction. This included RM18.11 million for drilling materials and equipment; and RM1.60 million for facilities.

Platform SMJT-G was ready on 27 October 2012. During execution, to expedite well tie-ins, HUC activities were concurrent with completion in order to utilize rig facilities. Samarang PMT visited the rig and presented to operation installation manager and company site rep the plans for concurrent work. PMT received the support to have bed space and workshop space to carry out the facilities work on the rig. As a result, expedite well tie-ins were achievable. Active communication and engagement with the drilling team was planned and executed to ensure the concurrent activities ran smoothly. To mitigate the HUC contractor risk, a weekly contractor meeting was held during which the contractor issued all required documents before any execution took place. Three team members were present in the Labuan yard to monitor and track work (this was one of the lessons learned from the Bokor Project and the SMRG 1 Project, in which the HUC contractor had also participated).

The result was that no work was carried over. Active contractor management was also used during offshore execution.

For the infill drilling scope, well detailed design was completed in October 2012. Well SM-82ST2 was planned to spud first and to be batch drilled with well SM-84ST1. This plan was based on the fact that less work would be required for platform SMJT-F due to the existing simultaneous production and drilling (SIPROD) facilities[4]. However, during execution, two months prior to rig entry, based on economic analysis and outcomes, it was decided that no SIPROD was required for SMJT-G. As a result, well SM-101 was spudded first so that first oil could be achieved earlier. There were no major issues during well execution that led to significant delays or cost overruns. Washout, a known issue in Samarang and experienced during the SMRG 1 Project, occurred in SM-101 and SM-82ST2. For well SM-84ST1, sand G9.0 could not be completed due to borehole conditions. Most non-productive time (NPT) was due to waiting on weather.

The risks in well execution included the lack of confirmation of rig availability and LLIs for completion equipment were ordered without an approved contract in place. The team planned to use the rig *Naga-3* (US$142,000 per day); however, its availability was not confirmed. The team actively liaised with the Project Planning and Control Department (DPP) and also sourced through an alliance partner to secure a rig. A monthly meeting was held to track rig availability in the PETRONAS master integrated schedule (this schedule includes 15 rigs). Jack-up rig *Maersk Convincer* (rig rate of US$143,700 per day) availability was confirmed in November 2012, one month before spud date. However, even without rig confirmation, the rig *Maersk Convincer* was inspected during the planning stage as a potential candidate and its rig movement was reviewed by the Drilling Review Committee (DRC). For the procurement of LLIs for completion equipment, LLIs were order based on Letter Of Award despite an existing contract with SLB was expired and contract extension was not yet approved. To minimize the risk of not having the contract extended, SLB provided competitive equipment price based on SMRG 1 Project.

Under the COIN 2012 Program, first oil was targeted for December 2012. However, the team identified the challenges to meet this target and committed to first oil in Q1 2013 (P80) with an internal target of December 2012 (P50). First oil was achieved on 22 December 2012, 2 months earlier than the date committed to PMU.

PROJECT SCOPE AND TECHNOLOGY

The SMRG 2 AD Project scope included three infill drilling wells (SM-82ST2, SM-84ST1, and SM-101) and associated platform modifications. SM-84ST1 and SM-101 were the two wells that were planned to be completed in the SMRG 2 Infill . SM-82-ST2 was the additional well identified as a result of the SMRG 1 Project drilling. However, the well design is similar to the other two wells. All three wells are single string, multizone open-hole completion with zone isolated using swellable packers. The three wells target shallow sands.[5] SM-82ST2 and SM-84ST1 were batch drilled and completed from platform SMJT-F through slot recovery, and SM-101 was drilled and completed from platform SMJT-G through an empty slot. Open-hole completions with standalone screens, swell packers, and shallow water slot recovery are conventional for Industry but new to Samarang. Team identified technology risks and developed detailed execution plan to mitigate risks.

For the offshore revamp scope, platform modifications for platform SMJT-F and SMJT-G were also part of the SMRG 2 Project. However, there were some changes specific

[4] Workover was completed and SIPROD facilities could be utilized. This opportunity was identified as a result of close coordination between project team and the Workover and Sabah Operations team (SBO).
[5] SM-82ST2 targeted sands G and H. SM-84ST1 targeted sands F and H. SM-101 targeted sands J and K. SM-82ST2 was planned with four zones and completed with seven zones. SM-84ST1 was planned with four zones and completed with six zones.

to the SMRG 2 AD Project. For example, there were two well tie-ins for the SMJT-F platform instead of one; for the SMJT-G platform, deck extension was no longer required because of the use of single completion for one well instead of dual completion for two wells. SIPROD was planned but during execution SIPROD was not required for SMJT-G platform. In summary, the tie-in scope for the SMRG 2 AD Project included:

- SMJT-F Platform
  - Flowline tie-in at production header. This included isolation work on one of the flowlines and minor adjustments to suit the new double block and bleed (DBB) length at the header
  - Gas lift tie-in at the gas lift header including minor adjustments for the new DBB at the header
  - Utilize well head control (WHC) panel module spares from SMRG 1
- SMJT-G Platform[6]
  - Install new flowline and gas lift line tie-in to empty connection on the headers
  - Refurbish unused WHC module for the new well

CONTRACTING STRATEGY

MMC Oil and Gas completed FEED and detailed engineering under a lump sum contract. Construction was reimbursable and HUC was lump sum, both to Carimin Engineer and Services Sdn Bhd. Carimin was not an A player but was selected because it is part of the umbrella contract for the Sabah region. The HUC work order was issued in July 2012.

BASIS OF COMPARISON

In this report, we use IPA's Upstream Database to compare the SMRG 2 AD Project with a number of similar industry projects. The Upstream Database contains more than 1,300 recent projects. We used a set of recent projects to establish industry benchmarks for the SMRG 2 AD Project drivers. Table 1 outlines the characteristics of this set.

To benchmark the SMRG 2 AD Project's estimated and actual cost and schedule, we used IPA models, including the Well Construction Model for the well construction program and the Offshore Time of Engineering and Construction (TEC) Model, to benchmark the execution duration. The characteristics of the datasets used to develop these models are summarized in Table 2 and Table 3. The SMRG 2 AD Project's wells program characteristics and offshore revamp cost (used to benchmark its execution duration) lie within the range of our model datasets and are therefore amenable to benchmarking.

[6] The SMRG 2 Project scope included two wells on SMJT-G with dual completions (i.e., four lines). However, in the SMRG 2 AD Project, only one well with a single line was planned. As a result, there was only one new line and no deck extension was required.

Table 1
Characteristics of Recent Subset of Upstream Projects

Characteristic	SMRG 2 AD Project	Dataset (404 Projects)		
		Minimum	Median	Maximum
Year of Sanction	2012	2004	2007	2012
Region	Asia	Asia, 23%; N America, 16%; Europe, 19%; Africa, 13%; S America, 13%; Oceania, 7%; Others, 9%		
Actual Asset Cost (2003 US$ million)	38	< 10	143	>3,000
Water Depth (m)	10	<20	150	>3,000
Facilities Concept	Offshore Revamp	Offshore Revamp, 11%; Others, 89%		

Table 2
Characteristics of the Well Construction Component Model Dataset

Characteristic	SMRG 2 AD Project	Dataset (78 projects)		
		Minimum	Median	Maximum
Year of Sanction	2012	1997	2004	2008
Total Actual Cost (2003 US$ million)	31	2	66	700
Region	Asia	Asia, 16%; N America, 19%; S America, 9%; Europe, 33%; Africa, 13%; Oceania 10%		
Program Duration (Days)	76	12	240	>2000

Table 3
Characteristics of the Offshore TEC Model Dataset

Characteristic	SMRG 2 AD Project	Dataset (259 projects)		
		Minimum	Median	Maximum
Year of Sanction	2012	1989	2000	2008
Region	Asia	Asia, 15%; GoM, 19%; S America, 11%; Europe, 35%; Africa, 11%; Other, 9%		
Total Actual Cost (2003 US$ million)	7	6	186	>4,500
Offshore Revamp (%)	100	0	0	100
Installation Window (Months)	12	4	12	12

PROJECT BENCHMARKS

PROJECT OUTCOMES

Table 4, Table 5, and Table 6 summarize the estimated and actual outcomes for the SMRG 2 AD Project's cost, schedule, and RPE. Industry and PETRONAS benchmarks are presented for comparison.

Table 4
Summary of the Cost Outcome Metrics for the SMRG 2 AD Project

Outcome Metric	SRMG 2 AD Project		Industry Average	PETRONAS
	Estimated at Sanction	Actual		
Well Component Cost Effectiveness – Money of Day (MOD) in RM Million				
Wells (Index)	149 (1.09)	134 (0.98)	137 (1.00)	(0.79)
Cost Deviation				
Asset	Not Applicable	–15 percent	6 percent	4 percent
Facilities	Not Applicable	–30 percent	5 percent	17 percent
Wells	Not Applicable	–9 percent	6 percent	2 percent

Offshore revamp cost was not benchmarked because its scope is outside IPA Offshore Revamp Model range.

As shown by Table 4, the project's targeted wells cost was 9 percent higher than Industry but actual cost was in line with Industry[7]. Facilities underran its cost by 30 percent and wells by 9 percent, for an overall asset cost underrun of 15 percent.

Table 5
Summary of the Schedule Outcome Metrics for the SMRG 2 AD Project

Outcome Metric	SMRG 2 AD Project		Industry Average	PETRONAS
	Planned at Sanction	Actual		
Schedule Effectiveness				
Facilities Execution in Months (Index)	12.4 (0.88)		14.0 (1.00)	(0.86)
		10.4 (0.80)	13.0 (1.00)	(0.99)
Well Construction in Days (Index)	94 (0.68)	87 (0.63)	139 (1.00)	(0.72)
Schedule Deviation				
Facilities Execution	Not Applicable	–16 percent	14 percent	19 percent
Well Construction	Not Applicable	–8 percent	Not Available	

As shown in Table 5, the SMRG 2 AD Project's actual offshore revamp execution duration was 20 percent faster than Industry and 16 percent faster than planned. The actual well construction duration was 37 percent faster than Industry[8] and 8 percent faster than planned.

[7] Industry average was adjusted to include P&A and slot recovery costs of RM8.0 million for estimate and RM8.6 million for actual.
[8] Industry average was adjusted to include 10 days of P&A and slot recovery.

Wells Execution Outcomes

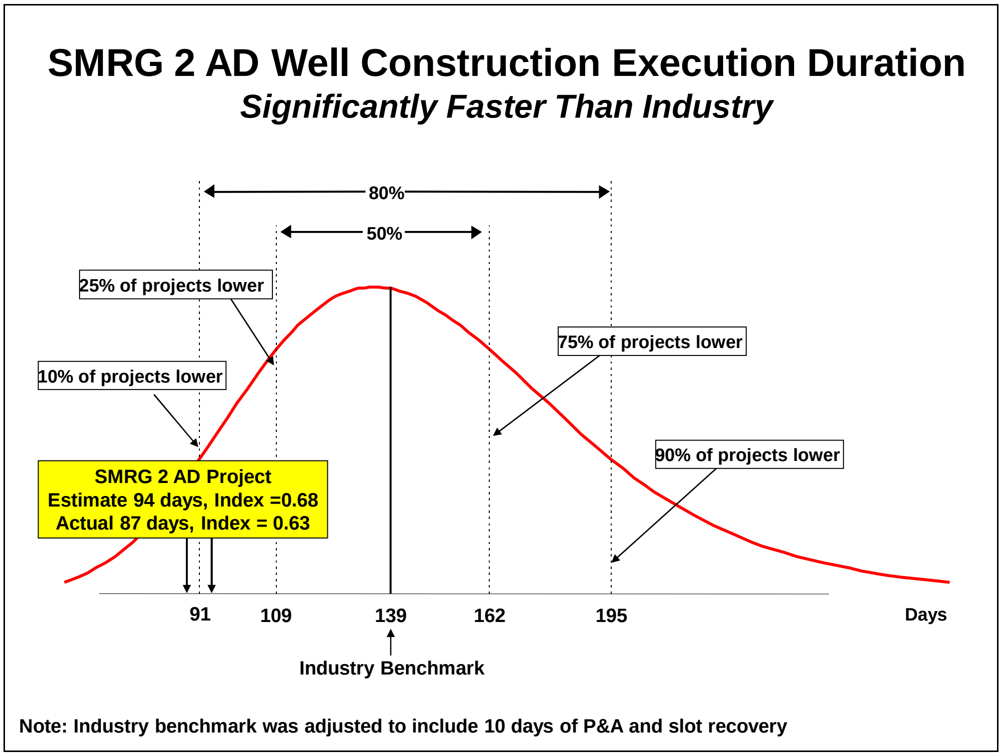

Figure 2

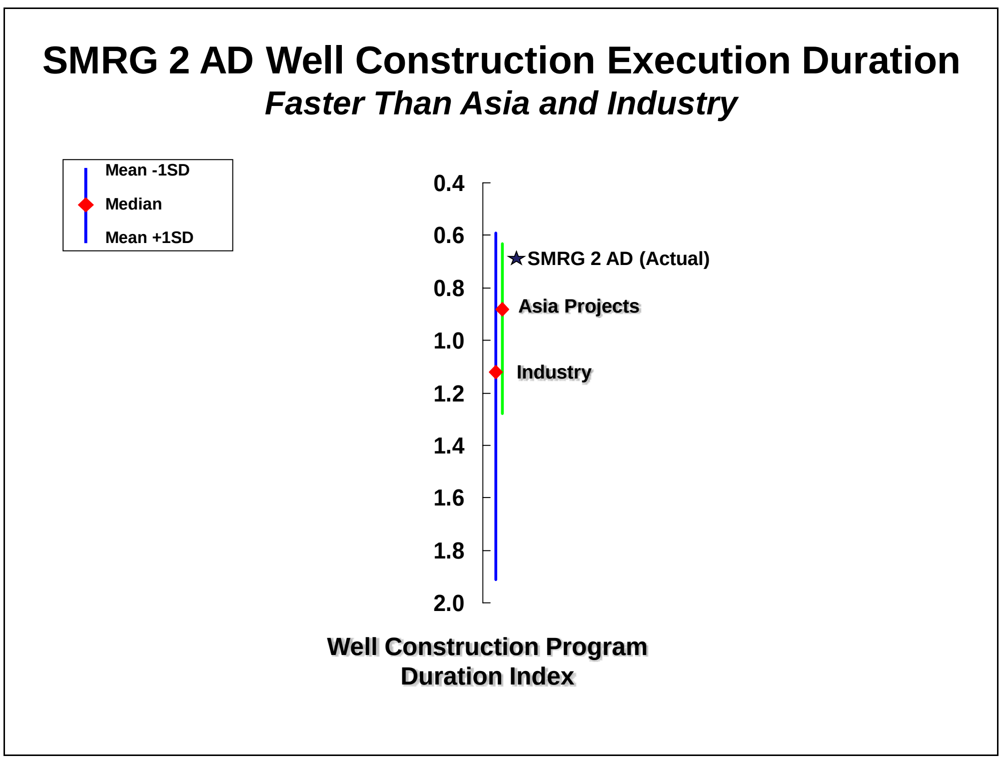

Figure 3

Figure 2 shows that the SMRG 2 AD team executed wells program much faster than Industry. Actual wells execution duration for the SMRG 2 AD Project was 94 days, which is

32 percent shorter than industry average of 139 days. It should be noted that (1) industry average was adjusted to include 10 days of plug & abandon (P&A) and slot recovery; and (2) days for mobilization, demobilization and waiting on weather were added to wells durations (17 days for estimate and 11.5 days for actual).

Based on well programs recorded in IPA database, Asia projects on average execute wells programs faster than projects outside Asia. However, further analysis shows that the SMRG 2 AD wells program is also faster than the Asia average (Figure 3).

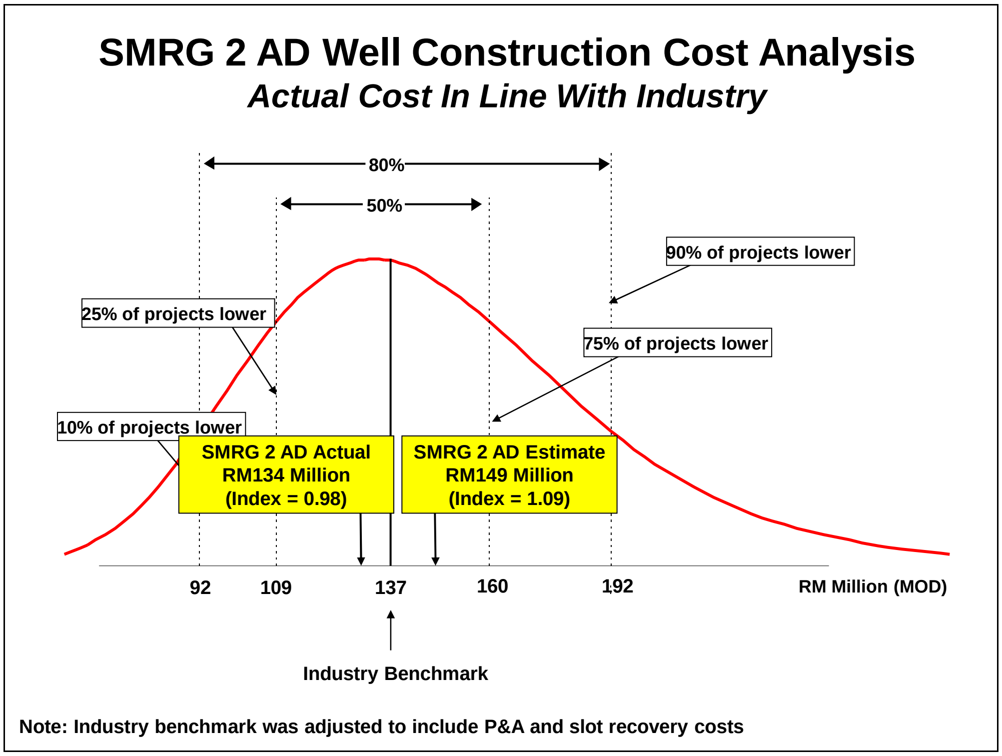

Figure 4

Figure 4 shows that SMRG 2 AD wells were executed with cost in line with industry average, after adjusted for P&A and slot recovery costs (RM8.0 million for estimate and RM8.6 million for actual). Actual wells execution cost for the SMRG 2 AD Project was RM134 million, which is 2 percent lower than industry average of RM137 million.

Given such a fast execution duration (32 percent shorter) as shown in Figure 2, the wells execution cost would be expected to be much lower than industry average (because duration is the main measure of cost). This indicates a significant disconnect between the wells execution duration and cost. To understand possible contributing factors to this disconnect, further analysis was conducted in the next section.

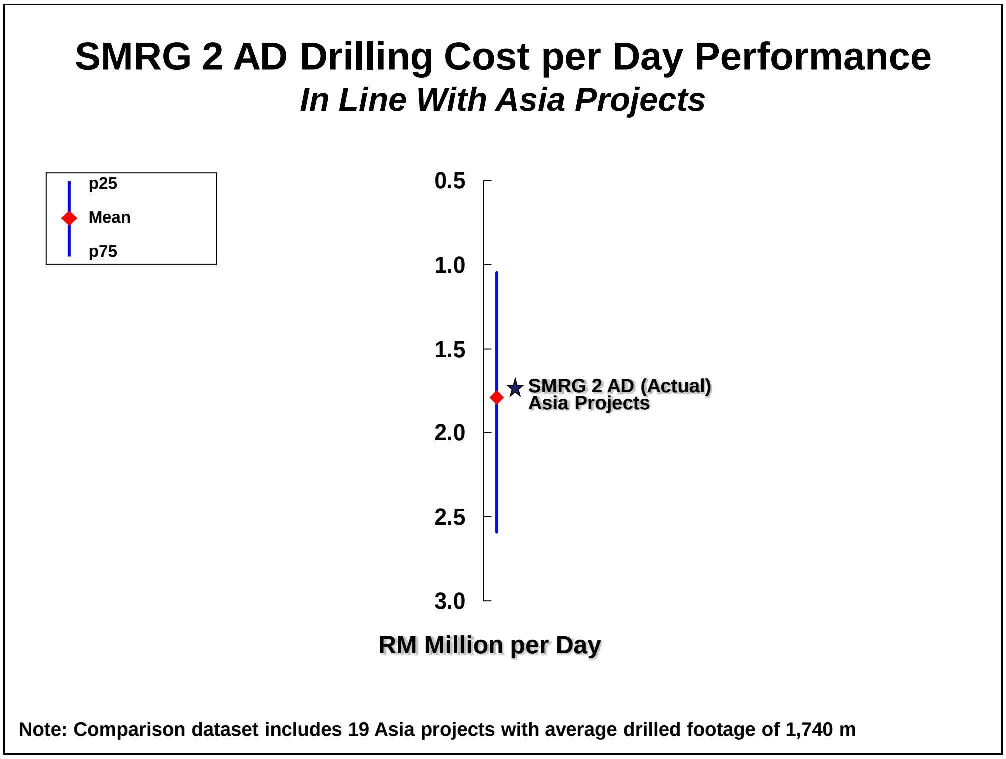

Figure 5

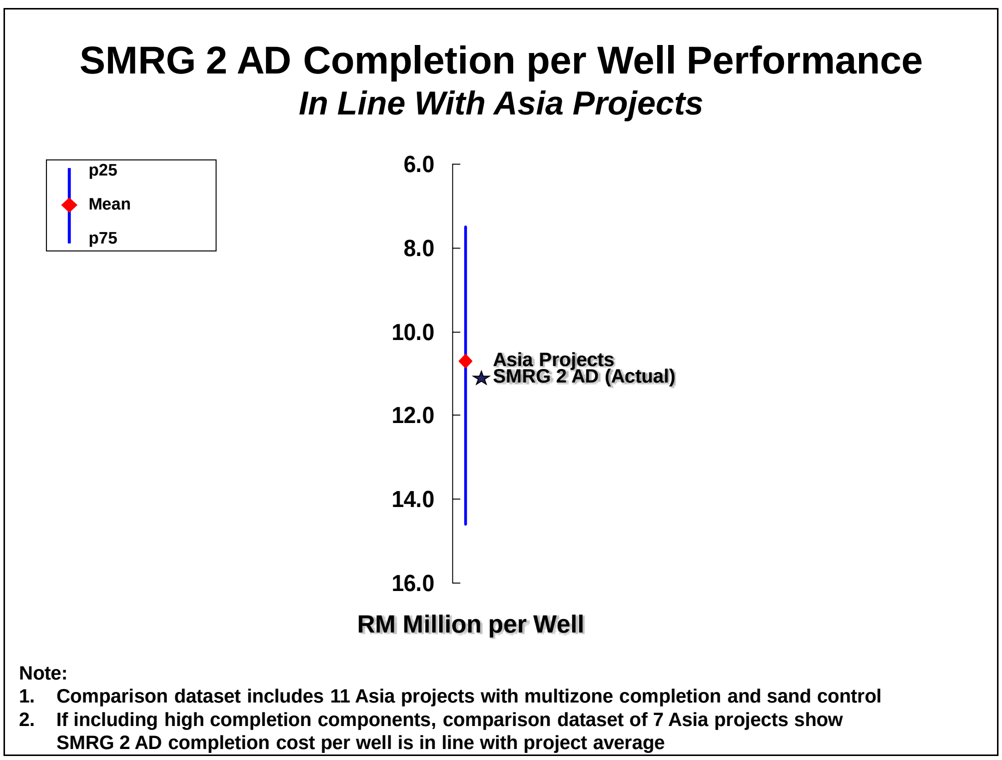

Figure 6

To understand the disconnection between SMRG 2 AD wells execution duration and cost, we carried out further analysis of the drilling and completion cost using comparative dataset. The results are shown in Figure 5 and Figure 6.

Figure 5 shows that the drilling cost per day for SMRG 2 AD is in line with Asia projects in the comparative dataset (for drilled footage average of 1,740 m). However, the SMRG 2 AD was executed with a rig cost of US$143,700 per day which is higher than average rig rate of US$120,770 per day[9]. So if adjusted for the difference in rig rate, the drilling cost per day for SMRG 2 AD would be less than industry average.

Figure 6 shows that the completion cost per well for SMRG 2 AD is in line with Asia average for wells with high completion components, multizone completion and sand control. However, the SMRG 2 AD used 13Cr in completion items such as production tubing, sand control screen, and swellable packers. However, the detail available for the comparison projects completions scopes is insufficient to control for these aspects. If adjusted for these factors, the completion cost per well for SMRG 2 AD would be less than industry average.

In addition to drilling and completion cost, further analysis showed that SMRG 2 AD Project wells office cost is higher than industry average. Based on well programs recorded in IPA database projects[10], on average, executed wells programs with office cost 27 percent less than the SMRG 2 AD Project's.

Facilities Execution Duration Outcomes

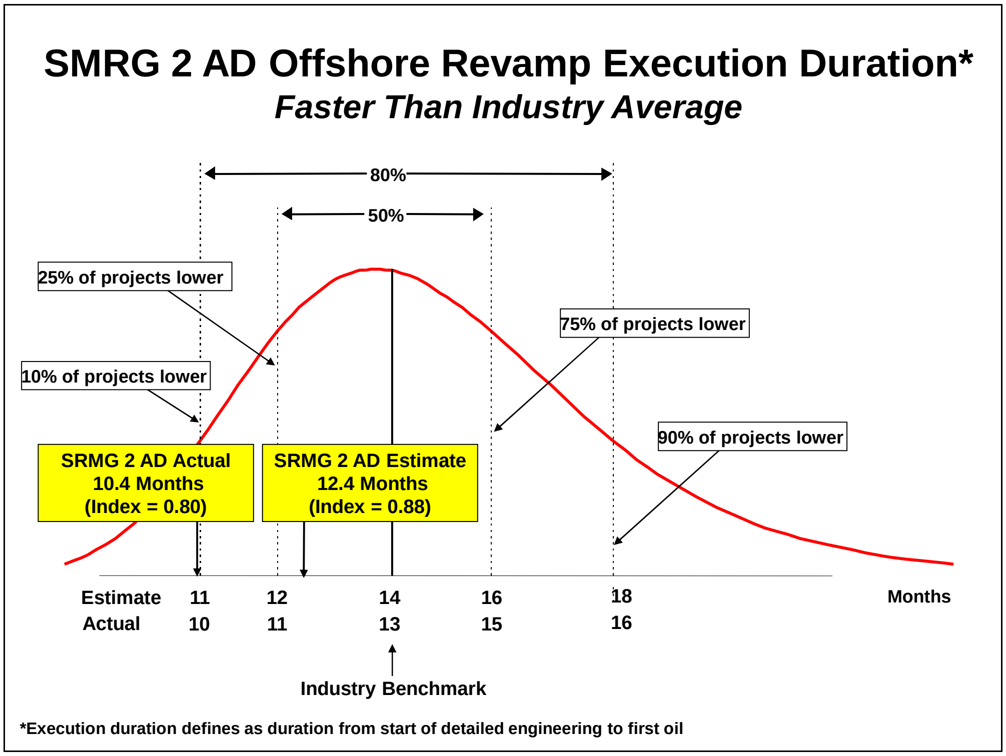

Figure 7

For the SMRG 2 AD Project, both estimate and actual execution durations are faster than industry average (Figure 7). The actual execution duration is 20 percent faster than Industry and falls outside the normal range.

[9] Rate is average rate for jack-up rig in Southeast Asia in June 2012.
[10] The dataset comprises 23 closeout projects authorized in 2009 or later.

Cost Predictability

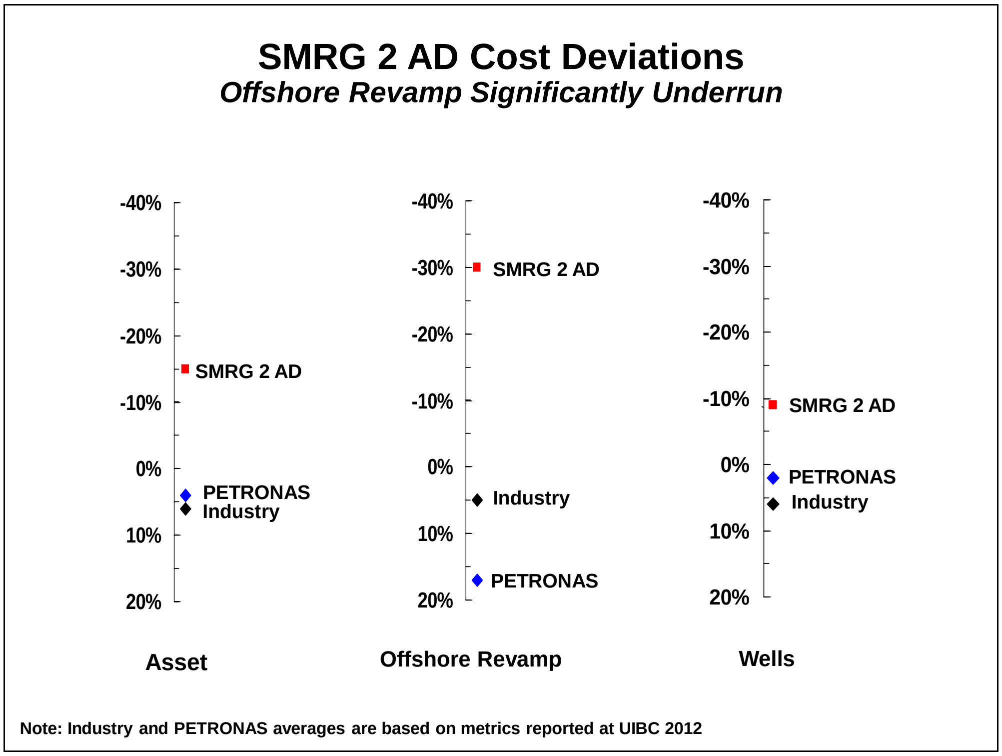

Figure 8

Figure 8 shows the cost deviation of the SMRG 2 AD Project for offshore revamp, wells and total asset development. These deviations were adjusted for escalation and currency difference. The SMRG 2 AD Project was executed with a 15 percent cost underrun. Wells and especially offshore revamp cost reduction both contributed to the cost underrun. In overall, the cost deviations were caused by different rig and vessels used for estimate and actual and by savings from execution optimization. There was no major design change that caused deviation in cost.

The offshore revamp's actual cost is 30 percent less than estimated. Main factors contributing to lower actual cost than estimate are:

1. *Project management cost*. Team completed project earlier than planned.

2. *Material costs*. During execution, SIPROD panels, deluge valves and wellhead control panel were either borrowing from Sabah operations team or re-using existing items. This eliminated the need to buy new items and hence reduce material costs.

3. *Marine spread*. At the time of sanction, support vessel was not confirmed. The team estimated marine spread based on workboat with capacity 70/80 pax at a rate of RM95,000 per day. During execution, because team utilized the anchor handling tug supply (AHTS) vessel and rig facilities to optimize cost, a smaller support vessel was required. Team managed to get the supply boat with capacity 40 beds at a rate of RM55,000 per day.

4. *SIPROD requirement*. Savings were realized because SIPROD was not required for SMJT-G during execution[11].

5. *Junk clearance*. Junk clearance was planned with two separate mobilizations but executed with one.

The wells execution cost is 9 percent less than planned. Main factors contributing to lower actual cost than estimate are:

1. *Project management cost*. Team completed project earlier than planned.

2. *Drilling cost*. Drilling cost deviation were contributed by high supply vessels rates than estimate but this was compensated by lower rig rate and tangible materials. Actual rate for supply vessels were nearly double than estimate because the supply vessels planned to use was not available at execution (support vessels are managed centrally and vessel assignment is outside team control). No rig was confirmed or contracted at sanction. The team used rig *Naga-3* rate of US$165,000 per day for estimate. However, rig *Maersk Convincer* was used with US$143,700 per day. In addition, drilling tangible cost was lower because less materials were required during execution.

Schedule Predictability

The facilities execution duration was 16 percent faster than planned because it was planned that two wells from the SMJT-F platform (SM-82ST2 and SM-84ST1) would be batch drilled and completed first to achieve first oil. However, not having SIPROD on SMJT-G allowed SM-101 to be executed first to achieve earlier first oil.

Resource Promise Estimate Outcomes

Table 6
SRMG 2 AD Project Resource Promise Estimate (RPE) Metrics Summary

Outcome Metric	SMRG 2 AD Project		Industry Average	PETRONAS Average
	Estimated	Actual		
RPE by 2020 (MMbbl)	2.17	2.51		
Change in RPE between sanction and first production (at 2020)		16%	–7.5%	–6.8%
Probability of a P50 RPE downgrade greater than 20 percent (significant downgrade)	22%	22%	27%	20%
Probability of the Post Startup P50 falling outside of the RPE range[12]	7%	7%	Not Available	Not Available
Production Attainment in Months 7-12	100%	Not Available	74.0%	50.5%

The SMRG 2 AD Project's RPE increased by 16 percent over what was planned. The estimated RPE was 2.17 MMbbl and the actual RPE is 2.51 MMbbl. Table 7 summarizes the reserve changes for each well and shows that the RPE increment was mainly the result of changes in SM-101 and SM-82ST2. For SM-101, recovery from K sand was 22 percent lower than expected. Open-hole logs in the SMRG 1 Project drilling showed some compartmentalization in K sand but this information was not updated in the estimate. For SM-82ST2, the RPE increase was the result of additional sands identified during drilling

[11] Decision was made based on economic analysis conducted in July 2012.
[12] IPA defines the RPE range as (high RPE case – low RPE case)/expected RPE.

through open-hole logs. For surface facilities, there is no issue in handling additional production volume. In addition, shallow reservoir fluid properties are very similar and sand production is below PCSB requirements.

Table 7
SRMG 2 AD Project RPE by Wells Summary

Wells	2020		
	Planned	Actual	Percentage
SM-101	0.77	0.6	-22%
SM-82ST2	0.74	1.2	62%
SM-84ST1	0.66	0.71	8%
TOTAL	**2.17**	**2.51**	**16%**

Based on the *Moderate* appraisal strategy, the SMRG 2 AD Project has a 22 percent probability of a P50 reserve estimate downgrade by greater than 20 percent. The team recognized the remaining uncertainties and risks in the appraisal and mitigated them by setting a very broad RPE range of 94 percent at sanction[13]. This results in a low (7 percent[14]) likelihood of the RPE falling outside the RPE range.

At the time of the project interview, the production data for month 7 to 12 after first oil was not yet available. Data for the first 5 months after first oil are very provisional numbers based on well test results, rather than official back allocated production. It should be highlighted that production allocation from the Samarang field was revised in December 2012. The initial allocation of production for the Samarang field was by difference using oil meters from Sumandak, Kinabalu, and LCOT. New oil meters have been installed for the Samarang export line and the production rates show a large discrepancy between the figures obtained by difference from previous years. The recovery factor allocated to Samarang was initially 0.59 but since the meters were installed, the actual oil recovery factor works out to be 0.80. This will result in the need to review production profiles going forward for the Samarang field. We will follow up with a second closeout on the full production attainment assessment when final production data for month 7 to 12 are available.

PROJECT DRIVERS

Table 8 summarizes practices and drivers at sanction for the SMRG 2 AD Project assessed during this closeout evaluation (July 2013). Drivers and practices at sanction for the SMRG 2 Project assessed during the prospective evaluation (December 2011) are also shown because most of practices and drivers for the SMRG 2 Project are also applicable to the SMRG 2 AD Project. For detailed descriptions of the reasons for ratings of drivers that are unchanged, please refer to the December 2011 prospective report. We describe in detail below only drivers whose ratings changed because they are applicable specifically to the SMRG 2 AD Project. Industry and PETRONAS averages at sanction reported at the November 2012 annual meeting of the Upstream Industry Benchmarking Consortium[15] (UIBC 2012) are also included for reference.

[13] At closeout, the RPE range was revised to 98 percent.
[14] This is within IPA's recommended range of 0 to 20 percent.
[15] 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.

Table 8
Summary of the SMRG 2 AD Project's Practices and Drivers

Driver or Practice	SMRG 2 (Prospective – Nov 2011)	SMRG 2 AD Closeout – Jul 2013)	Industry Average at Sanction	PETRONAS Average at Sanction	Best Practice
Appraisal Strategy	*Moderate*	*Moderate*	*Conservative:* 38% *Moderate:* 37% *Aggressive:* 25%	*Conservative: 50% Moderate: 38% Aggressive: 13%*	Not Applicable
Reservoir Complexity Index	49	53	39	38	Not Applicable
Wells Complexity Index	47	51	56	49	Not Applicable
FEL Index – Asset	6.97 (*Poor*)	5.77 (*Fair*)	6.29 (*Fair*)	6.39 (*Fair*)	4.00 to 5.50
- Reservoir	5.49 (*Good*)	5.49 (*Good*)	5.90 (*Fair*)	5.93 (*Fair*)	4.50 to 5.50
- Wells	6.36	6.36[16]	5.98	6.13	5.00 to 6.00
- Facilities	8.75 (*Poor*)	5.75 (*Good*)	6.79 (*Fair*)	7.04 (*Fair*)	4.00 to 4.75
Team Development Index (TDI)	*4.00 (Good)*	*4.00 (Good)*	2.87 (*Fair*)	2.89 (*Fair*)	*Good*
Team Integration	Yes	Yes	54% of Projects Integrated	56% of Projects Integrated	Yes
Operations Integration of With Project Team	Yes	Yes	80% of Projects Integrated	89% of Projects Integrated	Yes
Facilities Technical Innovation	*Conventional*	*Conventional*	*Conventional:* 71% *Moderate:* 25% *Substantial:* 4%	*Conventional: 86% Moderate: 14% Substantial: 0%*	Not Applicable
Wells Technical Innovation	*Conventional*	*Conventional*	*Conventional:* 62% *Moderate:* 35% *Substantial:* 3%	*Conventional: 63% Moderate: 38% Substantial: 0%*	Not Applicable

For the SMRG 2 AD Project, the targeted reservoirs comprise shallow sands. There is no change in reservoir complexity for these sands compared to what was assessed for the SMRG 2 Project in which the Reservoir Complexity Index (RCI) for sands E, F, G, H, and I is 58 and for sand K is 44. However, the overall average reservoir rating for the SMRG 2AD Project is different from that of the SMRG 2 Project because the SMRG 2 Project also includes MN and OPQ sands. Based on weighted reserves, the average reservoir complexity rating for SMRG 2 AD reservoir is 53, which is more complex than the industry average of 39 and outside the standard deviation range of 31 to 47. The complexities are mainly attributed to a high degree of compartmentalization, high fault density, high reservoir stacking, and weak reservoir energy drive. The *Moderate* appraisal strategy highlights the remaining risks and uncertainty in estimated recoverable volumes given the seismic quality, reservoir complexity, and data quality.

The SMRG 2 AD Project wells have a Well Complexity Index (WCI) of 51, which is lower than industry average of 56 but within the standard deviation range of 36 to 74. For the SMRG 2 AD Project, there is no change in well complexity from what was assessed for the SMRG 2 Project. However, the overall WCI for the SMRG 2 AD Project wells is different from those in the SMRG 2 Project because wells for the EOR program are not included in the assessment. The well complexity is affected by the multizone completion, high completion components, and sand control.

[16] Re-calculation of Wells FEL resulted in the same Wells FEL rating as the Prospective evaluation in November 2011.

In terms of technology, shallow water slot recovery and open-hole completions with standalone screens and swell packers are conventional to Industry but new to Samarang.

Reservoir Front-End Loading (FEL) was *Good,* which is better than both the industry and PETRONAS averages of *Fair.* Wells FEL trails both industry and PETRONAS averages at sanction. The major gaps were (1) the lack of confirmation of rig availability and (2) procurement of LLIs for completion issued without an approved contract in place. Team identified these risks and plans were put in place to mitigate. The Facilities FEL was *Good,* which is better than the industry and PETRONAS averages. This rating is better than the rating given during the prospective evaluation (*Poor*) because the Facilities FEL at the prospective evaluation was a result of the *Poor* rating for the greenfield scope (EOR program). For the SMRG 2 AD Project, the lack of support vessel confirmed at sanction and a resource and cost loaded schedule were the main factors preventing the Facilities FEL from achieving a *Best Practical* rating.

The SMRG 2 AD Project had a *Good* Team Development Index (TDI), and the asset team was *Integrated* as assessed in the prospective evaluation for the SMRG 2 Project. Project objectives were defined and understood by team members. All functions that could influence project outcomes were present on the team. Team roles and responsibilities were defined and understood. Risk registers were used for various functions. The SMRG 2 AD Project was approved by PMU to combine a series of reviews in one session as an exception from the standard PPMS.

PROJECT EXECUTION DISCIPLINE

Table 9
Summary of the SMRG 2 AD's Execution Discipline

Project Execution Discipline	SMRG 2 AD Project	Industry Average	PETRONAS Average	Best Practice
Project Control Index (PCI)	*Good* (planned) *Good* (actual)	*Fair* (planned) *Fair* (actual)	*Fair* (planned) *Poor* (actual)	*Good*
Major Late Changes	No	57% of projects	33% of projects	No
Project Manager Turnover	No	25% of projects	33% of projects	No

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.

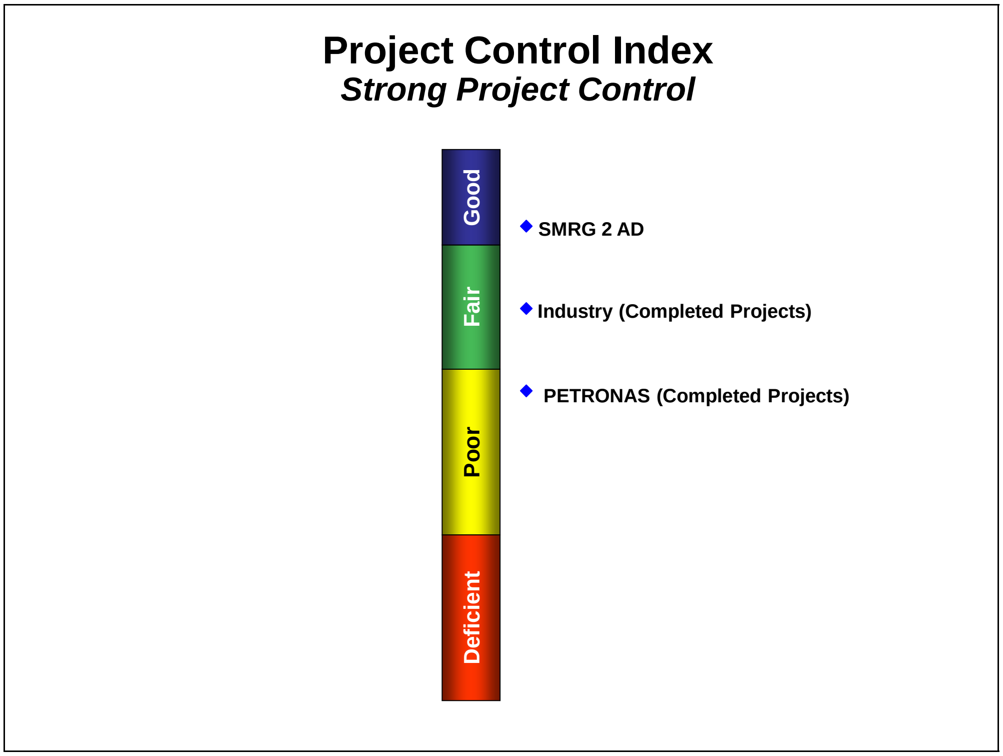

Figure 9

As shown in Figure 9, the SMRG 2 AD Project had a planned Project Control Index (PCI) in the *Good* range, better than Industry and PETRONAS average. This plan was followed through during execution. The team actively managed the HUC contractor in both onshore and offshore activities. Team representatives were at the contractor yard and on platforms to track and monitor progress, qualities, and safety. Progress was reported monthly at discipline levels. A cost control and a planner were assigned during project execution. In addition to a detailed planned project control, "Control Room" application was established in 2011 to assist the process of monitoring and tracking project progress and performance so that risks could be prevented and mitigated at timely manner. The "Control Room" includes risk register, lessons learnt, contract details, budget, schedule, technology and its associated risks (for both proposed and implemented technology). This "Control Room" application enables all stakeholders and team members aligned on project risks, project status and performance. Furthermore, when risks are registered centrally, risks are better prioritized, critical risks are better assigned to track and action.

Major Late Changes

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

IPA measures as a major late change any design and/or scope change that takes place after FID that costs or saves the equivalent of 0.5 percent of the sanction estimate or causes at least 1 month of schedule delay or acceleration. We exclude the changes to the project's execution strategy and changes driven by external factors such as weather or strikes from our major late changes definition. Moreover, IPA does not consider either cost trending or rework, which are often captured in project change logs, as project changes. Based on these criteria, the SMRG 2 AD Project had no major late change.

Team Turnover

The SMRG 2 AD Project did not have any project manager turnover. However, there were several turnovers in different disciplines such as the subsurface team (October 2012), drilling manager (June/July 2012), and cost control engineer (March 2012). These turnovers were the result of company policy, such as staff rotation, and thus were external to the project. In addition, the turnovers did not have an adverse effect on project performance. However, it should be noted that turnover in lead positions other than the project manager can affect project performance. IPA research shows that turnover in wells lead positions can erode drilling cost and schedule performance (Figure 10).

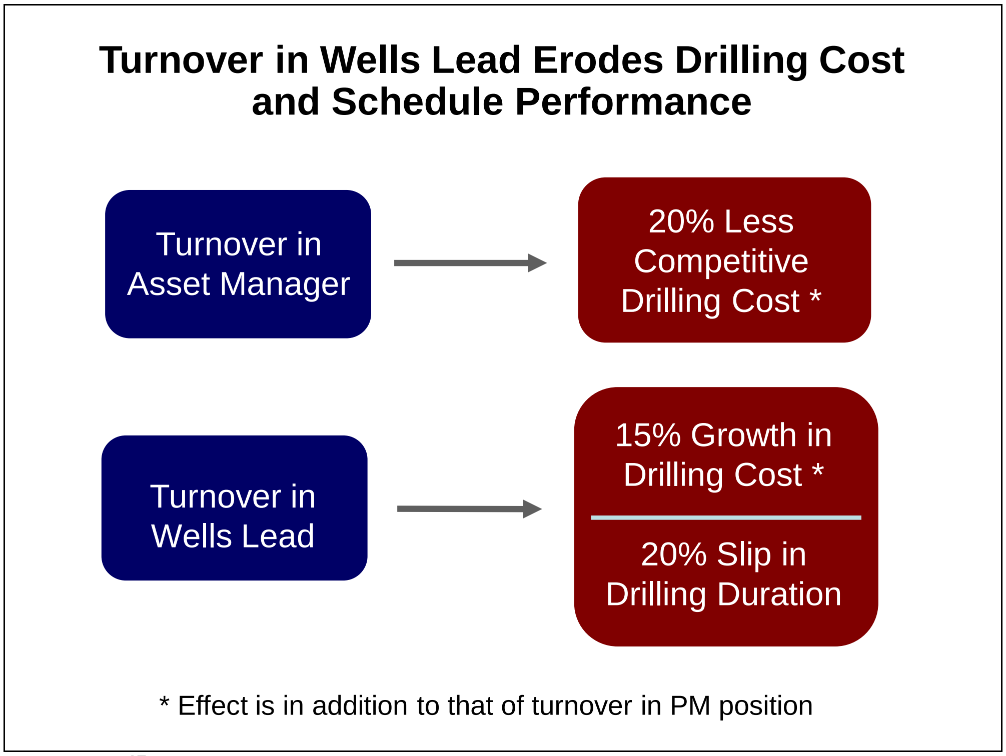

Figure 10[17]

[17] Margit Jochman, Gauri Kayande, and Kate Rohrbaugh, *The Effect of Lead Member Turnover*, UIBC 2009, IPA, November 2009.

LESSONS LEARNED

Based on our analysis of historical industry performance and our assessment of the SMRG 2 AD Project, we present the following key lessons for future projects executed by PETRONAS. It should be note that lessons learnt for the project conducted by the project team were not captured in this report.

POSITIVE LESSON LEARNED

1. **A solid foundation and disciplined execution drive good outcomes**. The SMRG 2 AD Project demonstrated that success flows from early stakeholder alignment, good project definition at sanction, an integrated team, execution with detailed planning and discipline, and strong project controls such as actively managing contractors with a hands-on approach and closely tracking progress.

RECOMMENDATIONS FOR FUTURE PETRONAS PROJECTS

2. **Track all lessons learned, particularly those related to deviating from the project process**. The SMRG 2 AD Project presents an opportunity to pass on learnings for the benefit of future projects. However, its success was based on some unique circumstances that might not be duplicated. Therefore, this project needs to carefully document the reasons why changes to the system were made and highlight the benefits obtained and some risks taken, with emphasis pertaining to why these were specific to this project.

3. **Maintain team continuity; minimize the turnover of not only the project manager but also other key positions such as in reservoir and wells.** The SMRG 2 AD Project had no project manager turnover but several turnovers in other key positions in subsurface team and wells. Although these turnovers were outside the team's control and there was no adverse impact on project performance, IPA research found that turnover in reservoir or wells lead can erode drilling cost and schedule performance.

COST AND SCHEDULE APPENDIX

PROJECT COST DISTRIBUTION

Table 10 summarizes the estimated and actual costs for the SMRG 2 AD Project using the project team's cost breakdown.

Table 10
Cost Distribution for the SMRG 2 AD Project (MOD RM Million)

Cost Category	Estimate (May 2012)		Actual (July 2013)	
	Revamp	D&C	Revamp	D&C
Detailed Engineering	2.40		1.89	
Project Management	12.50	20.20	8.30	10.43
Fabrication	3.15		2.75	
Non Wells Activities		16.41		17.21
Tree		3.75		3.30
Drilling		69.41		65.56
Formation Evaluation		3.88		2.18
Completion		35.23		34.93
T&I	14.24		10.04	
HUC	11.34		5.82	
Others	14.32	0.09	11.62	0.13
TOTAL	57.95	148.97	40.42	133.74
GRAND TOTAL	**206.92**		**174.16**	

PROJECT SCHEDULE

Table 11 summarizes the schedule of the SMRG 2 AD Project. The planned execution schedule was 12 months. The actual execution time was 10 months. First production was planned for 26 February 2013, and was achieved on 22 December 2012.

Table 11
Schedule for the SMRG 2 AD Project

Project Phase	Planned			Actual		
	Start	Finish	Duration (Months)	Start	Finish	Duration (Months)
FEED	1-Apr-10	6-Oct-11	18	1-Apr-10	11-Apr-12	24
Overall Contracting Strategy	30-Jan-12	30-Mar-12	2	30-Jan-12	30-Aug-12	7
Gate #03 Approval	4-Jun-12			19-Jun-12		
Detail Engineering	15-Feb-12	13-Jun-12	4	15-Feb-12	11-Oct-12	8
Procurement (Bid/Evaluate/Award/Delivery)						
Facilities LLIs	29-Feb-12	22-Dec-12	10	1-Mar-12	30-Oct-12	8
HUC	19-Apr-12	1-Dec-12	7	10-Aug-12	14-Nov-12	3
Drilling	9-Jan-12	26-Nov-12	11	9-Jan-12	26-Dec-12	12
Completion	9-Jan-12	1-Oct-12	9	9-Jan-12	11-Jan-13	12
Fabrication/Construction						
Onshore Fabrication	23-Aug-12	1-Oct-12	1	10-Oct-12	2-Nov-12	1
Junk Clearance	24-May-12	14-Jun-12	1	15-Sep-12	22-Oct-12	1
Offshore Construction	26-Sep-12	17-Nov-12	1.7	1-Nov-12	17-Dec-12	2
Well Operation						
Rig Mobilization	24-Nov-12	29-Nov-12	0.2	15-Nov-12	22-Nov-12	0.2
F-14 & F15	29-Nov-12	2-Mar-13	3	19-Nov-12	15-Feb-13	3
G-03	2-Mar-13	28-Mar-13	1	21-Nov-12	15-Dec-12	1
Rig Demobilization	28-Mar-13	1-Apr-13	0.1	15-Feb-13	18-Feb-13	0.1
Hookup and Commissioning	14-Feb-13	5-Apr-13	2	24-Dec-12	20-Mar-13	3
First Oil	**26-Feb-13**			**22-Dec-12**		
Execution Duration (Detailed Engineering to First Oil)	**15-Feb-12**	**26-Feb-13**	**12**	**15-Feb-12**	**22-Dec-12**	**10**