INDEPENDENT PROJECT ANALYSIS

excellence through measurement

A Closeout Evaluation of the Dulang Phase 1 Redevelopment Project

Delivered to PETRONAS

April 2014

REVISED FINAL

Confidentiality Statement

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Project File: PET-2304-CLO

Preface (1)

- **IPA evaluated PETRONAS's Dulang Phase 1 Redevelopment Project in 2011* at end of Front-End Loading 3 (FEL 3) or MR5****

- **This closeout (CLO) evaluation assesses the Dulang Phase 1 Project after start-up**
  - **Phase 2 not assessed as part of this evaluation**

- **Project interviews held with Dulang Phase 1 Project team in Kuala Lumpur on 12 and 13 September 2013**

*** Erik Kowa, Khanh Nguyen, and Trung Ghi, *A Prospective Evaluation of the Phase 1 Dulang Redevelopment Project*, IPA, September 2011**

****Milestone Review**

Preface (2)

- **PETRONAS provided project documentation and data for IPA evaluation**
  - **Findings based on team member interviews and project documentation at MR5 and at completion**
- **Although project team members provided information, interpretation and analysis are IPA's and do not necessarily reflect views of those interviewed**

Objectives of This Closeout Evaluation

To: Compare performance of the Dulang Phase 1 Redevelopment Project with performance planned at project final investment decision (authorisation) in July 2011

By: Comparing project with other completed projects in Industry

Establishing benchmarks for project's schedule and cost performance

Sharing research on drivers of success and failure in exploration and production developments

So: Lessons learned can be used to improve future performance of PETRONAS projects

Scope to be Benchmarked

- **This evaluation includes benchmarking of the following scope:**
  - Reservoir complexity
  - Appraisal strategy
  - Reservoir Front End Loading
    - Inputs, Constraints, Tasks, Reservoir Execution Planning
  - Wells technology selection and complexity
  - Team development index
  - Wells Front End Loading
    - Scope of Work, Regulatory/HSE, Well Engineering, Execution Planning
  - Wells cost and schedule targets and outcomes
  - Reservoir volatility

Outline

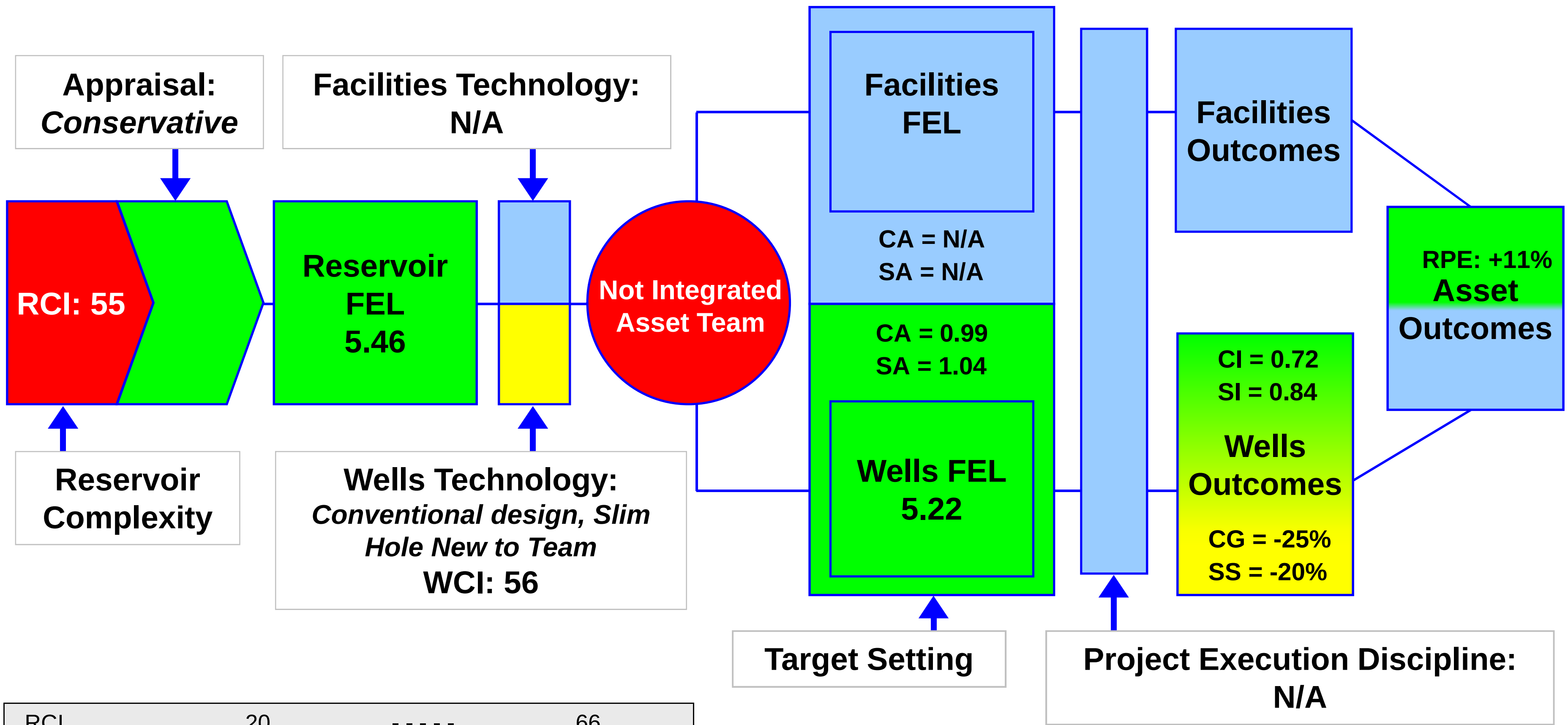
- ***Key Message and Pathway Summary***
- **Project Background**
- **IPA Process and Methodology**
- **Basis of Comparison**
- **Practices and Drivers**
- **Outcomes**
- **Conclusions and Lessons Learned**

Key Message

- **Dulang Phase 1 Redevelopment Project achieved its cost, schedule, and production targets**
  - **Although system constraints mean sales production is yet to be achieved**
    - **Requires further studies and debottlenecking**
- **Solid planning and in-depth subsurface studies led to competitive wells outcomes with little change to resource promise estimate**
  - **EOR production performance has been used as a decision tool for Phase 2, and will be further understood over time**
  - **Wells cost predictability was however poor with efficiencies driving lower cost**
- **PETRONAS should take the positive points of Dulang Phase 1 and share within their organisation**

Summary of the Dulang Project Phase 1

Solid Plans Led to Competitive Results



RCI	20	- - - - -	66
WCI	25	- - - - -	123
Risk	<<< Less	- - - - -	More >>>
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	Low	Medium	High

RCI = Reservoir Complexity Index
WCI = Wells Complexity Index
FEL = Front-End Loading

CA = Cost Aggressiveness
SA = Schedule Aggressiveness
CG = Cost Growth
RPE = Resource Promise Estimate
PA = Production Attainment
SS = Schedule Slip

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- Key Message and Pathway Summary
- ***Project Background, Scope, and History***
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Business and Project Objectives (1)

- **Overall project objective was to address declining Dulang Field production through enhanced oil recovery (EOR)**

- **Phase 1 aimed to develop 25.0 MMSTB* of oil reserves to accelerate overall Dulang Redevelopment Project**
  - **Targeted cost of RM1,065.4 million**
  - **No discussion of operability, safety, schedule, expandability, cost, life expectancy, maintainability for Phase 1**
  - **No discussion of data requirements for Phase 2 development**

- **Project objectives articulated at a high level however trade-offs not clearly communicated at a project level**
  - **What is the value of 1 month first oil delay?**

*** Million standard barrels**

Business and Project Objectives (2)

- **Production performance resulting from WAG* development is difficult to measure**
  - **Common problem in industry**
  - **Competing production enhancement projects make it difficult to measure sales production from Phase 1 Dulang Redevelopment Project**
  - **Project value will be further understood over time as more production data is acquired**
    - **Reservoir management plan in place to measure production over time**

*** Water alternating gas**

Project Background
Field Summary

- Dulang field is in South China Sea, 176 km off coast of Kerteh, peninsular Malaysia in block PM6; field covers about 27 km by 5 km
  - Shallow water (~76 m), average vertical depth ~5,300 ft
- Discovered in 1981 by ExxonMobil, developed by PCSB* and ExxonMobil since early 1990s
- Existing Dulang complex comprises 4 platforms (3 wellhead platforms and 1 processing platform)
- Field is complex structurally with dense faulting
- Production sharing contract will end in 2021

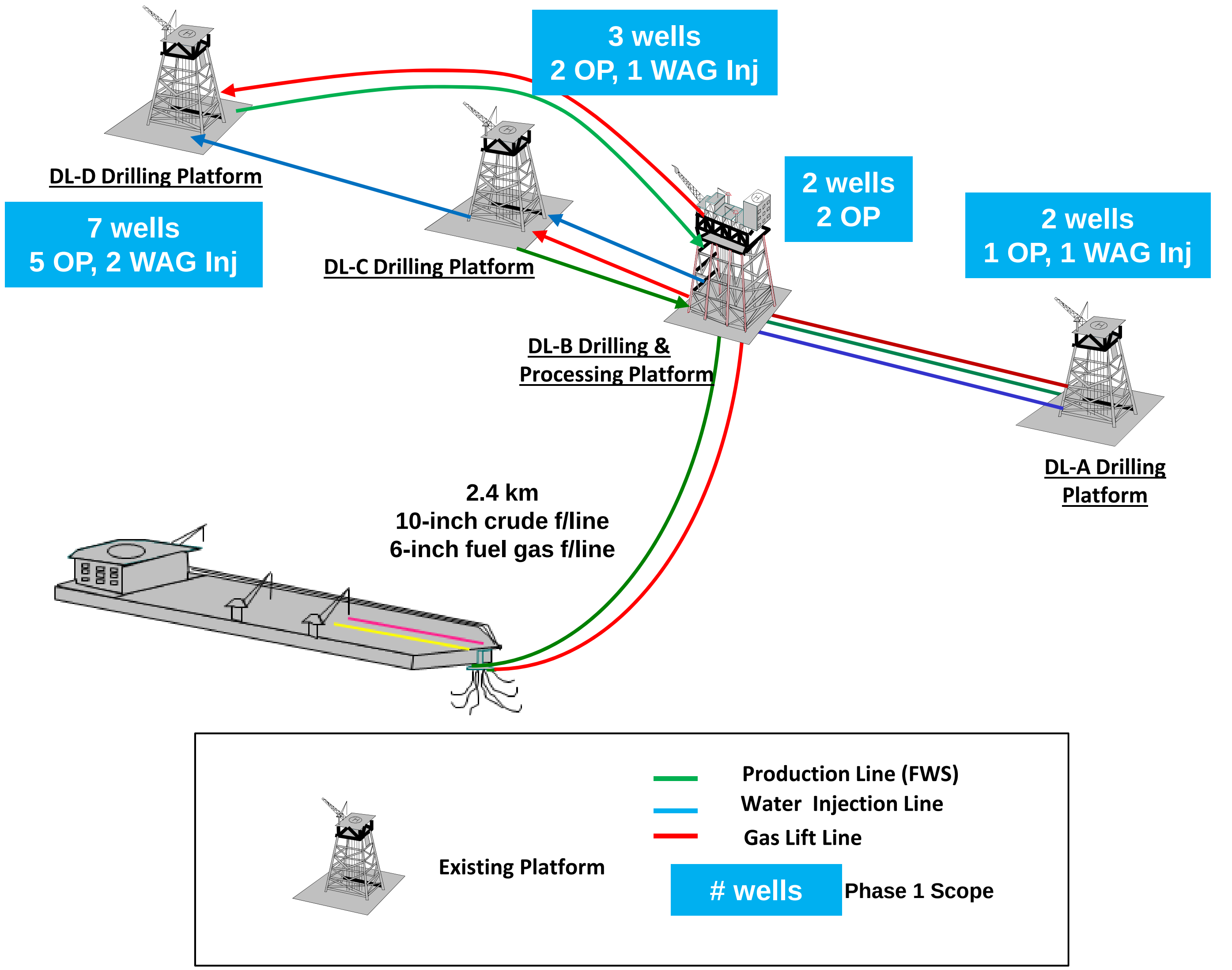
* PCSB – PETRONAS Carigali Sdn Bhd

Project Background
Drilling History

- 148 development wells drilled from 1990 to 2011 on DL-A, DL-B, DL-C, and DL-D platforms
- 1 revisit to field in 2001-2002
  - 6 sidetrack wells on DL-A
  - 2 sidetrack wells on DL-B

Project Background

Phase 1 Dulang Redevelopment Project Scope (1)



Source: Dulang Redevelopment Project Phase 1 – IPA Closeout Report Briefing

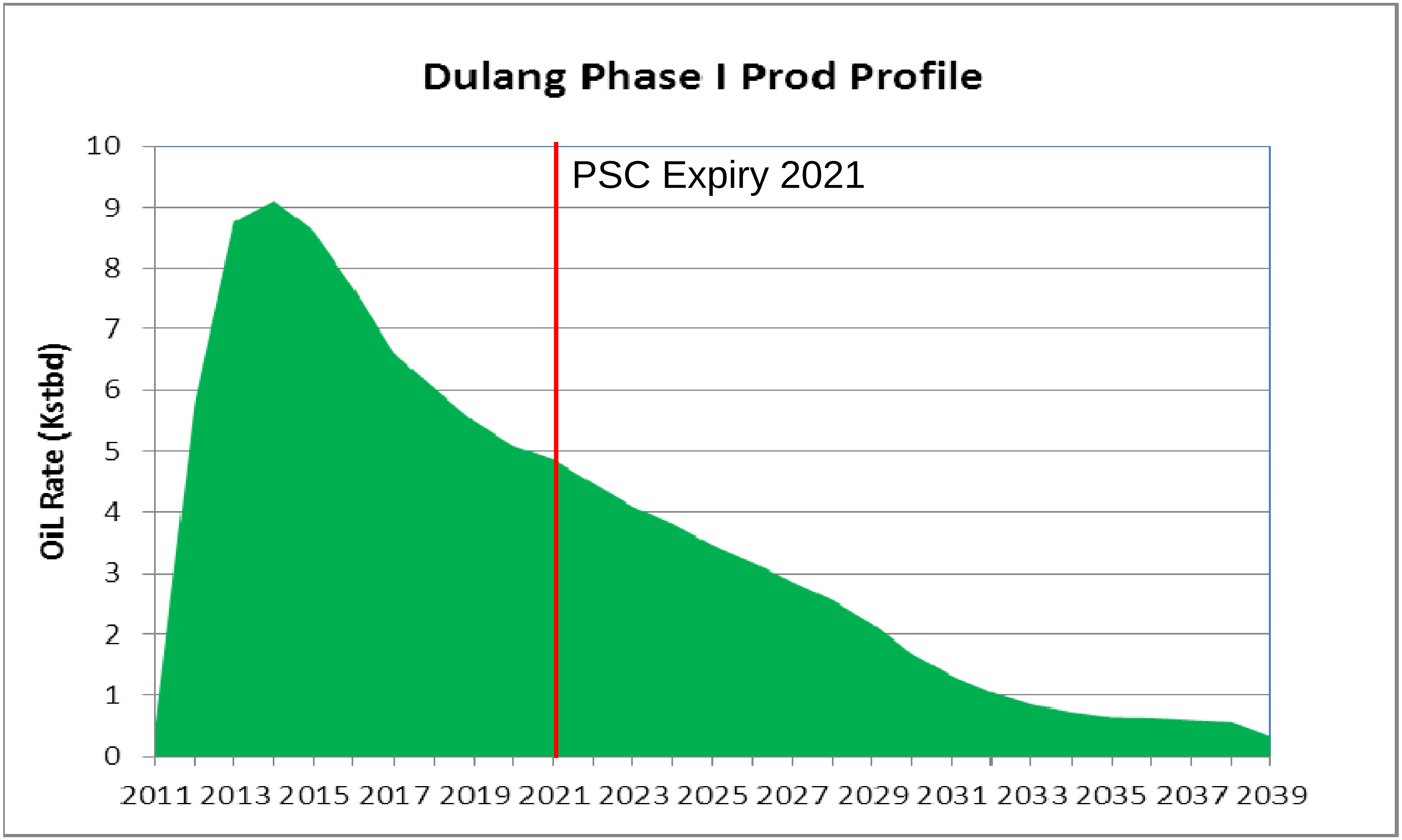
Project Background

Phase 1 Dulang Redevelopment Project Scope (2)

- Flowline tie-in and header modifications (SIPROD*)
- Platform structural modifications and strengthening to accommodate tender assist drilling rig
- 8 infill wells from 9 available platform slots
  - 2 at DL-C
  - 6 at DL-D
- 6 sidetrack wells from existing platforms
  - 2 at DL-A
  - 2 at DL-B
  - 1 at DL-C
  - 1 at DL-D
- One additional oil production well drilled (total 15 wells)
  - Well was approved and added to project after authorisation

* Simultaneous production

Phase 1 Dulang Production Profile
9.1 kb/d Peak Production to Deliver 25.0 MMstb to End PSC



Source: Dulang Redevelopment Project Phase 1 – AIP Closeout Report Briefing

Project Background
Execution and Contracting Strategy

- **Overall Dulang Redevelopment planned in two phases**
  - **Phase 1 included infield drilling and forms the basis for this evaluation**
  - **Phase 2 planned for sanction in 2012 but has been delayed**
- **Phase 1 used standard PCC contract and existing PCSB umbrella contracts for drilling, HUC, and support services**

Key Project Milestones (1)

- August 2004 – Work began on a Full Field Review (FFR) to assess the reservoir management strategy of major Dulang reservoirs
  - Detailed, integrated field development plan generated
- July 2007 – FFR partially complete and audit of work began along with WAG EOR studies
  - Studies involved a WAG EOR offshore pilot trial
- July 2008 – Petrotel consultants initiated concept select for Dulang Redevelopment Project
- September 2009 – PETRONAS MR4 review gate with conceptual study serving as foundation of design basis memorandum (DBM)

Key Project Milestones (2)

- **March 2010 – Dulang Redevelopment concept redefined in-house and project team formed**
  - Several positions not filled
  - Project manager appointed from Dulang Compression Project
- **January 2011 – Decision made to authorise Phase 1 early to accelerate incremental oil production and make use of rig and HUC availability**
- **May 2011 – PMU approved Dulang Redevelopment Phase 1 technical proposal**
- **July 2011 – EVP of PETRONAS E&P approval of Phase 1 – official project sanction**
- **Mid 2011 – Change of PETRONAS business strategy to use KM1 rig for Angsi well prior to Phase 1 wells**

Key Project Milestones (3)

- February 2012 – Arrival of KM1 rig 5 months later than planned
  - Rig held up on previous Angsi well after stuck pipe incident
- April 2012 – First oil from Dulang D Platform
- October 2013 – First oil from Dulang C Platform
- April 2013 – First oil from Dulang A Platform
- August 2013 – First oil from Dulang B Platform
- August 2013 – Drilling and completion of Phase 1 wells finishes
- September 2013 – Complete final offshore hook-up and commissioning

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- **Practices and Drivers**
- **Outcomes**
- **Conclusions and Lessons Learned**

Capital Effectiveness:
Project Inputs Drive Project Outcomes

Project Drivers

- Front-End Loading
- Value Improving Practices
- Technical Innovation
- Team Development

Project Discipline

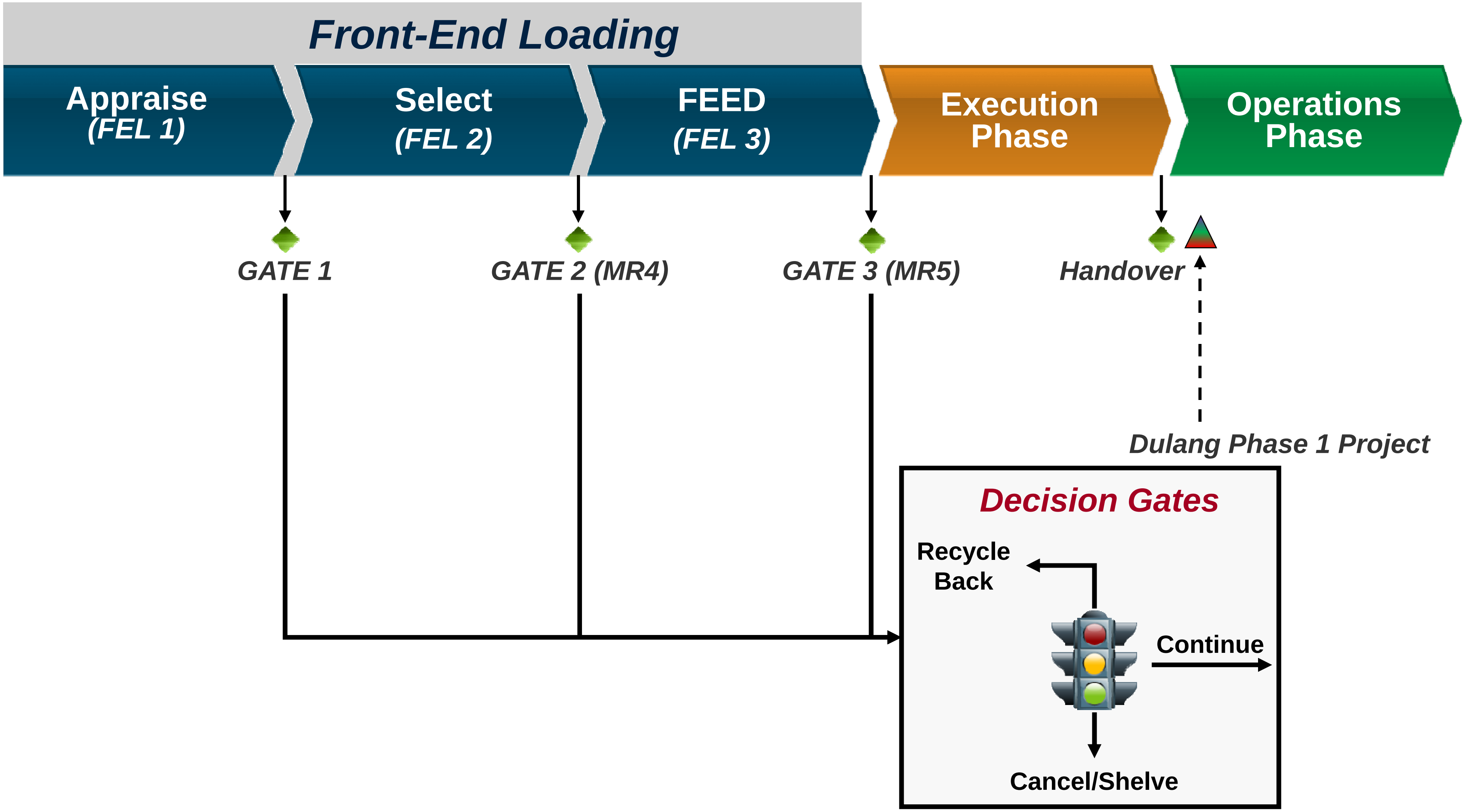
- Controls and Changes
- Turnover

Practices Lead to Outcomes

Project Outcomes

- Cost
- Schedule
- Operability
- Safety

Three Phases of Front-End Loading



IPA Project Analysis Process

Data Collection

- Complete literature search and review documentation sent prior to interview
- Interview project team members on 12 and 13 September 2013
- Complete IPA benchmarking workbooks
- Review project documentation

Analysis

- Identify similar industry projects as basis of comparison
- Normalise data for time and location
- Analyse project, including running models
- Use comparison dataset to further understand project risks
- Apply relevant research
- Review analysis

Results Delivery

- Prepare deliverable
- Complete edit and review of deliverable
- Issue Draft
- Discuss findings with project team
- Allow team to comment on Draft
- Issue Final deliverable within 2 weeks of Draft

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Basis of Comparison

- **Projects selected from IPA upstream database used to establish valid basis of comparison for Dulang Phase 1 Project**
  - **Recently completed large Industry projects from UIBC 2012***
  - **Most recently completed PETRONAS projects from UIBC 2012**
  - **Comparison dataset of global projects used to model wells scope after controlling for project characteristics**
  - **Comparison datasets of similar Asian projects used to validate wells analysis**

*** UIBC 2012 = annual meeting of the Upstream Industry Benchmarking Consortium in November 2012. The UIBC is a voluntary association of owner firms in the upstream and midstream industry that use IPA's quantitative benchmarking approach. The members exchange data, information, and metrics to improve the effectiveness of their project systems.**

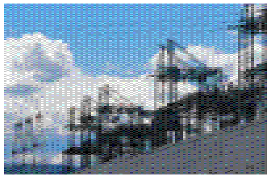
IPA Proprietary Databases

PES SMALL PROJECTS
6,000+ projects
Projects <$8MM from process industries

PROCESS PLANTS PES
15,000+ projects
Detailed histories of process plant projects >$5MM

HAZRISK
400+ projects
Environmental assessments and cleanups

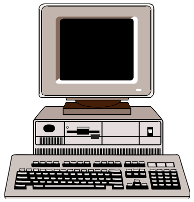
MEGAPROJECTS
250+ projects
$Billion class projects, all types



POWER PLANTS
>50 projects
Single or combined cycle plants

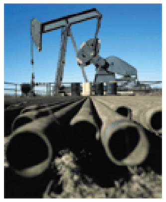
PLANNED TURNAROUNDS
200+ projects
Facility turnarounds

INFORMATION TECHNOLOGY
250+ projects; including Applications development, Telecommunication, etc.



INSTRUMENTATION & CONTROL
70+ projects
Automation, DCS, SCADA, etc.

UPSTREAM PES
1,500+ projects
Platform, Subsea, Floaters, Subsurface, Drilling



PIPELINES
500+ projects
Pipelines, terminals, booster stations, etc.

Operators in IPA's E&P Benchmarking

Majors and Independents

Anadarko
Apache
BG Group
BHP Billiton
ConocoPhillips
Hess
INPEX
Lundin
Marathon
Medco Energi
Nexen
Noble Energy
Oando
Pioneer
Santos
Sasol E&P
Talisman Energy
W&T Offshore
Woodside

National Oil Companies or Partial State Ownership

ADNOC
ADDAX
AIOC
CNOOC
DONG
ENI
Ecopetrol
LukOil
Mubadala
Oman Oil
OMV
PDVSA
PDO
Petrobras
Petrochina
PETRONAS
PTTEP
Repsol
Saudi Aramco
Statoil

Super Majors

BP
Chevron
ExxonMobil
Shell
Total

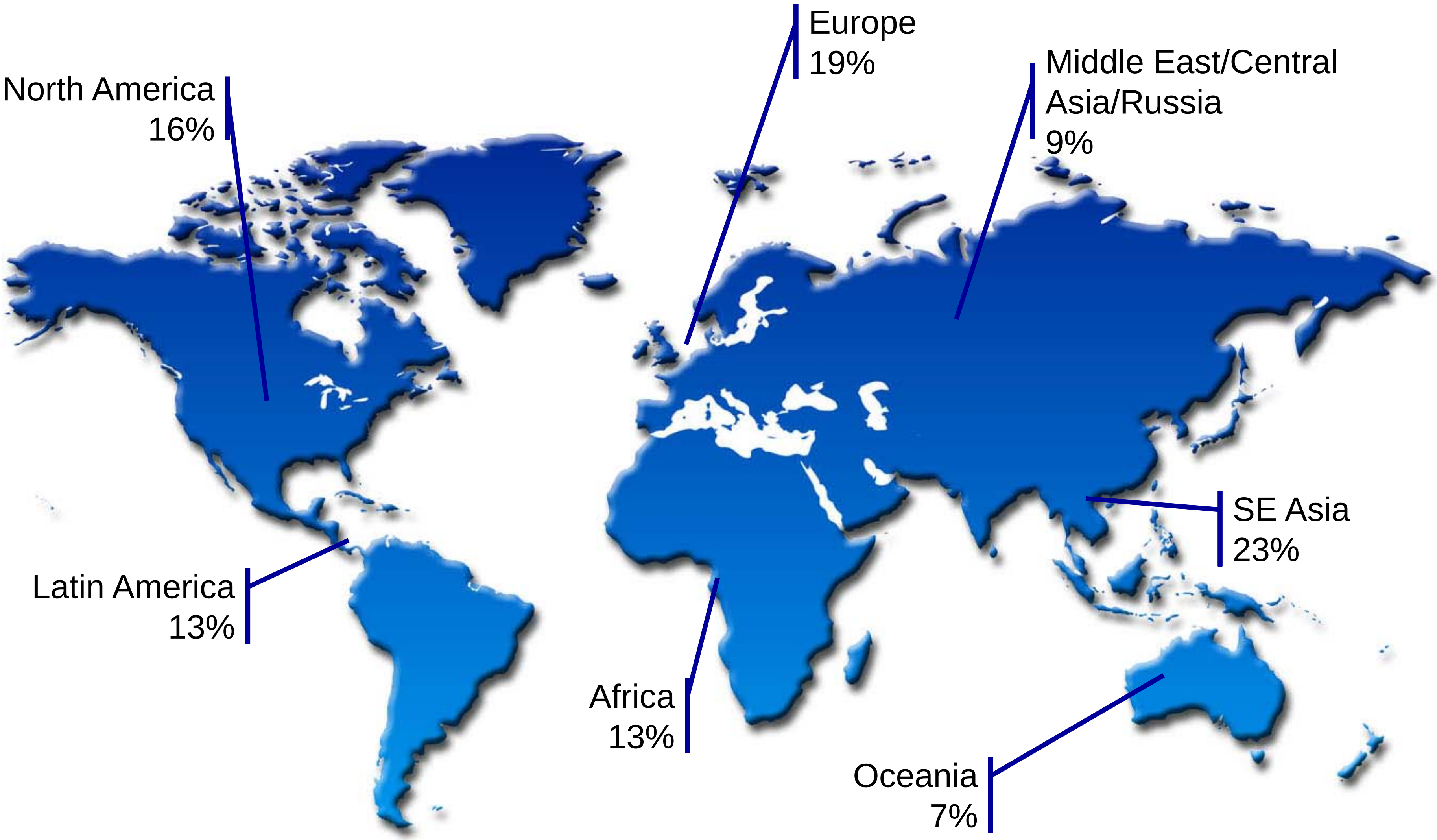
** Company names in red indicate IBC and/or UIBC member companies*

Basis of Comparison—UIBC 2012 Database

Characteristic	Dulang Phase 1 Project	Dataset (404 projects)		
		Minimum	Median	Maximum
Year of Sanction	2011	2004	2007	2012
Average Facility Cost (^{2013} RM million)	172	<15	3,060	36,400
Average Well Program Cost (^{2013} RM million)	713	<15	2,140	20,400
Water Depth (m)	76	<300 m, 70%; 300 m to 900 m, 11%; >900 m, 19%		
Concept Type	Wells	18% subsea, 19% onshore, 10% floater, 26% platform, 11% revamp, 15% other		

- **Analysis based on models and comparisons that draw on IPA Upstream Database, which includes more than 1,500 projects**
- **We used a recent subset of projects to establish industry drivers and benchmarks for Dulang Phase 1 Project**

UIBC 2012 Project Geographical Distribution



Basis of Comparison: Well Construction Model

Characteristic	Dulang Phase 1 Project	Dataset (297 projects)		
		Minimum	Median	Maximum
Year of Authorisation	2011	1990	2001	2008
Region	Asia	North America, 21%; Europe, 35%; Africa, 12%; South America, 14%; Oceania, 8%; Asia, 10%		
Cost (RM^{2013} million)	661	13	1,809	>2,000
Water Depth (m)	76	3	120	2,900
Post-Startup Life-of-Project Production Stream (MMBOE)	Est: 25.0	2	90	5,00

Asian Wells Comparison* Basis of Comparison

Characteristic	Dulang Phase 1 Project	Dataset (27 projects)		
		Minimum	Mean	Maximum
Year of Authorisation	2011	1992	2006	2012
Region	Malaysia	Southeast Asia, 100 percent		
Cost (RM^{2013} million)	661	220	980	5,500
Water Depth (m)	76	36	99	300
Program Duration (days)	457	56	199	490

** Comparison dataset excludes well programs executed in Thailand*

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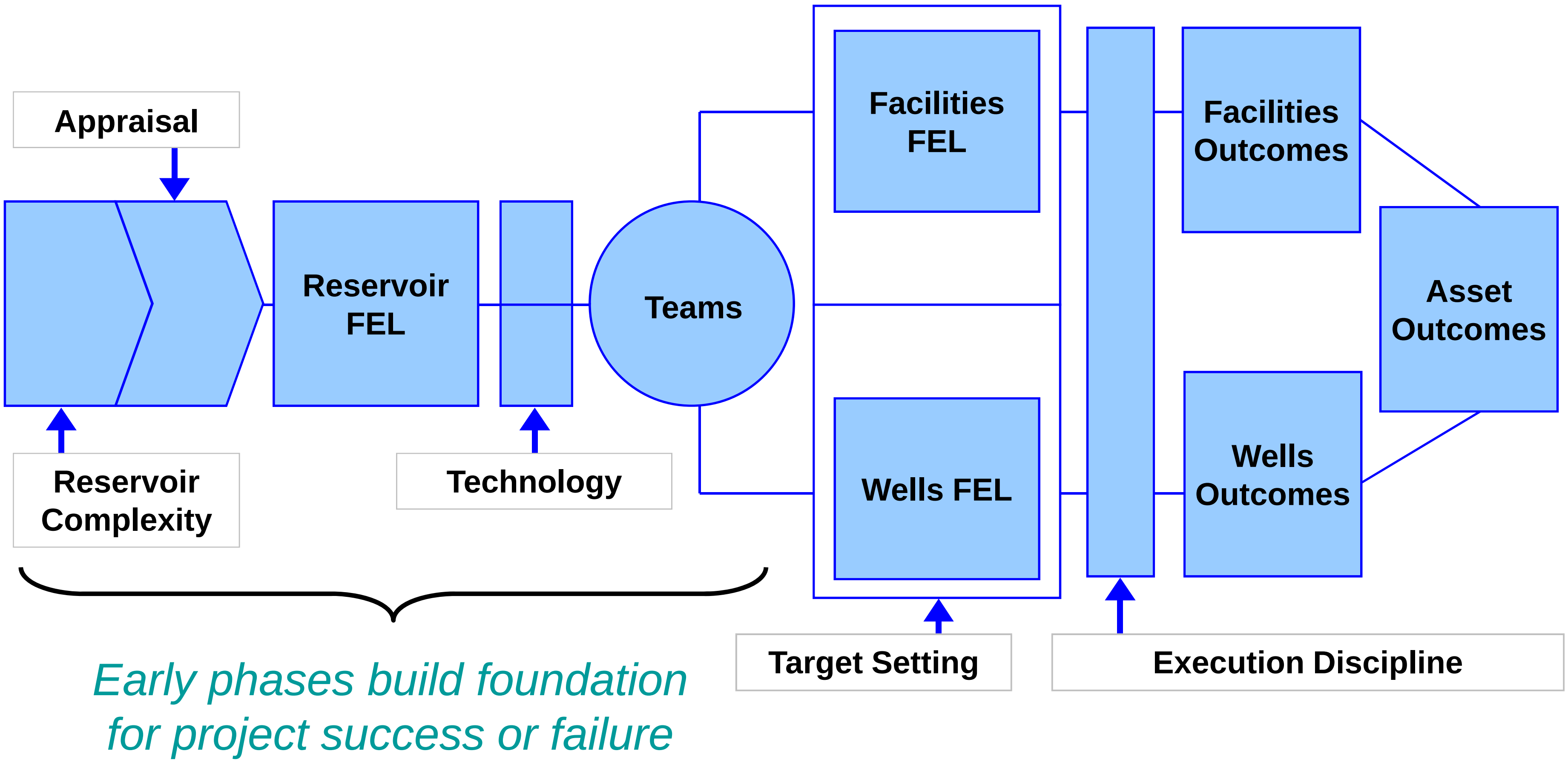
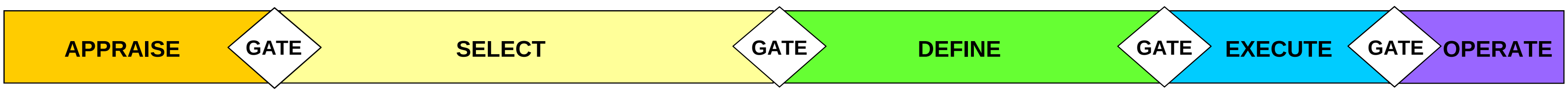
Building a Pathway to Project Success

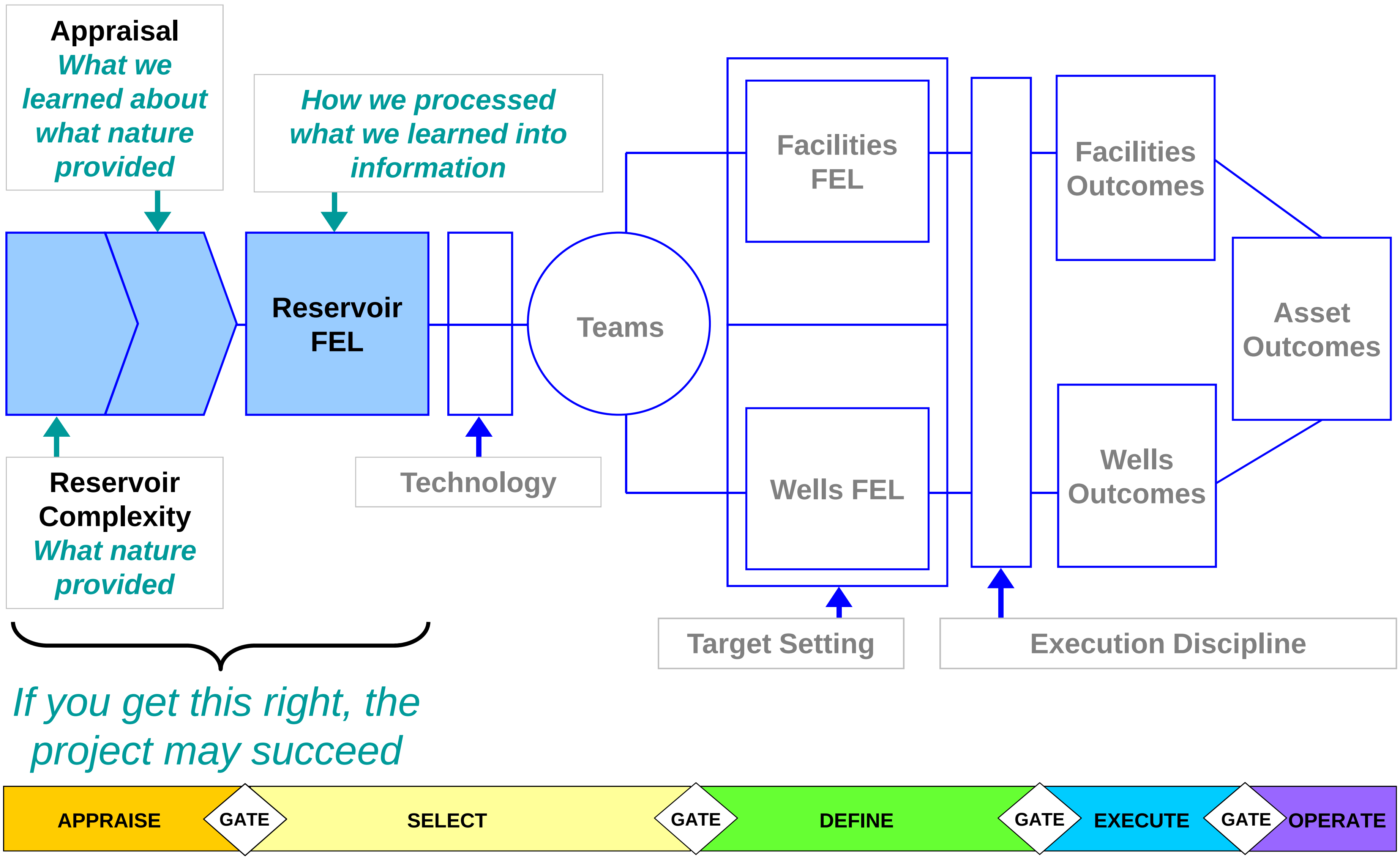
There Is a Necessary Sequence; Foundation Must Be Solid



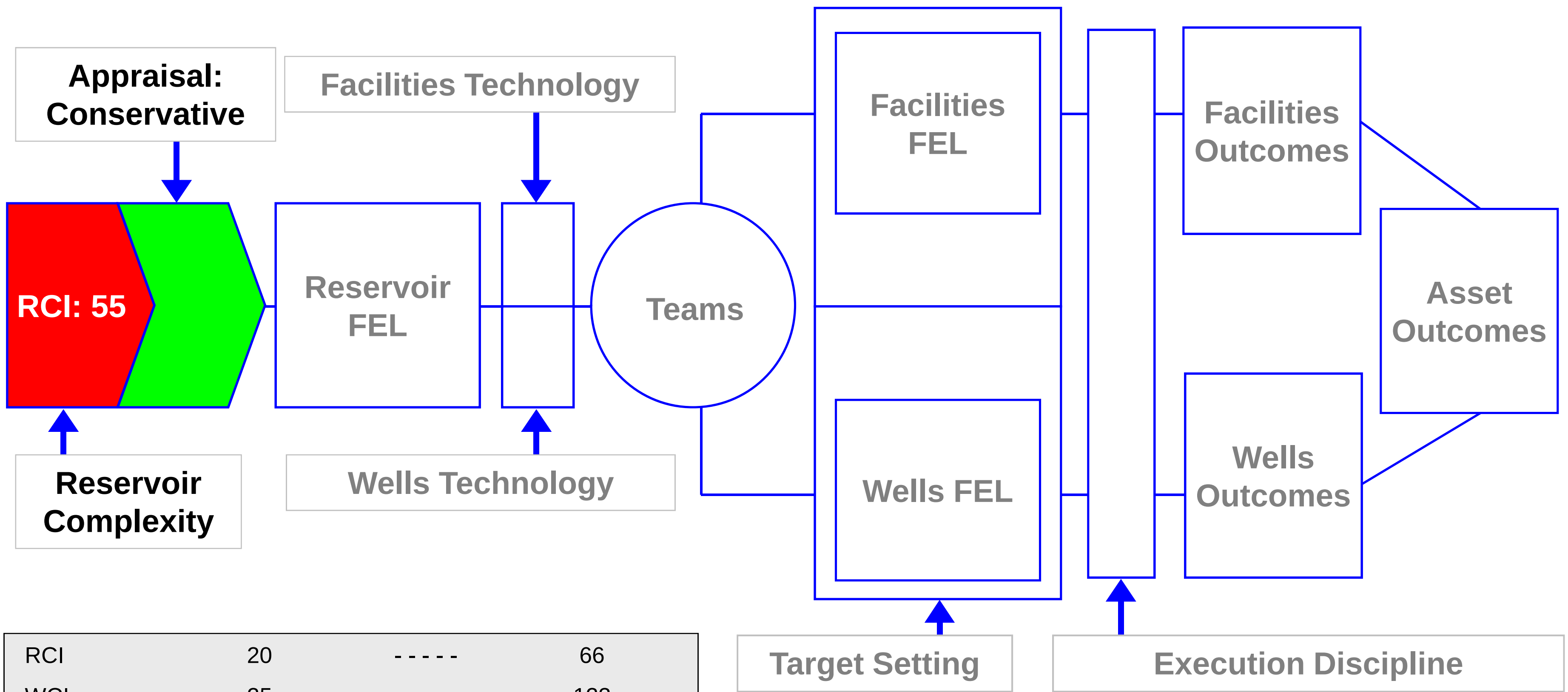


Reservoir FEL Is Best Predictor of Asset Outcomes

Failure to Understand Leads to Suboptimal Development



Complex Reservoir, Conservative Appraisal



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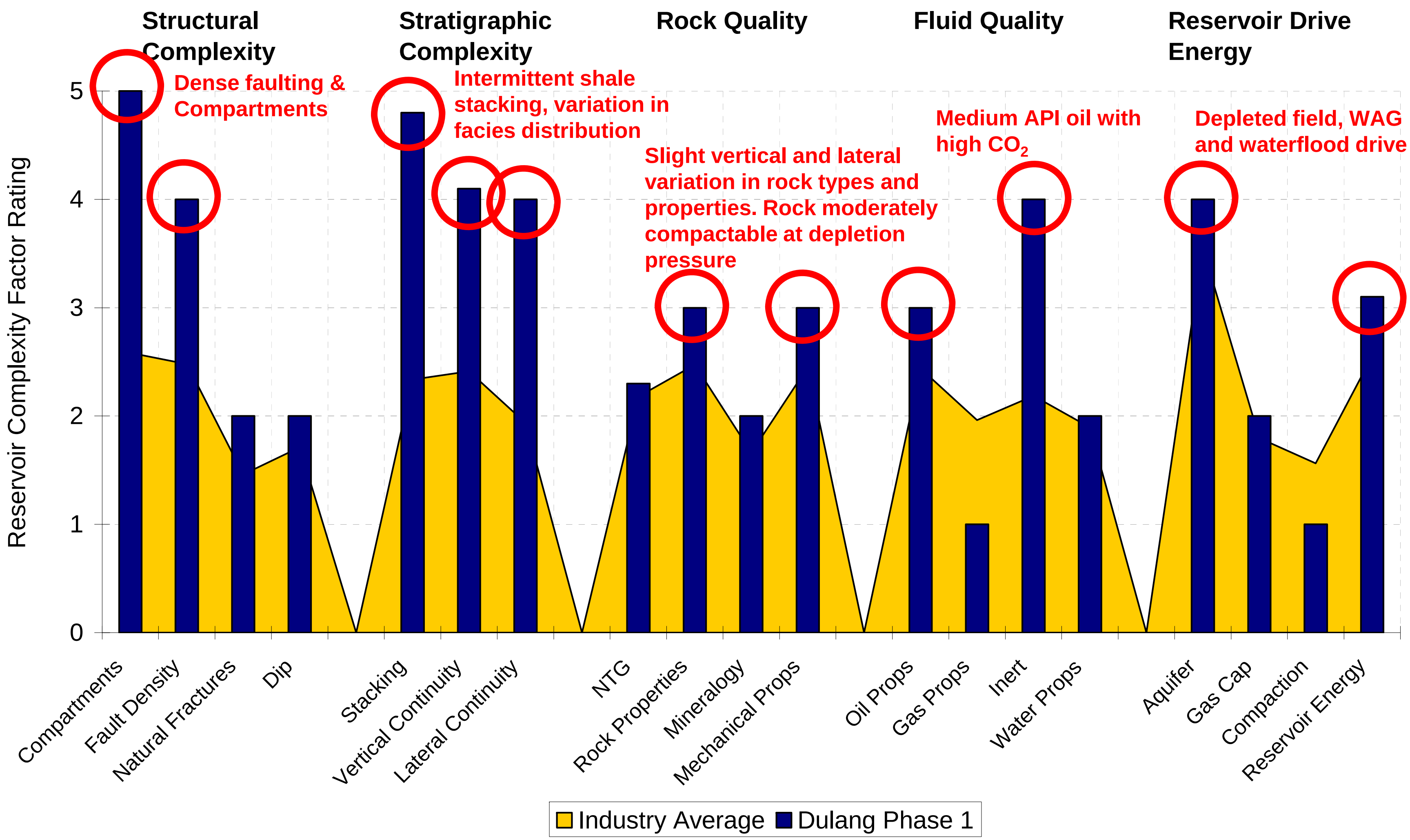
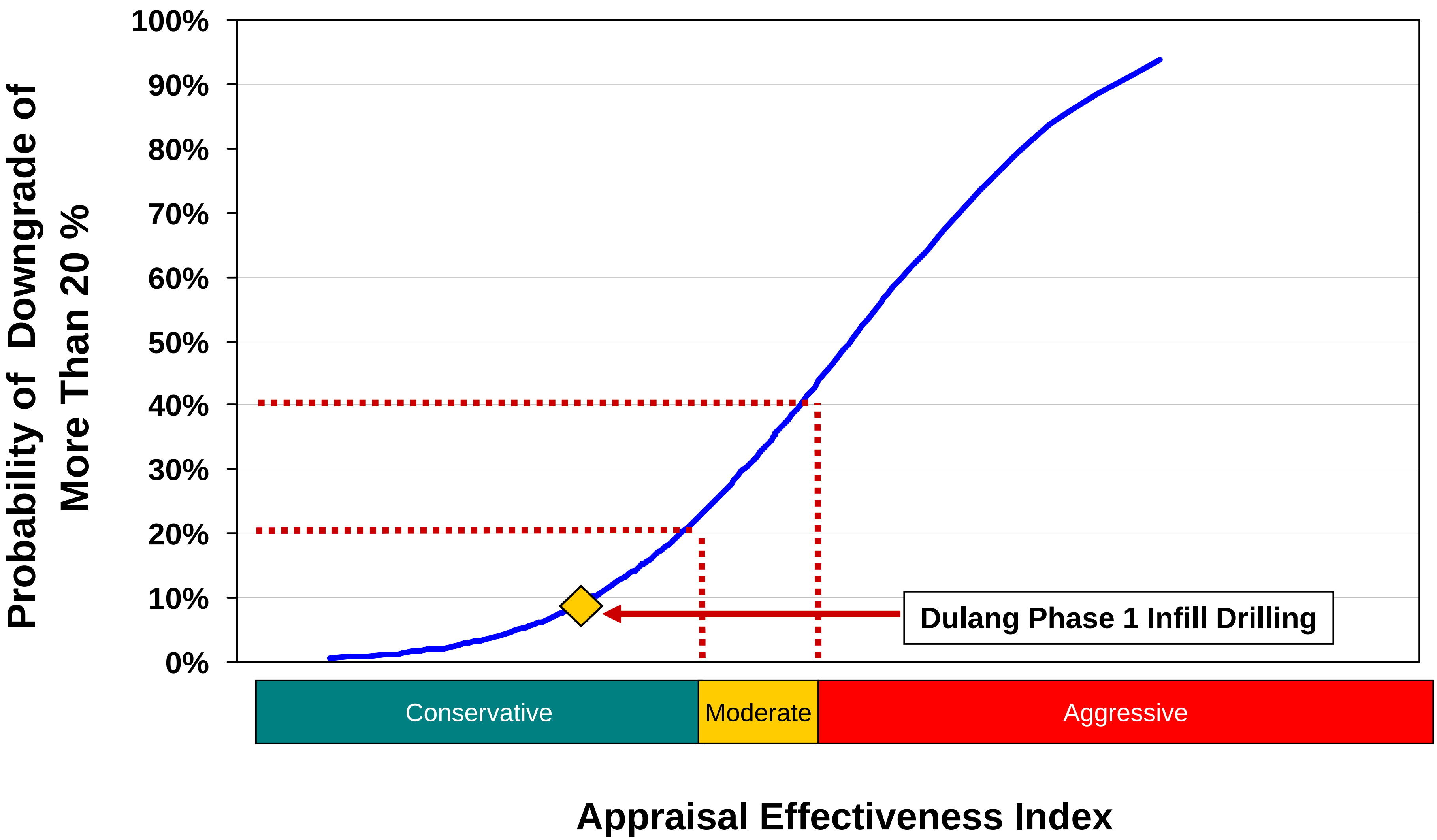
Dulang Field's High Reservoir Complexity Influenced Development



Appraisal Effectiveness Index

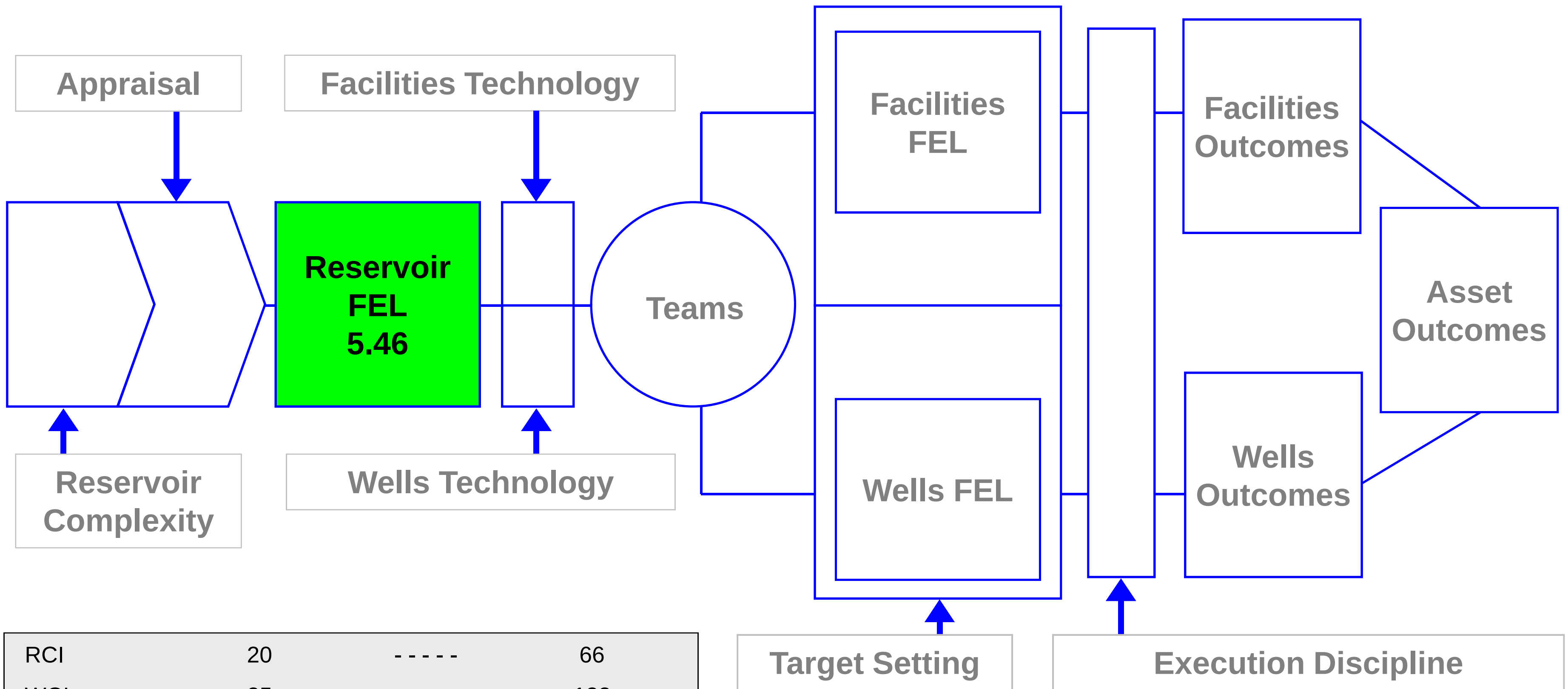
Phase 1 Faced Low Risk of Recovery Downgrade



Appraisal Effectiveness Index

- **Seismic of moderate quality form 2002 used for Phase 1 planning**
  - **New seismic shot in 2010 processed late in FEL 3 was not available for authorisation decision**
- **148 producing wells in Dulang field with vast amounts of data available for log and core analysis**
  - **Static properties very well established around infill drilling locations**
- **20 years of production history in Dulang meant fluid properties were well understood in most sands**
- **Dynamic uncertainty around WAG sweep efficiency and field compartmentalisation**
  - **Although production trends of existing wells served as good reference points for real production data**

Good Reservoir FEL
Industry Average Reservoir FEL



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Reservoir Front-End Loading

Inputs

- Seismic
- Logs
- Cores/SCAL
- Fluid Properties
- Well & Reservoir Tests
- Pressures
- Production History Analogues

Constraints

- Regulatory/ Environmental
- Timing
- Budget
- Appraisal Strategy
- Operating Constraints
- Technology/ Tolerance for Risk
- Business Commercial Strategy Issues
- Joint Operating Agreement Issues

Tasks

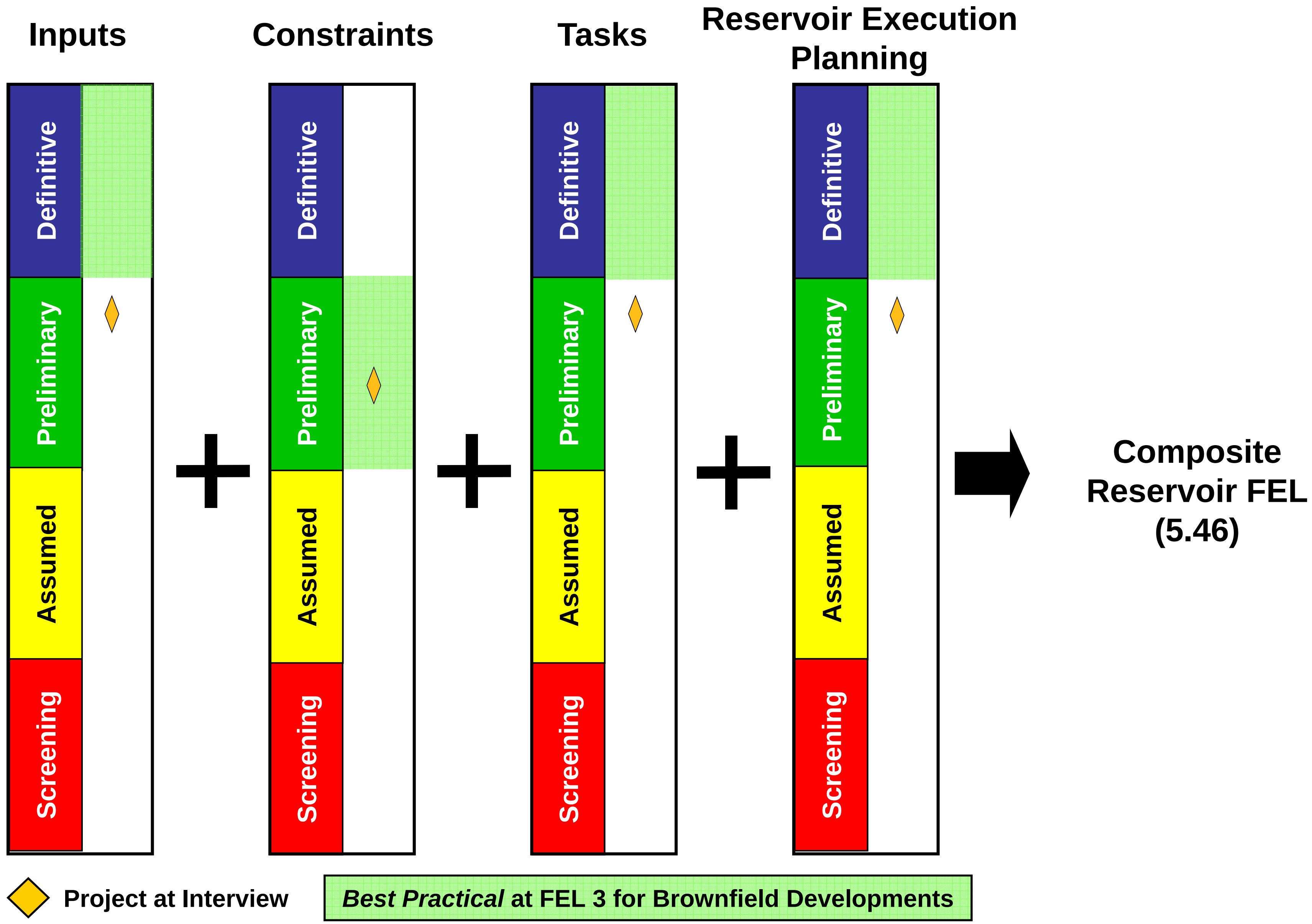
- Interpret Seismic
- Develop Maps and Geologic Model
- Integrate Wells Team
- Characterise Fluids
- Complete Reservoir Design Basis
- Understand Drive Mechanism
- Define Compartments
- Predict Production Profiles and Reserves
- Complete Risk and Uncertainty Analysis

Execution Planning

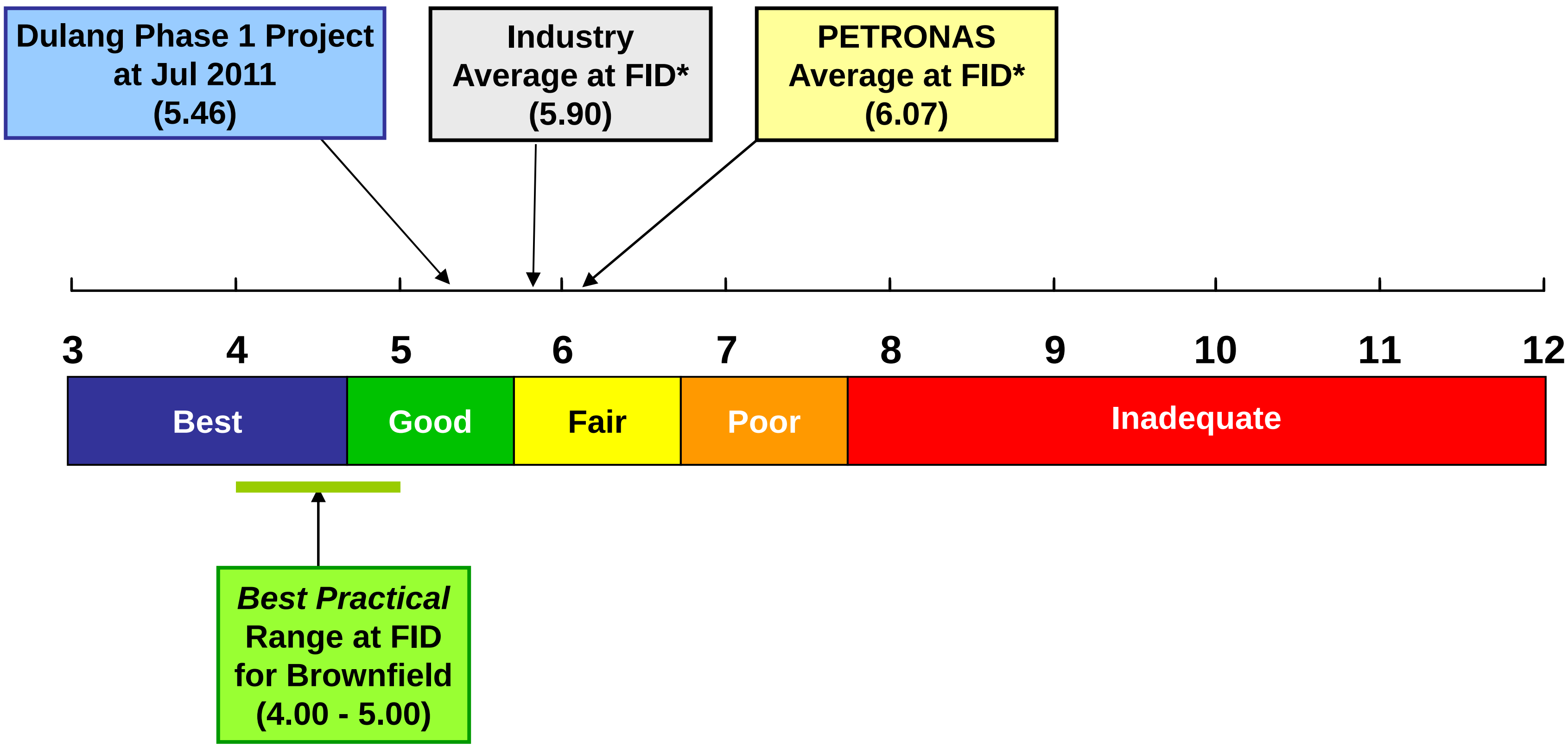
- Subsurface Team Interactions
- Schedule Development
- Plans/Documents Completed
- Controls in Place

Reservoir FEL by Component

Most Components Lagged Best Practical – But Close



Dulang Phase 1 Project Reservoir FEL Lagged Brownfield *Best Practical*



* From Upstream Industry Benchmarking Consortium - UIBC 2012

Inputs Were *Preliminary*

- **Lagged *Best Practical* rating of *Definitive***
- **Field producing for 20 years with 148 wells**
- **2002 3D seismic data marred by shallow gas and multiple coal stacks**
- **Cores taken in 1980s and 1990s**
- **Dense faulting and compartmentalisation less understood—fluid properties may vary**
- **Pressure data only available for key compartments**

Constraints Were *Preliminary*

- ***Best Practical*** **rating at authorisation**
- **No major issues**
- **Production sharing contract ends in 2021**
  - **Project team assumed current terms continue post 2021**

Tasks Were *Preliminary*

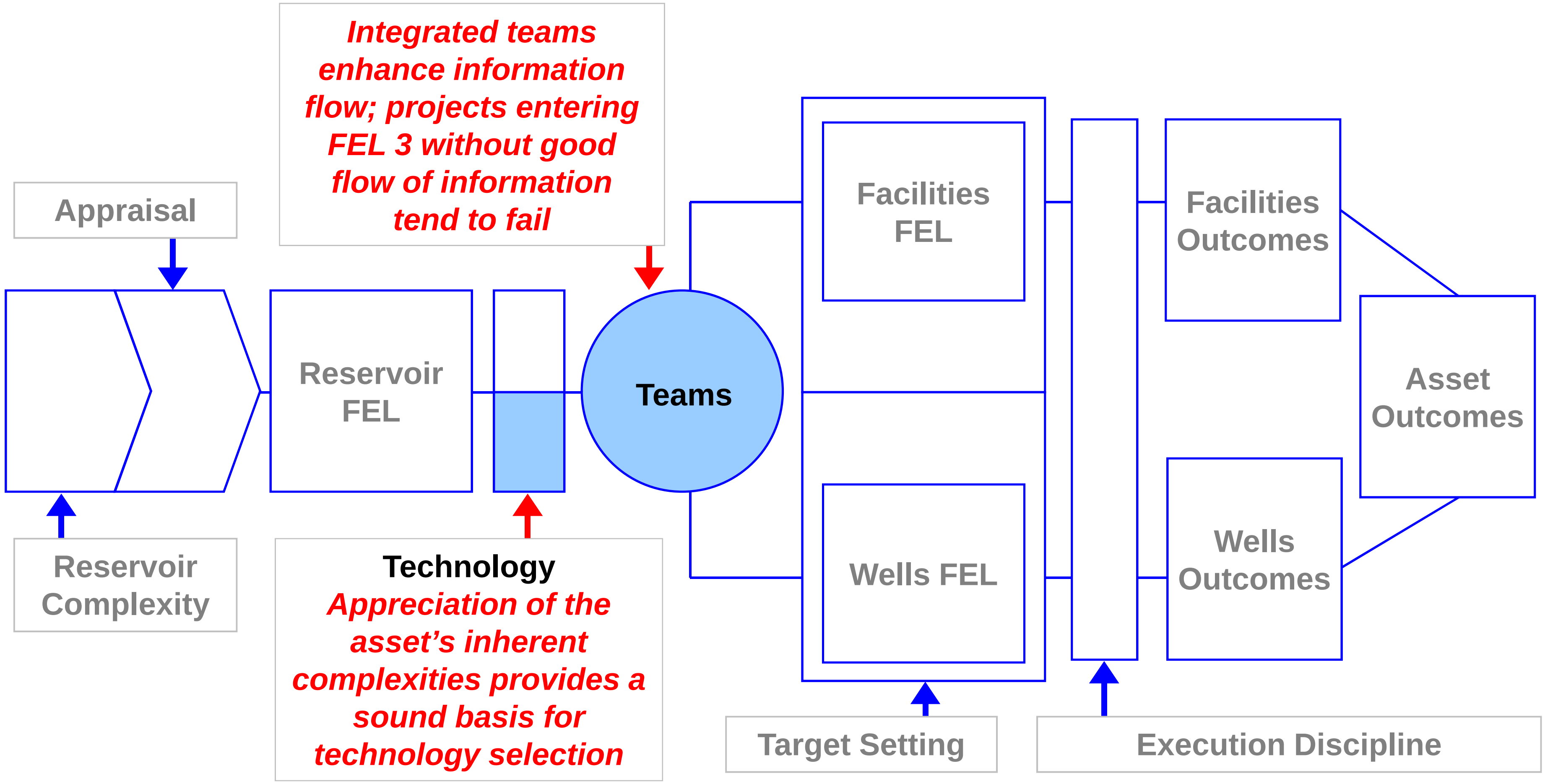
- **Lagged *Best Practical* rating of *Definitive***
- **Risk and uncertainties analysis completed**
- **Reservoir drive mechanism understood**
- **Reservoir compartmentalisation mapped from seismic data and pressure data however;**
  - **2010 3D seismic not incorporated into geologic model by sanction**
- **Detailed subsurface activity schedule not developed and incorporated into overall integrated project schedule**

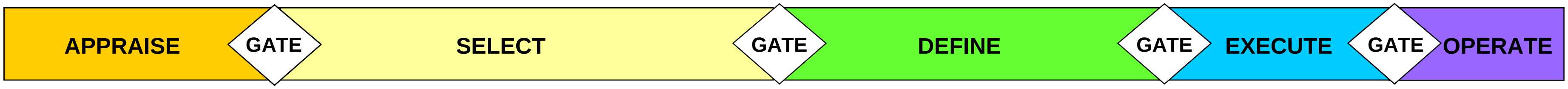
Execution Planning Was *Preliminary*

- **Lagged *Best Practical* rating of *Definitive***
- **Technical Proposal submitted January 2011 and approved in May 2011 prior to authorisation**
- **Full team established, but some members only part-time for project; head of subsurface joined prior to authorisation in April 2011**
- **Data acquisition and reservoir surveillance planning finalised prior to authorisation in April 2011**
- **Risks and uncertainties recognised but not fully integrated into forward planning of reservoir development plan by sanction**
- **Procedure for production allocation for WAG production increase not final at authorisation**

Reservoir Knowledge Drives Concept Select Basis

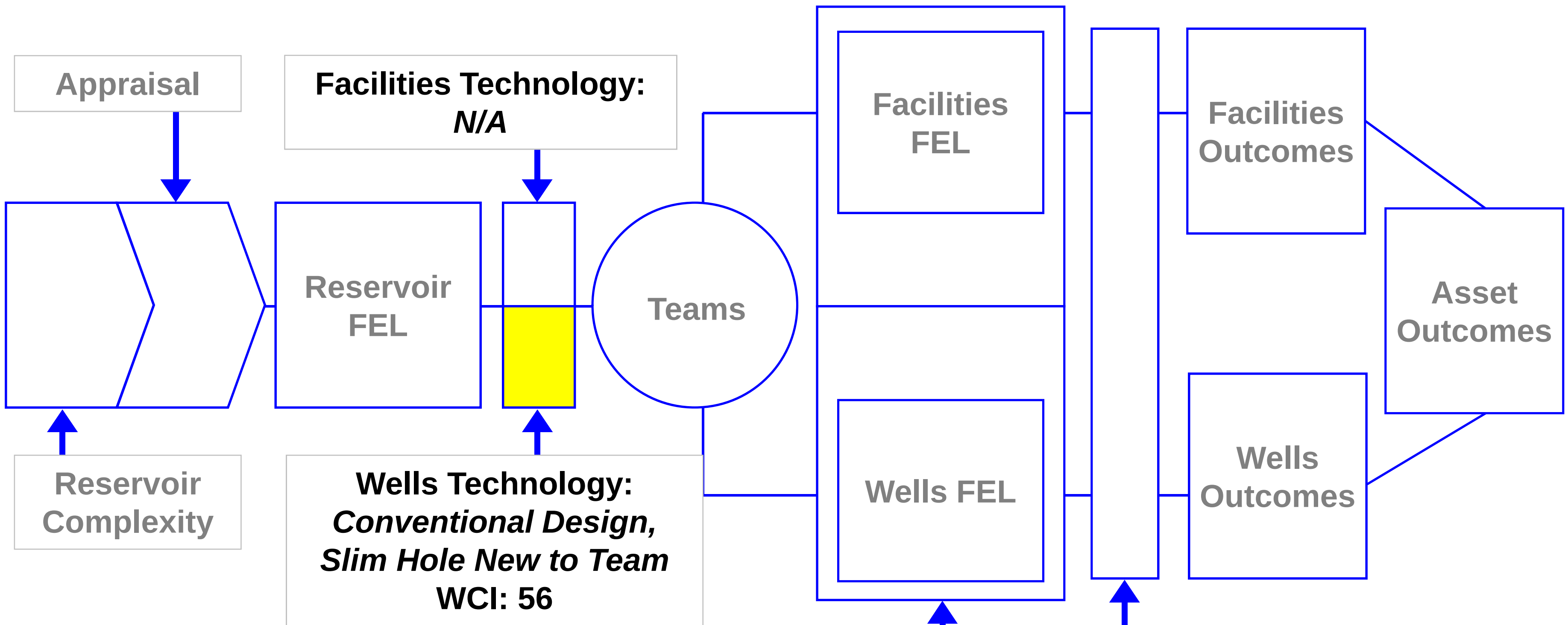
Development Plan Drives Choice of Effective Team





Industry Average Wells Complexity

Conventional but New to Team Wells Technology



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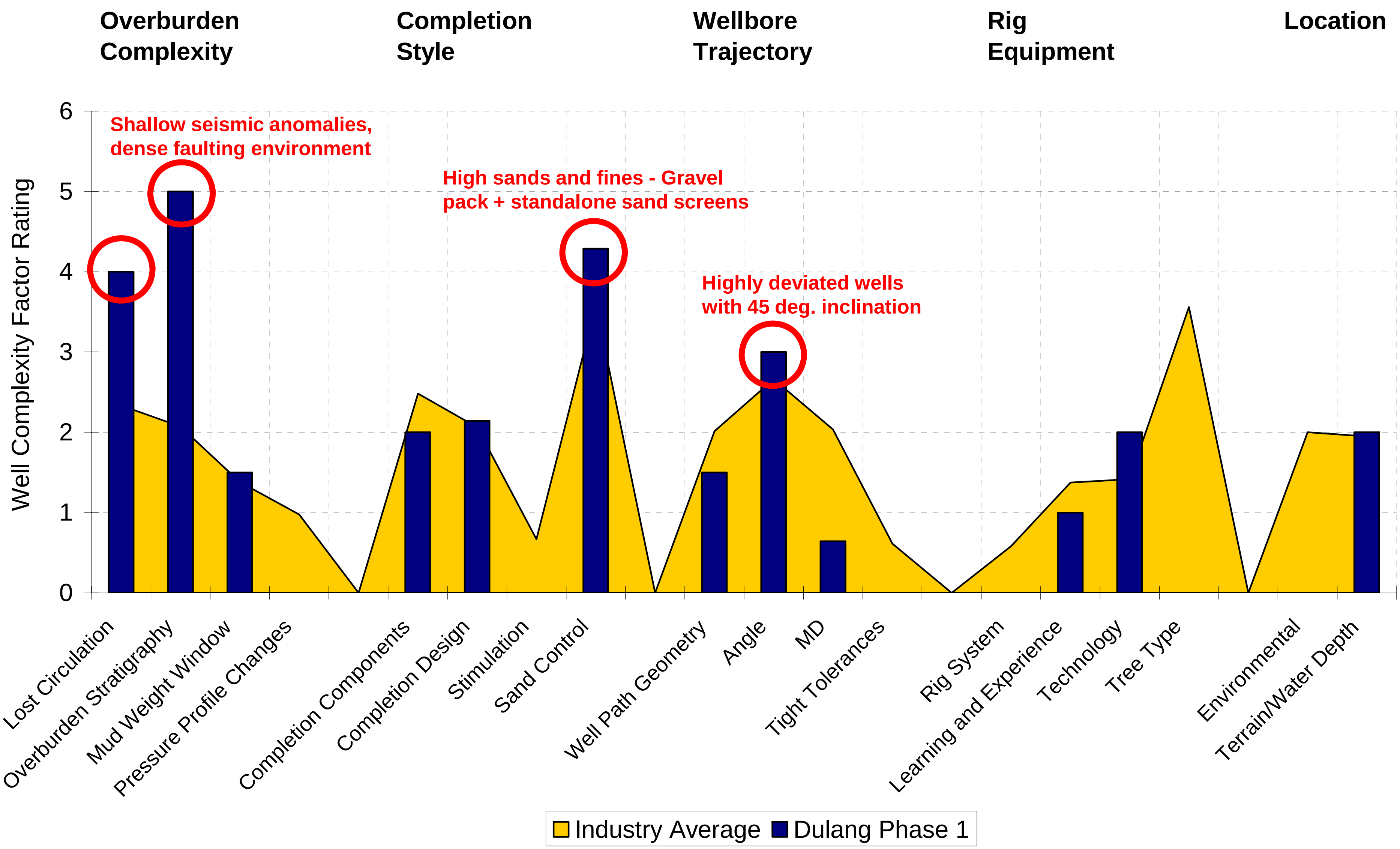
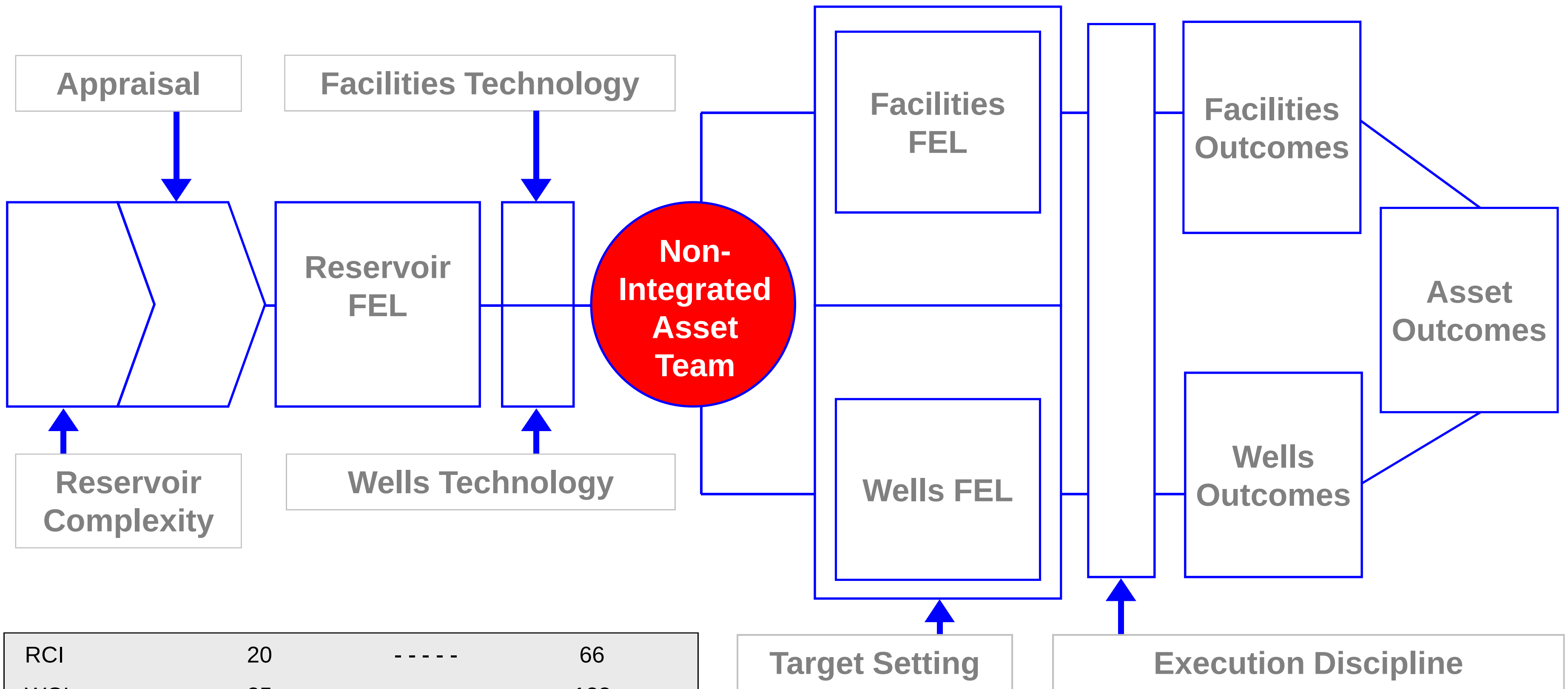
Dulang Phase 1 Had Average Well Complexity

Well Complexity Index (WCI) of 56 – Industry Average 55



Drivers of Project Success
Asset Team Not Integrated



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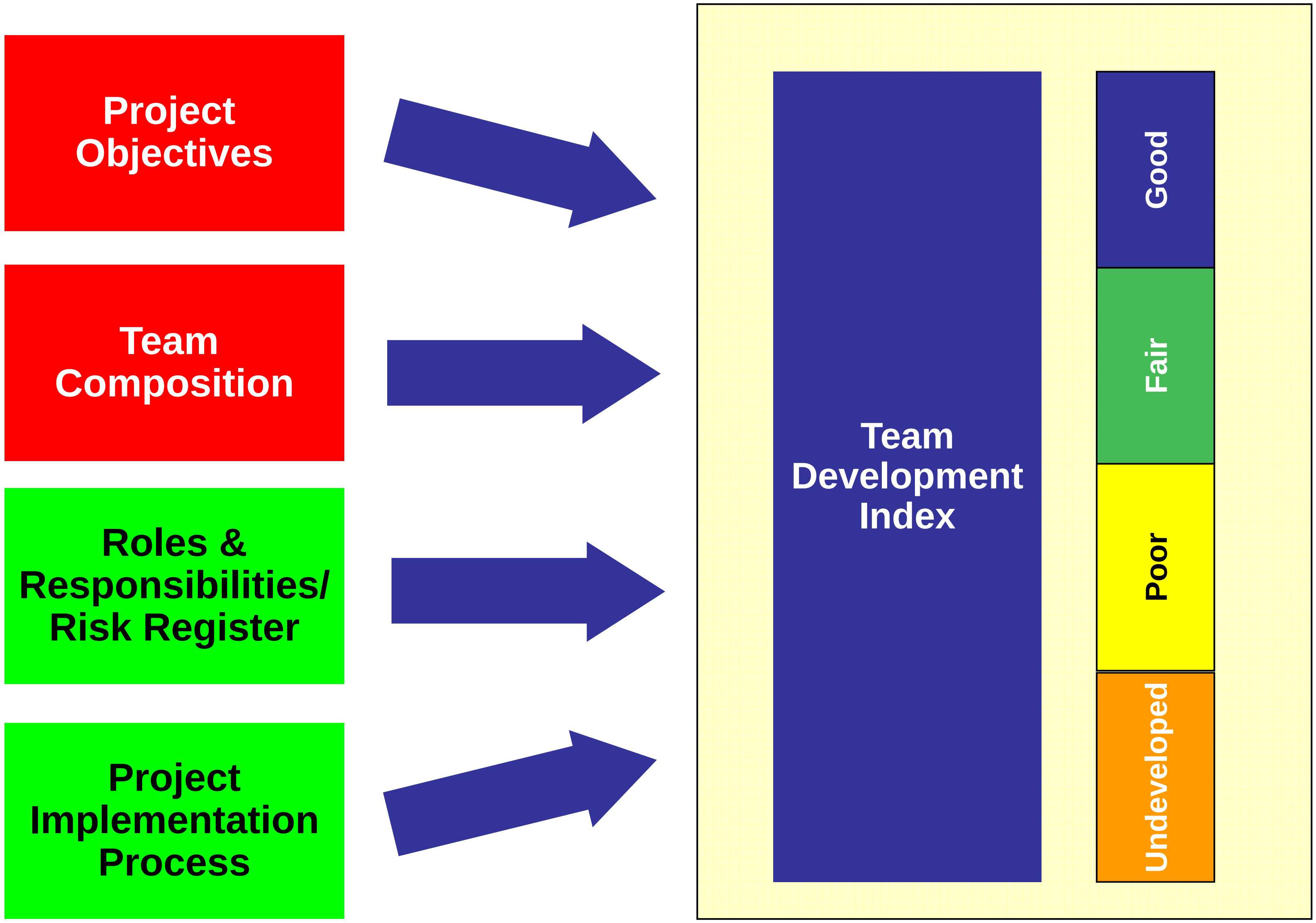
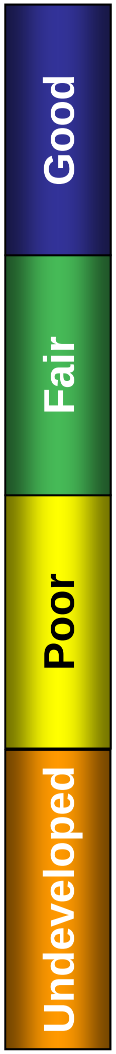
Team Development Index (TDI) Measures Process That Aligns the Team



Dulang Phase 1 Project TDI Was *Poor* at Authorisation (1)



- Industry Average
- Dulang Phase 1 Project at Authorisation

☒*Business and project objectives*

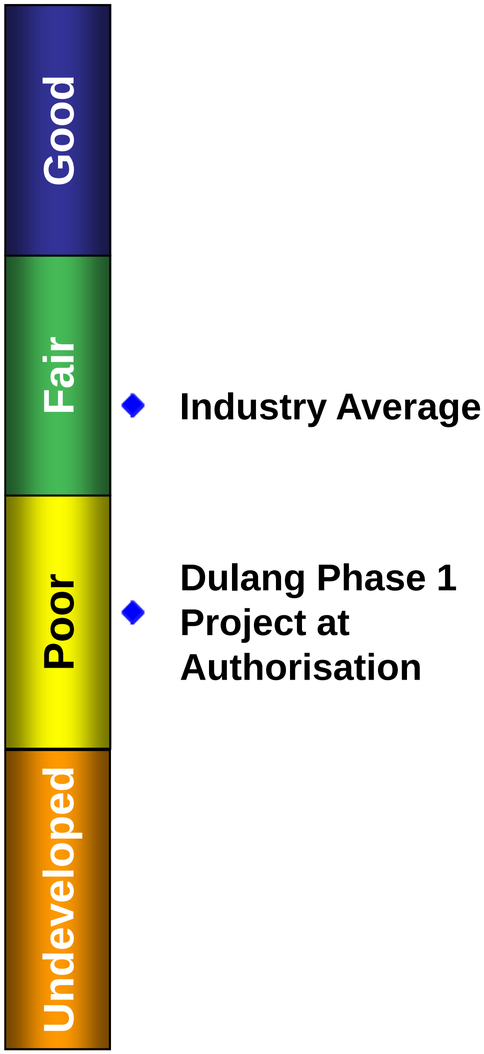
- **High level objective to increase oil production via WAG EOR concept understood and well communicated**
- **Clear scope identified to achieve high level objective**
  - **Lack of clarity around how production success was to be quantified at time of authorisation**
    - **Since authorisation, process has been further defined**
- **Trade-offs among cost, schedule, and production not documented for project members**
  - **Value decisions made on an as needed basis**

Effects of Clear Business Goals on Project Outcomes

Project Outcomes	Delta
Cost	- 5%
Cost growth	-7%
Cycle time	-17%
Execution time	-19%
Schedule slip	-18%
First year production	+9%

Source: E.W. Merrow, *Managing the Business of Capital Projects*, IPA, 2004

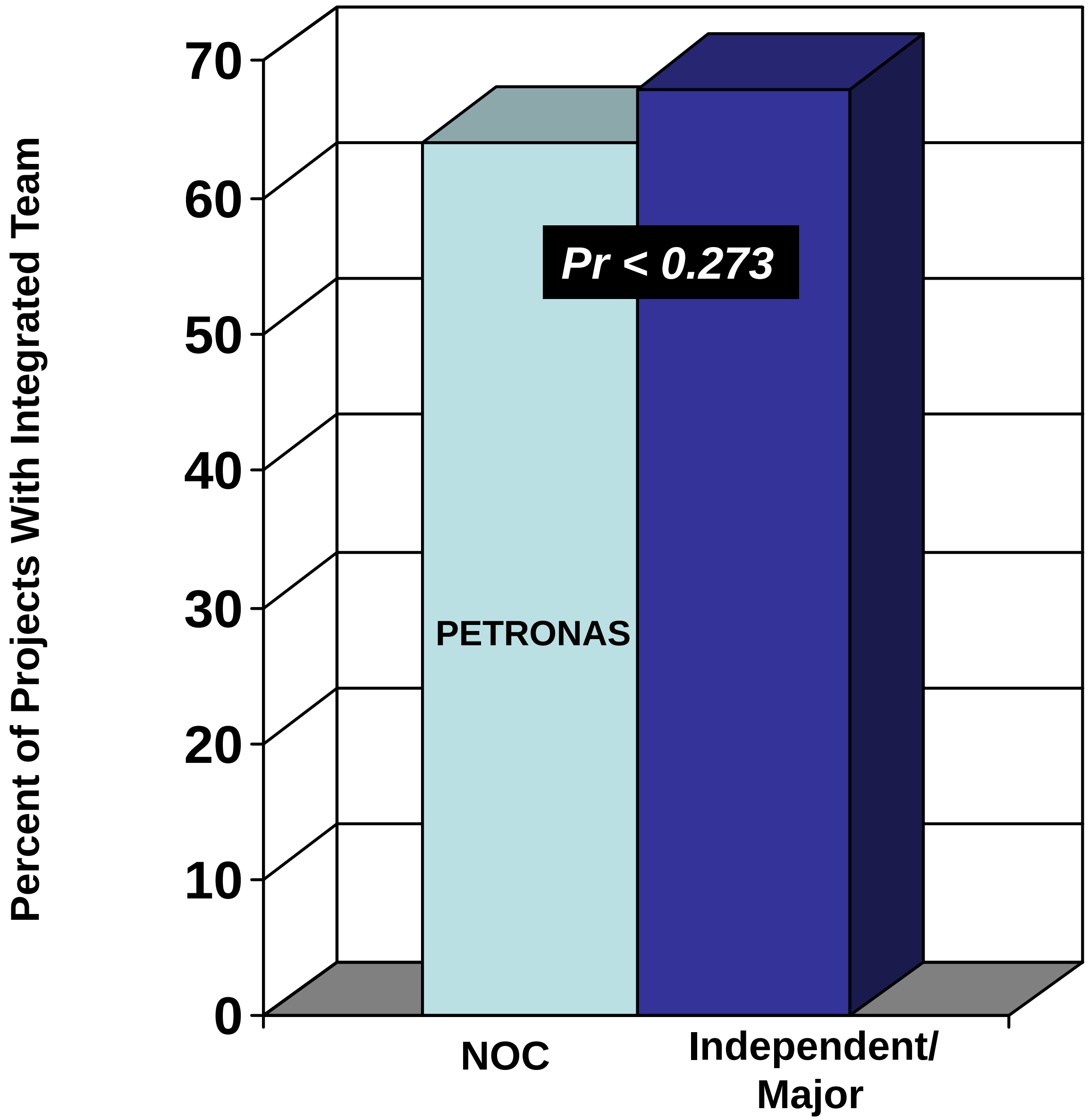
Dulang Phase 1 Project TDI Was *Poor* at Authorisation (2)



☒ *Team integration*

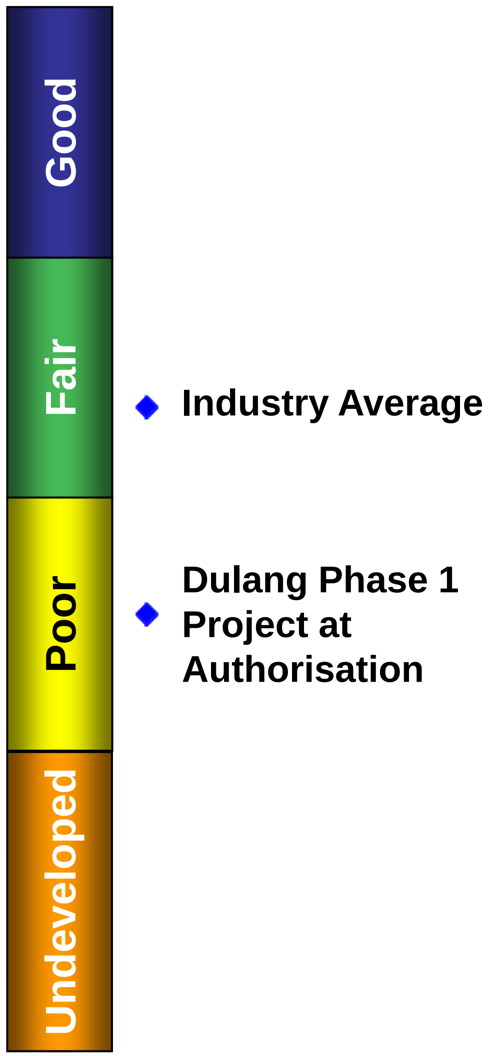
- **Head of subsurface and head of drilling vacant during FEL 2 and FEL 3**
- **Involvement of operations minimal and ad hoc during early project phases**
  - **Ops rep available but not residing with team**
- **Gaps filled during execution**
  - **But involvement during planning assures key decision makers' input into scope, cost, and schedule**

Being a NOC* Does *NOT* Limit Your Ability to Form an Integrated Team



*NOC = National Oil Company

Dulang Phase 1 Project TDI Was *Poor* at Authorisation (3)



☑ ***Roles and responsibilities***

– **Team members understood roles and responsibilities given the functional project nature**

– **Team aligned on who does what and when**

☑ ***Major risks and problems identified***

– **Detailed project risk document established during planning stages for Phase 1 and 2**

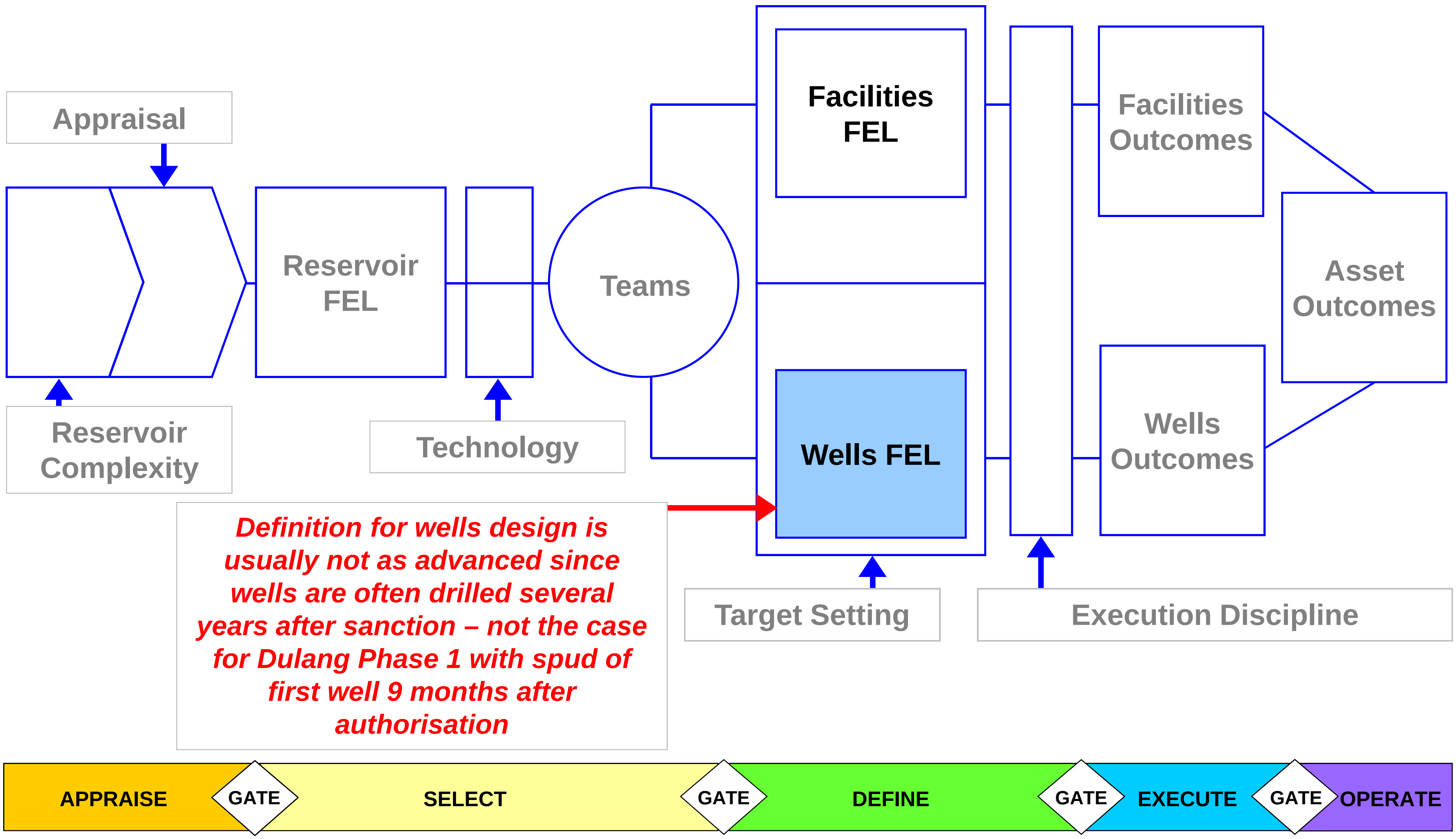
– **Subsurface risk and uncertainty workshop held for Phase 1 alone (after sanction)**

  - **Excellent Best Practice but seldom done**

☑ ***Detailed authorisation process used***

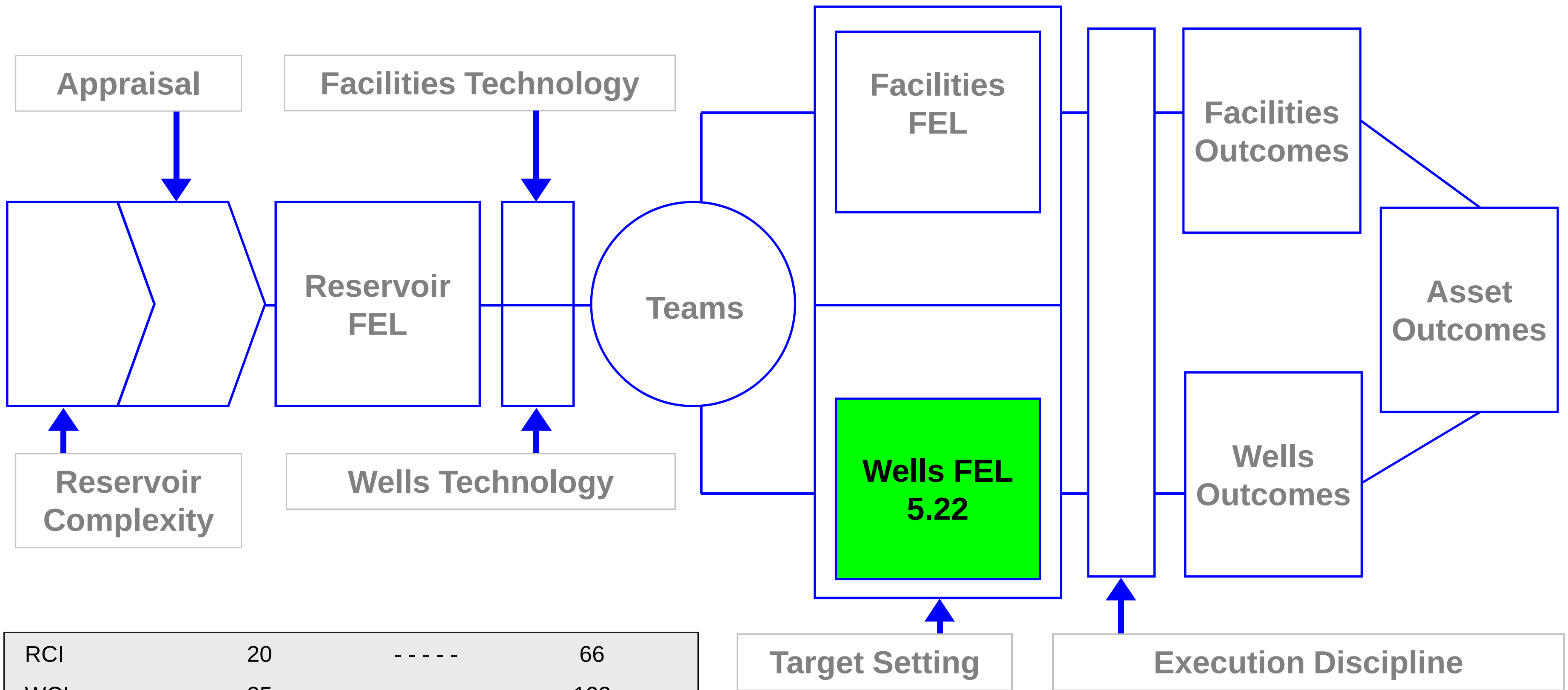
– **Project team followed the PETRONAS Project Management System (PPMS)**

FEL Is Important Driver of Core Project Performance
Enables but Does Not Determine Project Success



Drivers of Project Success

Phase 1 Wells FEL



RCI	20	- - - - -	66
WCI	25	- - - - -	123
Risk	<<< Less	- - - - -	More >>>
Results	<<< Better	- - - - -	Worse >>>
	Low	Medium	High

Wells Front-End Loading

Scope of Work	Regulatory HSE	Well Engineering	Execution Planning

Scope of Work

- Offset Wells
- Commercial
- Well Objectives
- Scope of Work
- Location Survey
- Metocean Data
- All Needed Technical Inputs

Regulatory HSE

- Permitting
- Preliminary Safety Management Plan
- Hazard Analysis
- Company Policies
- Waste Management

Well Engineering

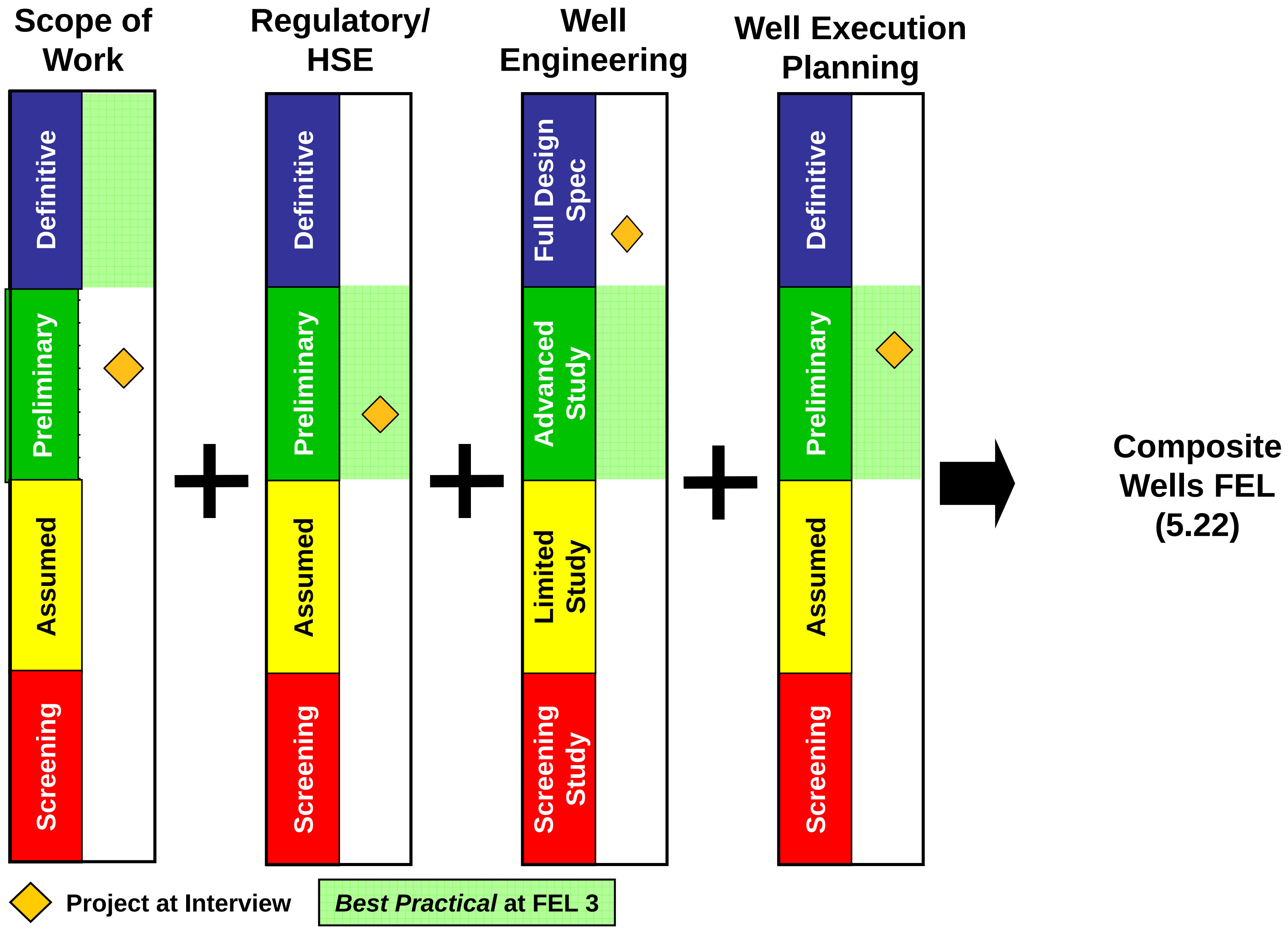
- Casing Design
- Completion and Stimulation Plans
- Certify Rig
- Certify Equipment
- Long-Lead Items Identification
- Scenario and Option Planning
- Peer Review
- Stakeholder Buy-in

Execution Planning

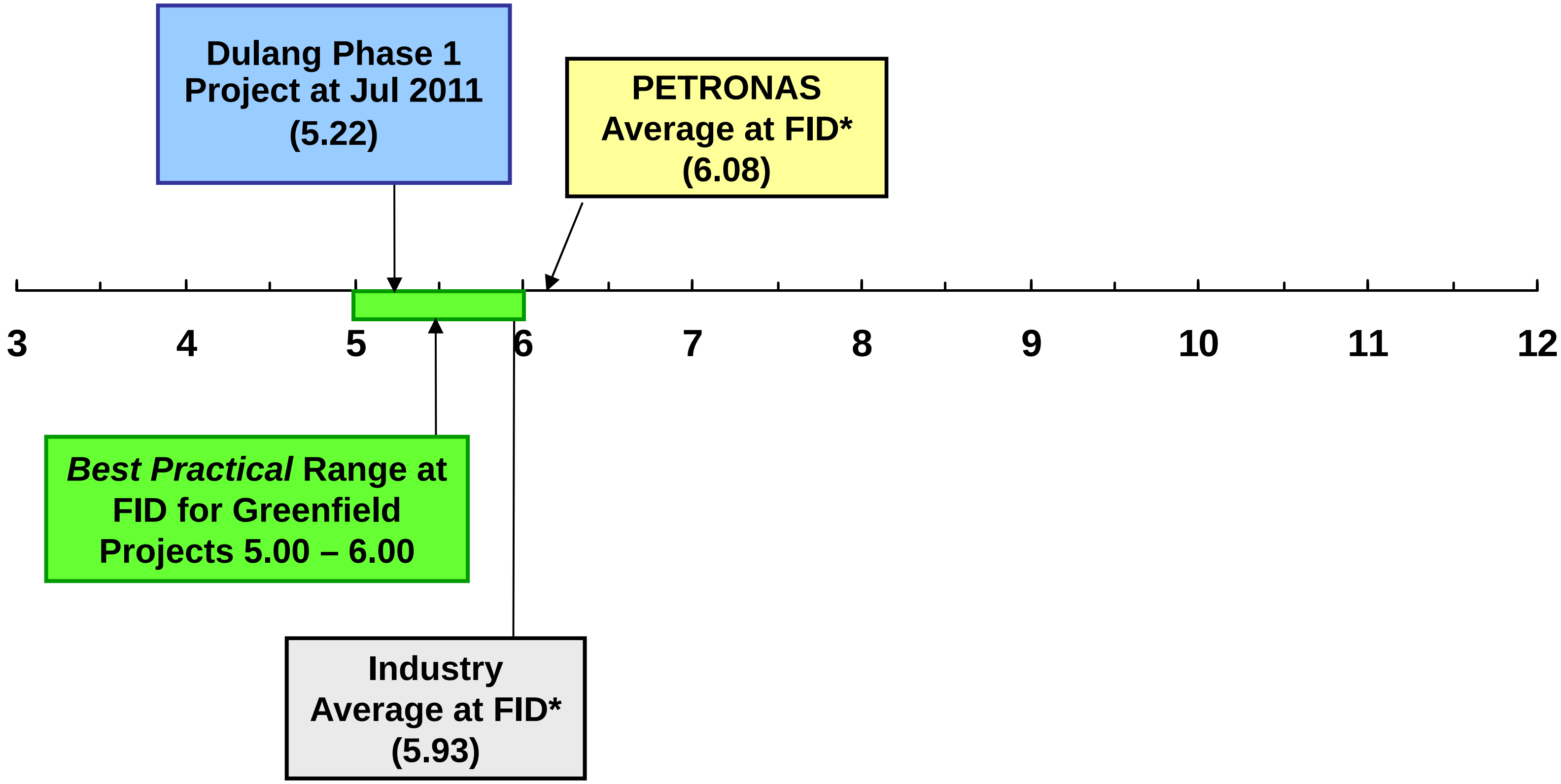
- Contracting Strategy
- Team Composition
- Procurement Plan
- Secured Rig
- Logistics
- Schedule Estimate Including Concurrent Ops, SIMOPs, etc.
- Detailed Well Plan to Achieve Objectives
- Program Cost Estimate

Wells FEL by Component

Best Practical for Phase 1 Sanction



Dulang Phase 1 Project Had *Best Practical* Wells FEL



* Upstream Industry Benchmarking Consortium - UIBC 2012

Scope of Work Was *Preliminary*

- **Lagged *Best Practical* rating of *Definitive***
- **Team understood environment in Dulang; location risks and uncertainties characterised**
- **Drilling program objectives developed; strategic fit with business plan defined**
  - **Consensus on overall program objectives and timing finalised with reservoir team after the approval process**
- **Well objectives defined for development and depletion plan**
- **Preparation of NOOP and integration of operations in the development plan not final at authorisation**

Regulatory/HSE Was *Preliminary*

- ***Best Practical*** **rating at authorisation**

- **Permit requirements for drilling activities identified at sanction and obtained closer to spudding date**

- **Potential drilling hazards identified at a program level, and DRC to review risk for each well performed prior to spud**

- **HSE management similar to other operations, as drilling activities were ongoing within PCSB**

Well Engineering Was *Full Design Spec*

- Exceeded *Best Practical* rating of *Advanced Study*
- Surface and bottomhole locations confirmed
- Preliminary drilling equipment list completed with specifications
- Team had well designs, mud, and casing programs for each well
  - Submitted to PMU however governance requirements do not call for PMU approval
  - Well designs were being optimised and revised based on reservoir updates

Execution Planning Was *Preliminary* (1)

- ***Best Practical*** **rating**
- **Core team in place, including completions engineer**
- **Overall well objectives locked down and understood by stakeholders**
- **Equipment list finalised; key vendors understood drilling program**
- **KM-1 rig selected under existing PCSB contract**
  - **Rig had been inspected**
  - **ERB West, PC4, and Angsi Early Monetisation Projects shared KM-1 rig under existing PCSB contract**

Execution Planning Was *Preliminary* (2)

- **Individual well AFEs prepared but governance process does not call for individual well AFE approval**
  - **Program AFE approved by PCSB with child AFE for each well used by PMT to track cost performance**
- **HAZOP and SIMOP reviews were preliminary**
  - **Preliminary HAZOP reviews in place; needed operations input for SIMOPs and SIPROD**
  - **Procedure for rig and platform integration finalised with operations and HSE**
  - **Cost tracking and progress monitoring through normal daily drilling report and AFE tracking process**

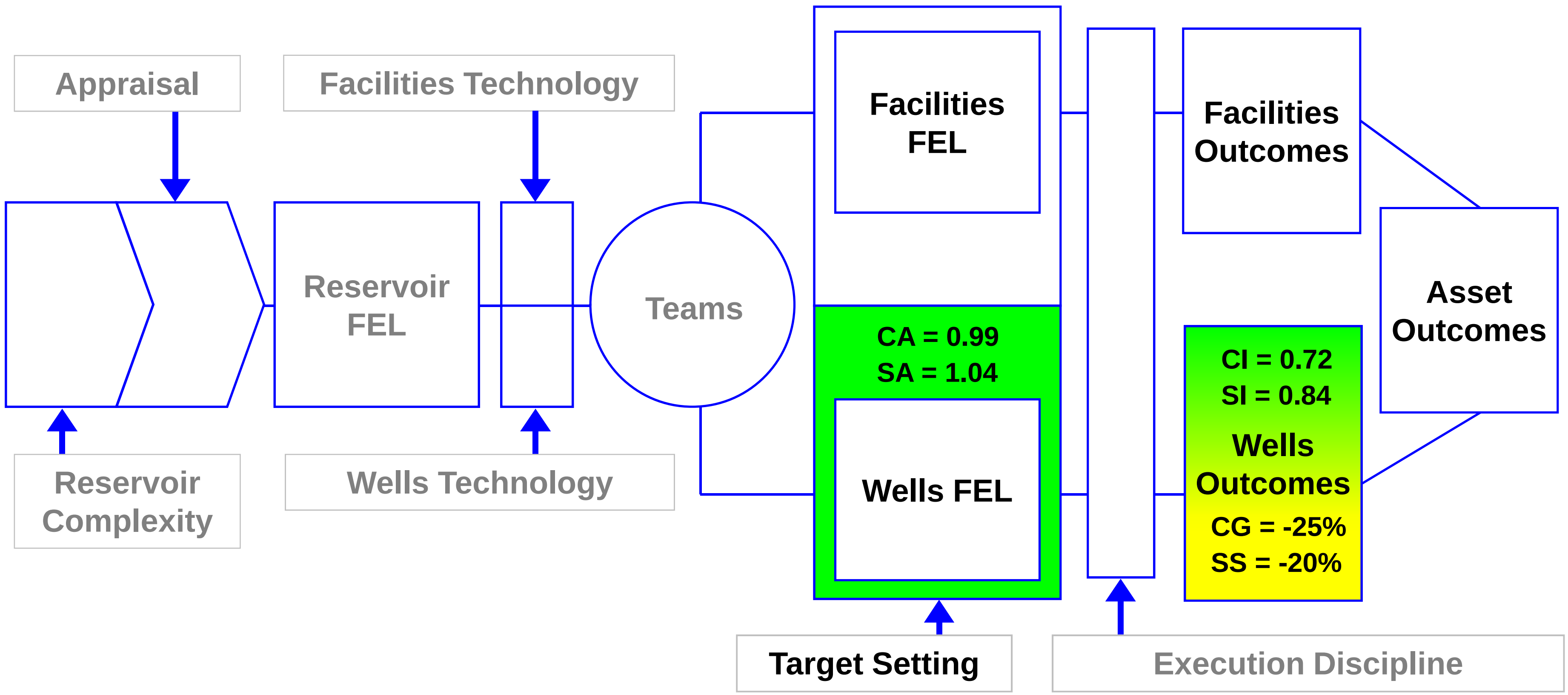
Summary of Project Drivers (FEL)

FEL Component	Dulang Phase 1	PETRONAS Average	Industry Average	Best Practical
Reservoir FEL	**5.46**	**6.07**	**5.90**	**4.00 - 5.00**
Inputs	Preliminary	Preliminary	Preliminary	Definitive
Constraints	Preliminary	Preliminary	Preliminary	Preliminary
Tasks	Preliminary	Preliminary	Preliminary	Definitive
Reservoir Execution Planning	Preliminary	Preliminary	Preliminary	Definitive
Wells FEL	**5.22**	**6.08**	**5.93**	**5.00 - 6.00**
Scope of Work	Preliminary	Preliminary	Preliminary	Definitive
Regulatory/HSE	Preliminary	Preliminary	Preliminary	Preliminary
Well Engineering	Full Design Spec	Advanced Study	Advanced Study	Advanced Study
Well Execution Planning	Preliminary	Preliminary	Preliminary	Preliminary

Outline

- Key Message and Pathway Summary
- Project Background, History, and Scope
- IPA Process and Methodology
- Basis of Comparison
- Practices and Drivers
- ***Outcomes***
- Conclusions and Lessons Learned

Dulang Phase 1 Project
Cost and Schedule Targets and Outcomes



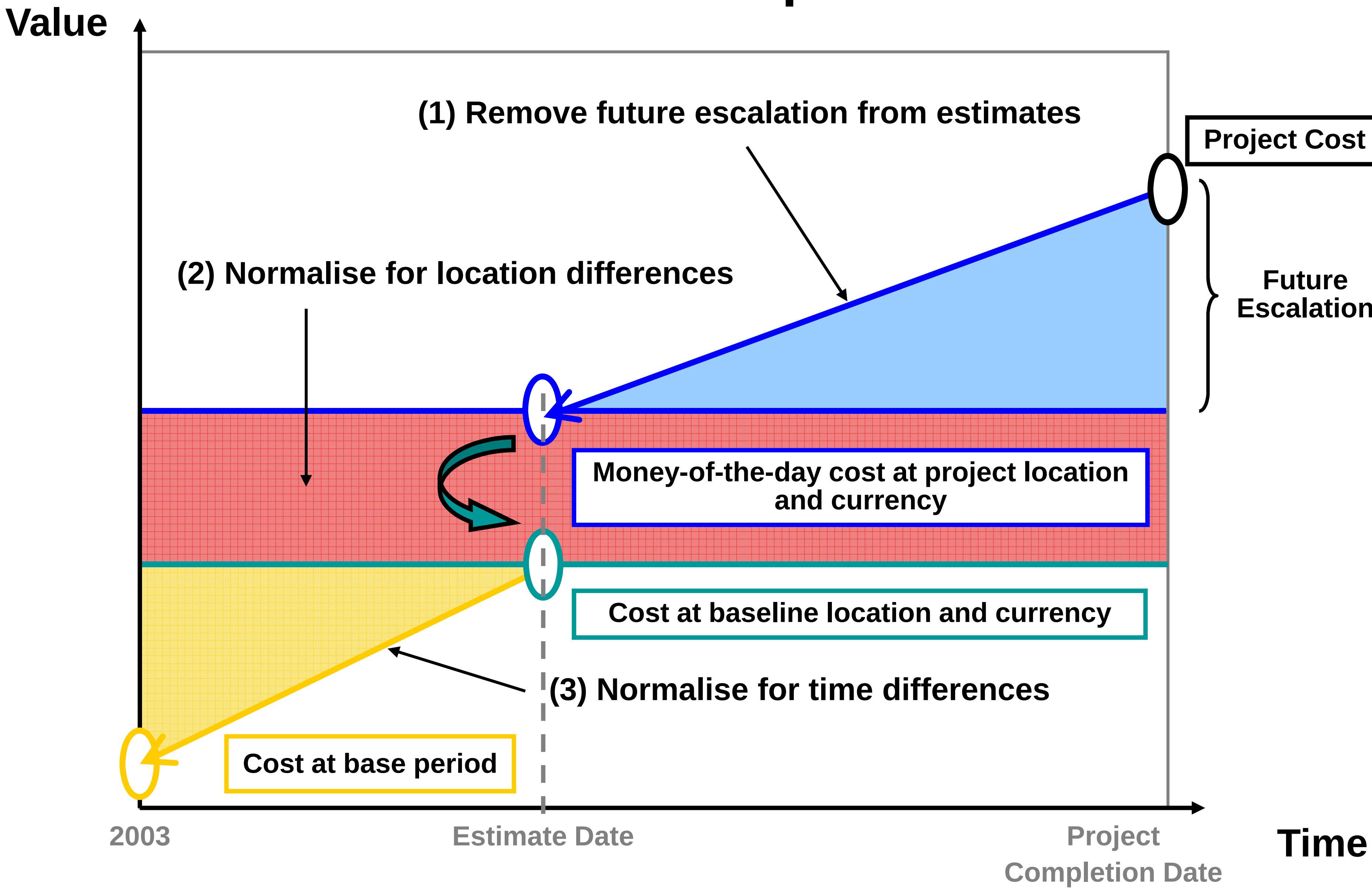
Risk	<<< Less	- - - - -	More >>>
Results	<<< Better	- - - - -	Worse >>>
	Low	Medium	High

CA – Cost Aggressiveness
CI – Cost Index
CG – Cost Growth
SA – Schedule Aggressiveness
SI – Schedule Index
SS – Schedule Slip

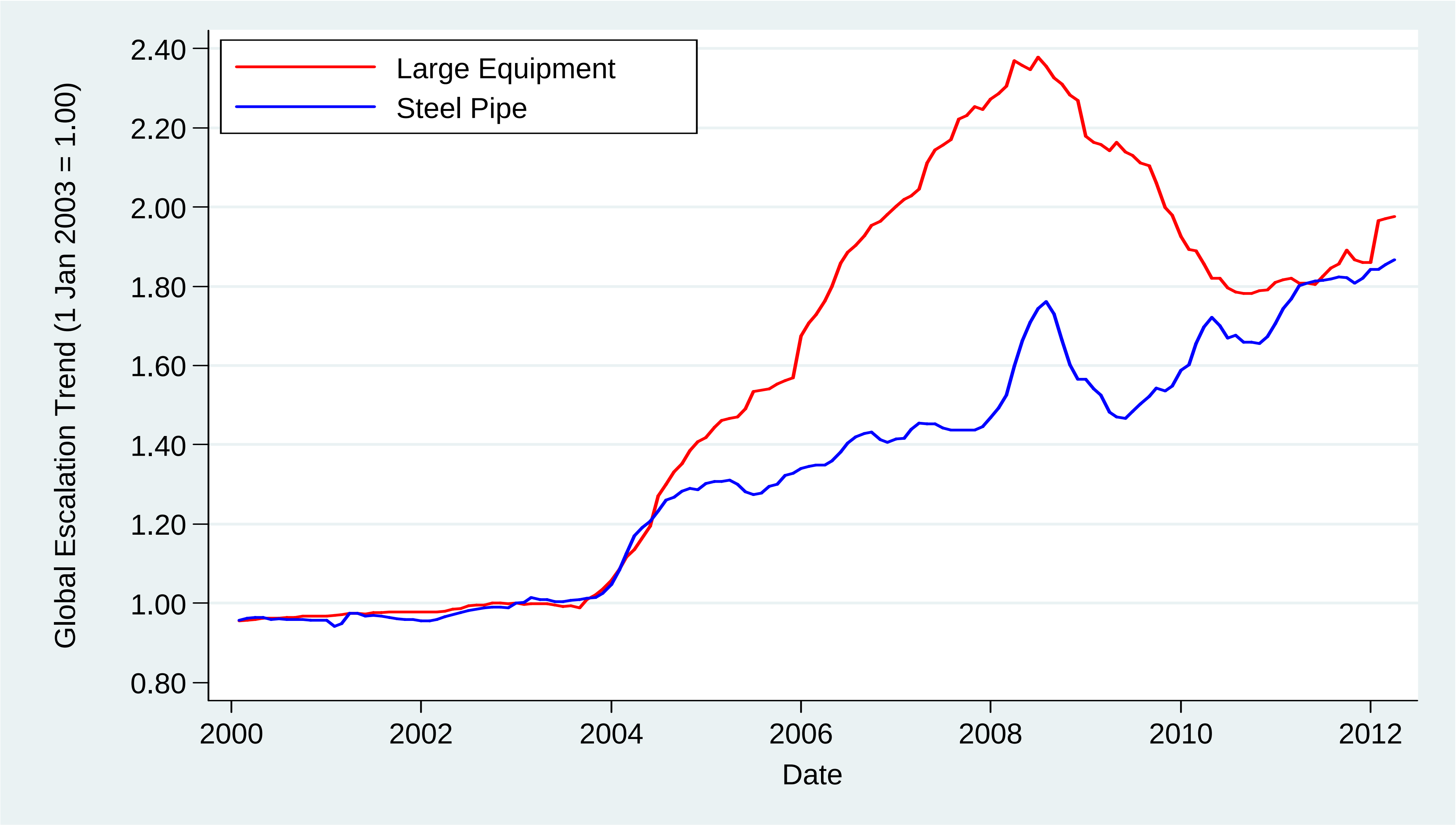
Cost Estimate Adjustment Methodology

- IPA adjusts line by line using provided cost breakdowns
  - Foreign exchange done using monthly average exchange rate to U.S. dollars
  - Costs de-escalated to constant date using previously discussed indices
- Estimates adjusted based on date of estimate
- IPA assumes:
  - Prices reflect estimate date
  - Escalation is broken out
  - Contingency is broken out
- When escalation is buried in line items, IPA adjustments and benchmarks are not as accurate

How Does IPA Normalise Costs? Three Steps

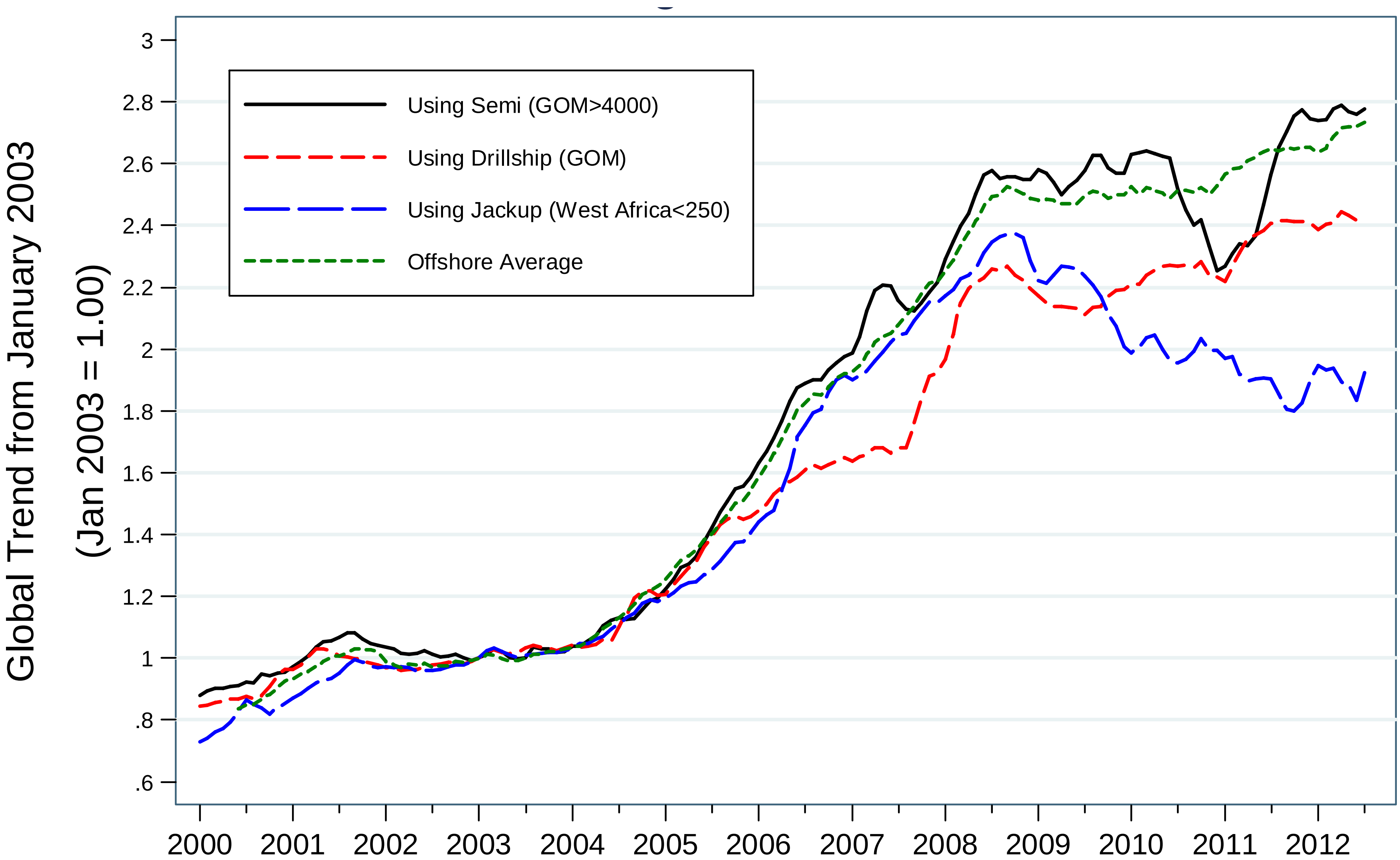


Upstream Material Cost Escalation



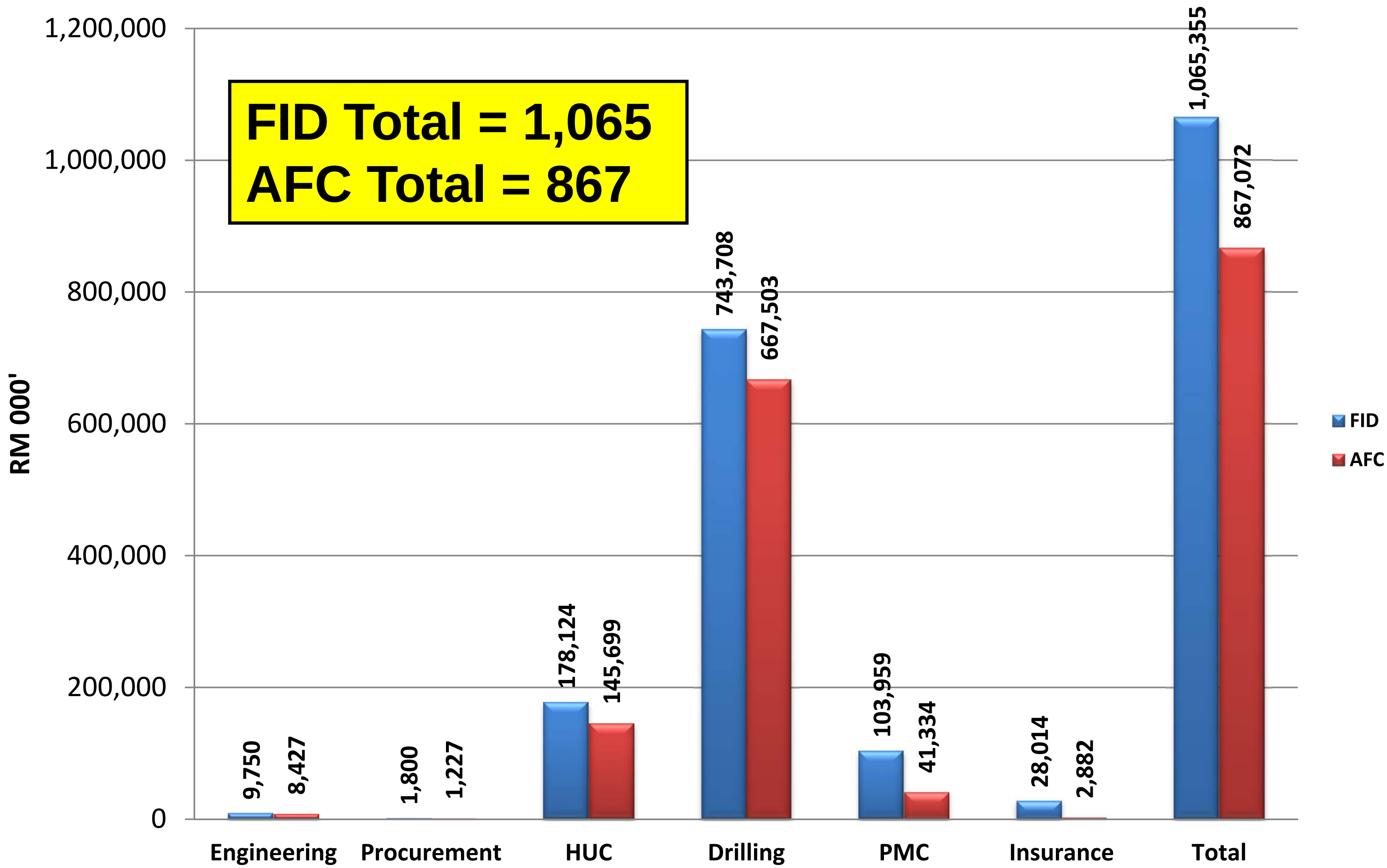
Equipment data primarily fabricated equipment (e.g., compressors, separators)
Cost escalation in US dollars

Wells Program Cost Escalation



Cost escalation trends are displayed in US dollars.

Dulang Phase 1 Project Cost Reconciliation (2)
PETRONAS Cost Reporting



Source: Dulang Redevelopment Project Phase 1 – IPA Closeout Report Briefing

Cost Breakdown Methodology (1)

- Costs prorated between HUC and wells
  - PMC
  - Detailed engineering
  - Insurance
  - FEL
- AFEs and end of well reports used to break down well construction costs into IPA categories
- AFEs and platform report cards used to break down HUC costs into IPA categories
- PETRONAS cost control report (31 October 2013) used to reconcile total project estimate and actual

Cost Breakdown Methodology (2)

- **FEL costs of RM55.8 million sourced from PETRONAS document *Dulang PH1 CCR Aug 2013.xls,* tab *Cum VOWD Input Sheet,* cell AD226**
  - **Value represents project costs incurred before sanction in July 2011**

Dulang Phase 1 Wells Benchmark Adjustment

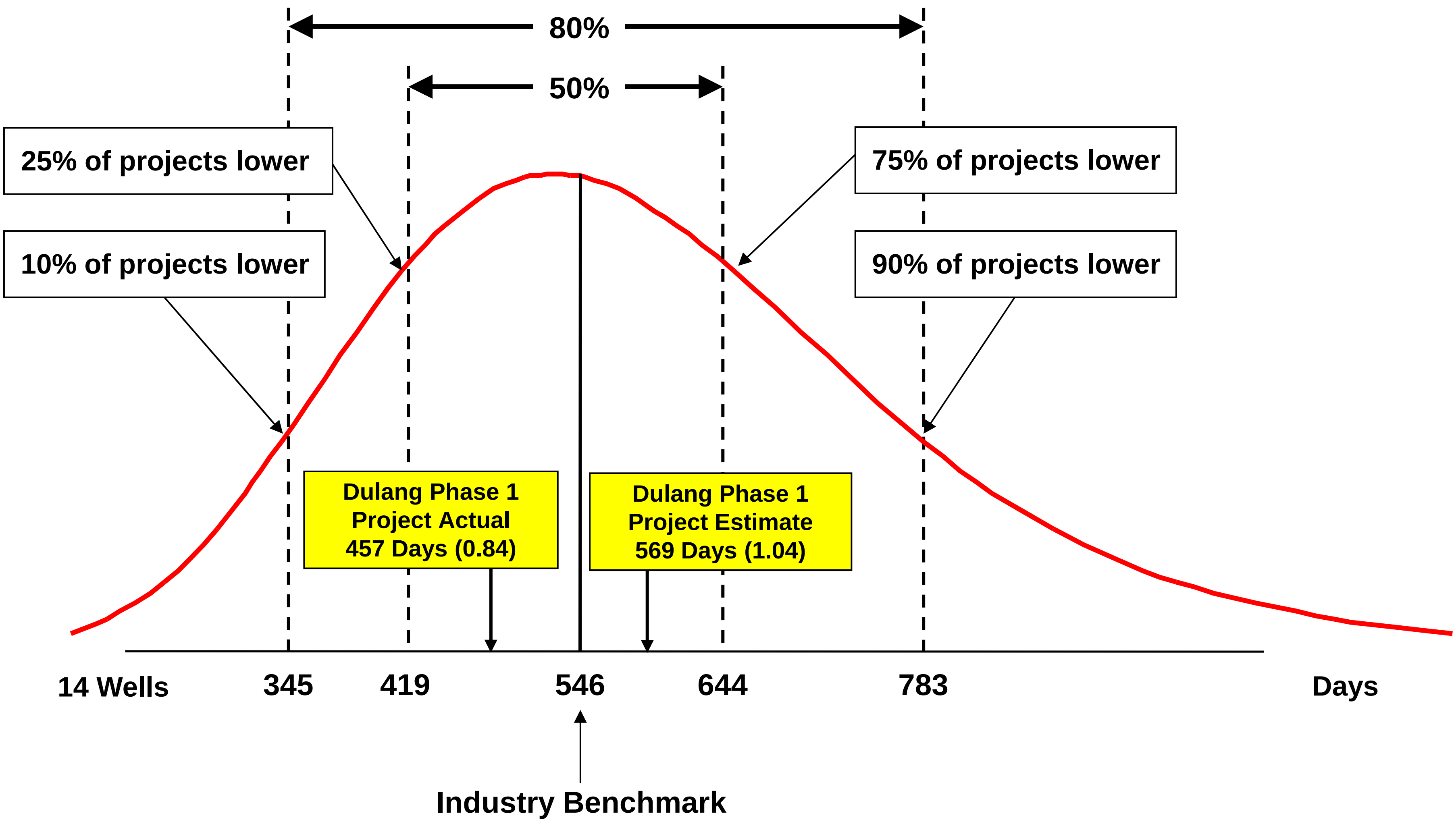
- **Duration and cost for workover activities on sidetrack wells is removed from Dulang Phase 1 estimate and actuals for benchmarking purposes as follows**

Item	Base Value	Adjustment	Benchmark Value
Duration Estimate (days)	638	69	569
Duration Actual (days)	493	36	457
Cost Estimate (RM MM)	903	98	805
Cost Actual (RM MM)	713	52	661

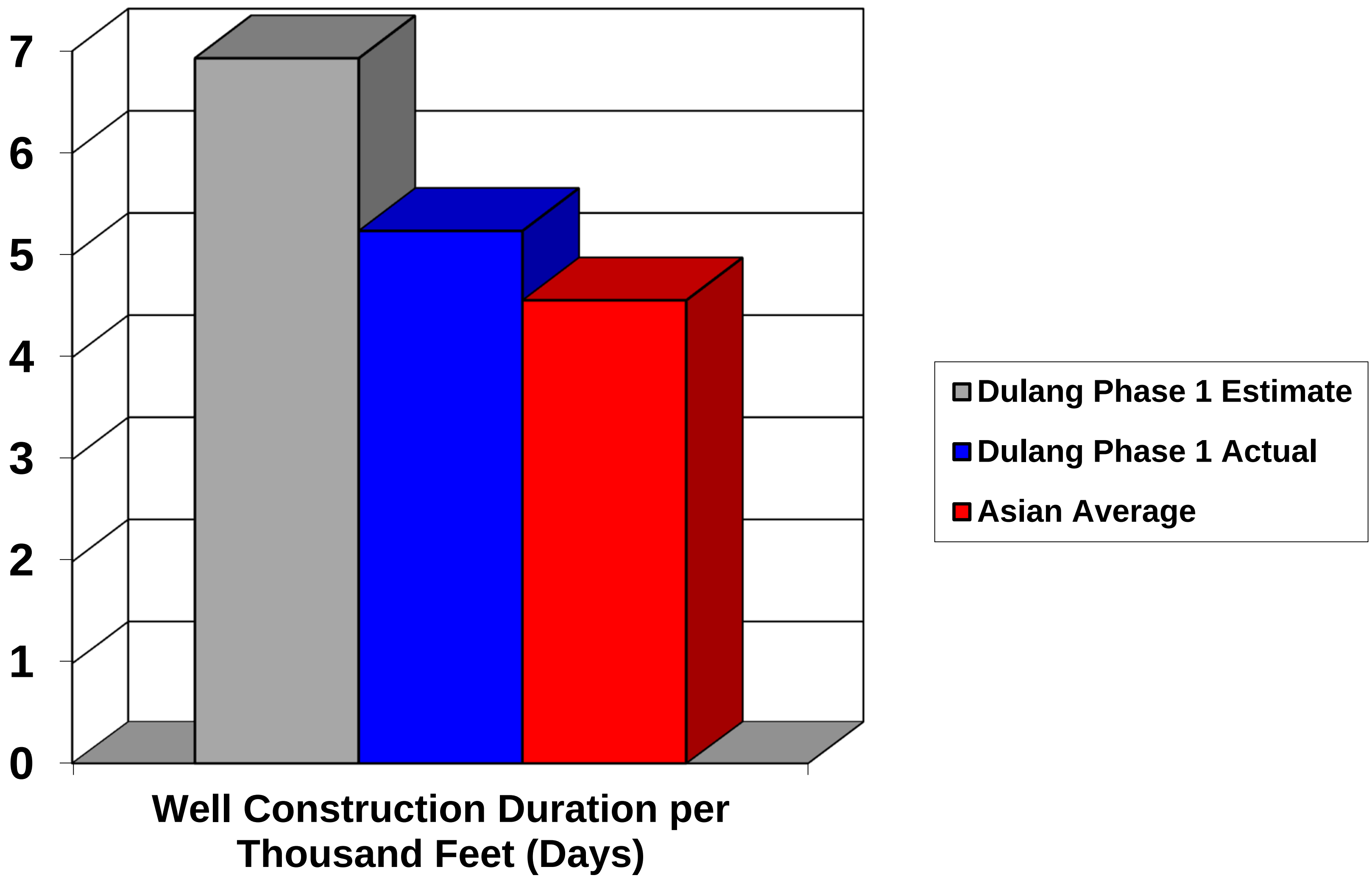
- **Cost adjustment is a function of duration and spread rate**

- Subject to benchmarking

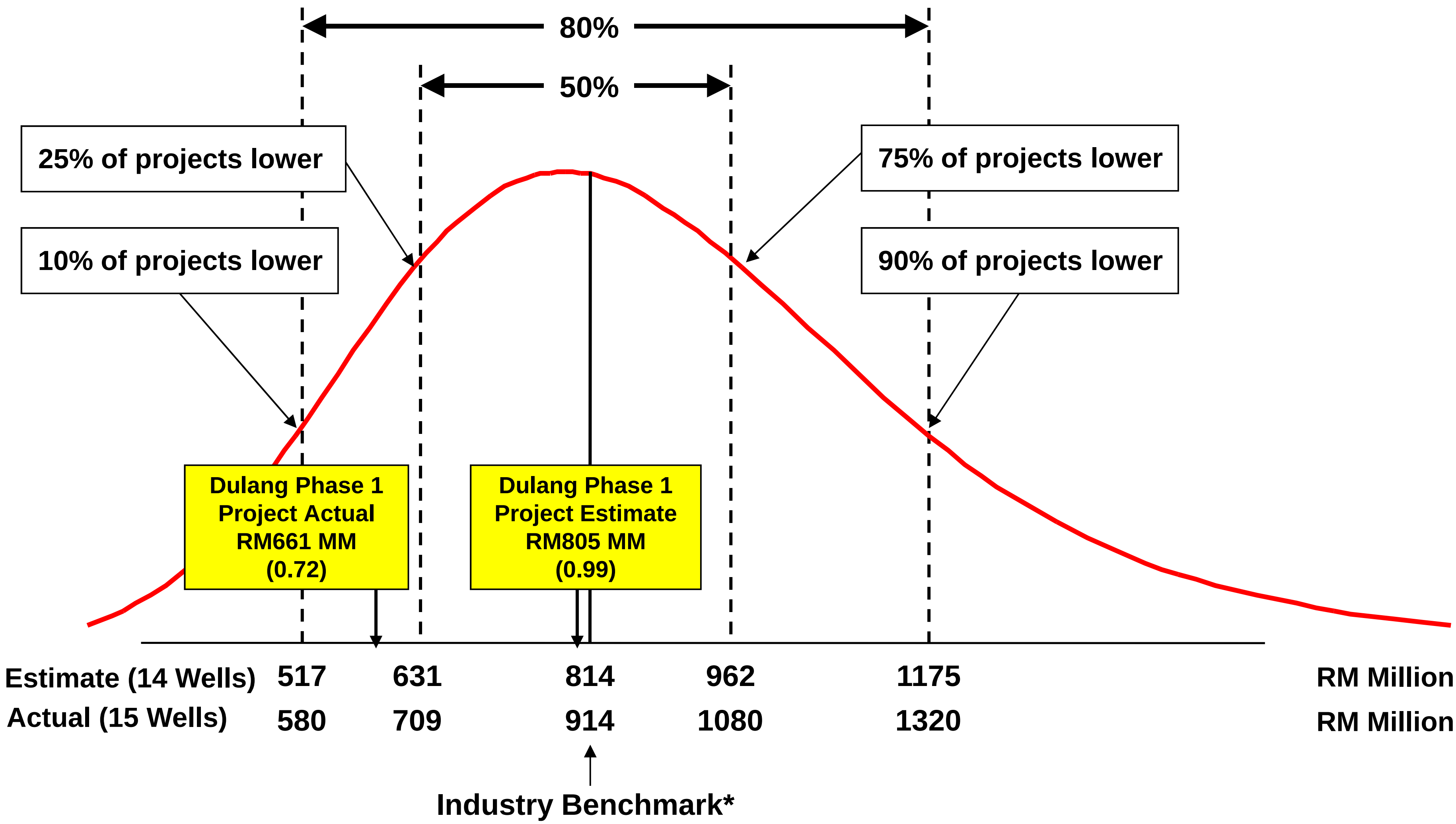
Dulang Phase 1 Project Wells Were Faster Than Industry



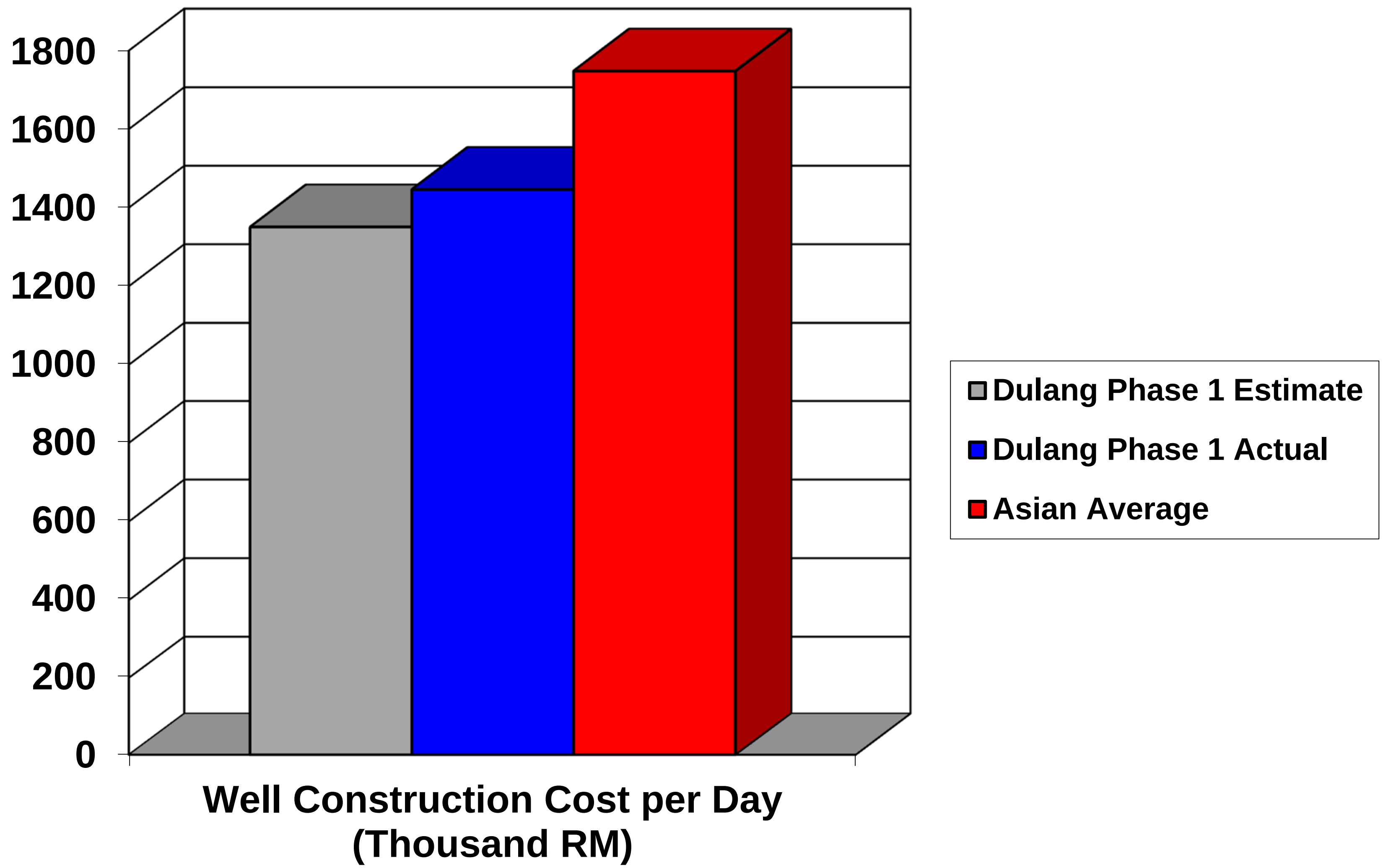
Project's Actual Days per Thousand Feet Was Faster Than Planned



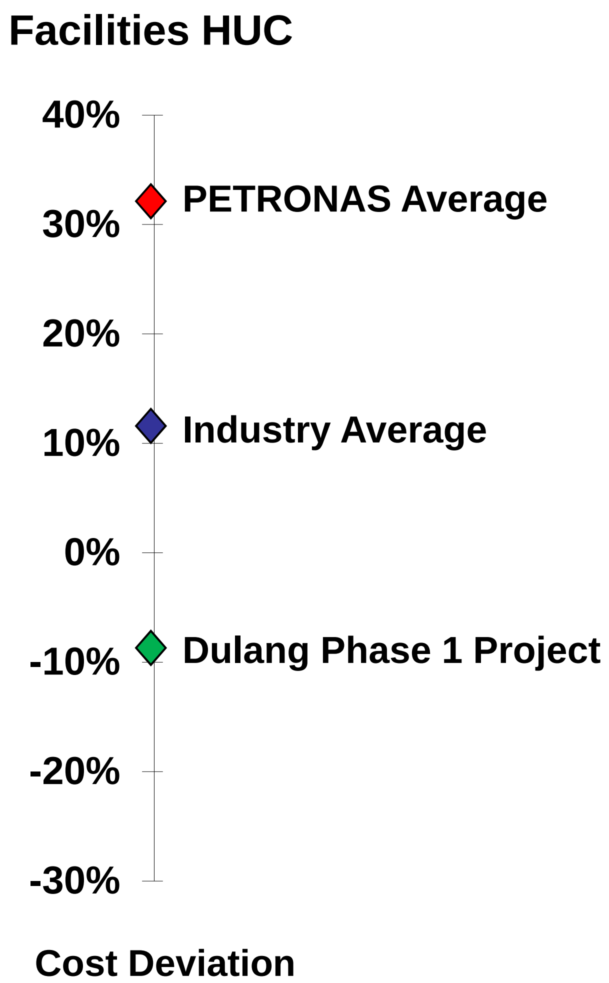
Dulang Phase 1 Wells Cost Is Competitive

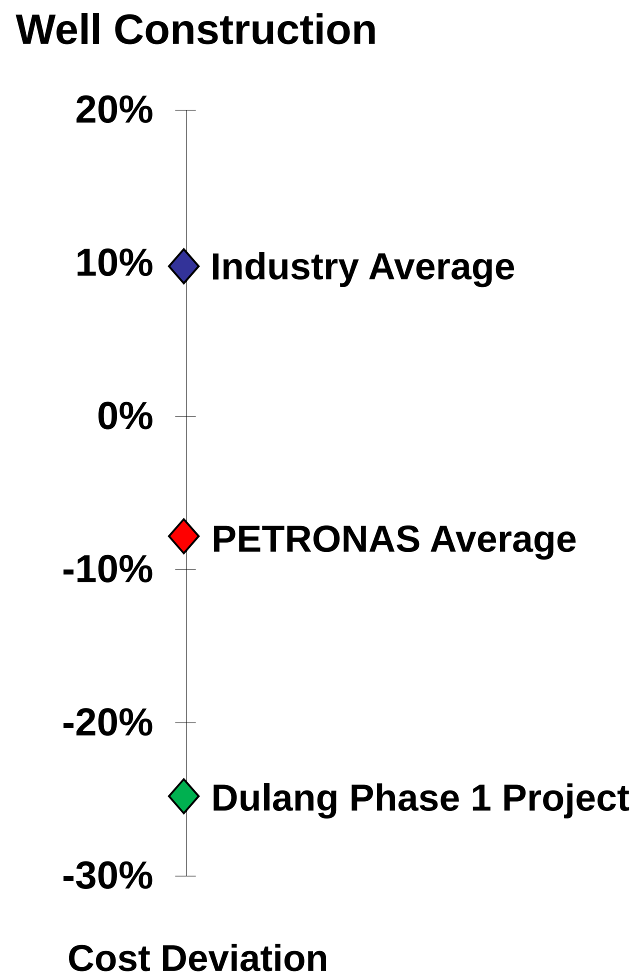


Project's Wells Cost per Day Was Less Than Asian Average



Dulang Phase 1 Project Underran Cost Which Resulted in Poor Predictability*





Negative cost growth is cost underrun
*Good predictability is +/- 10 percent

* Upstream Industry Benchmarking Consortium - UIBC 2012

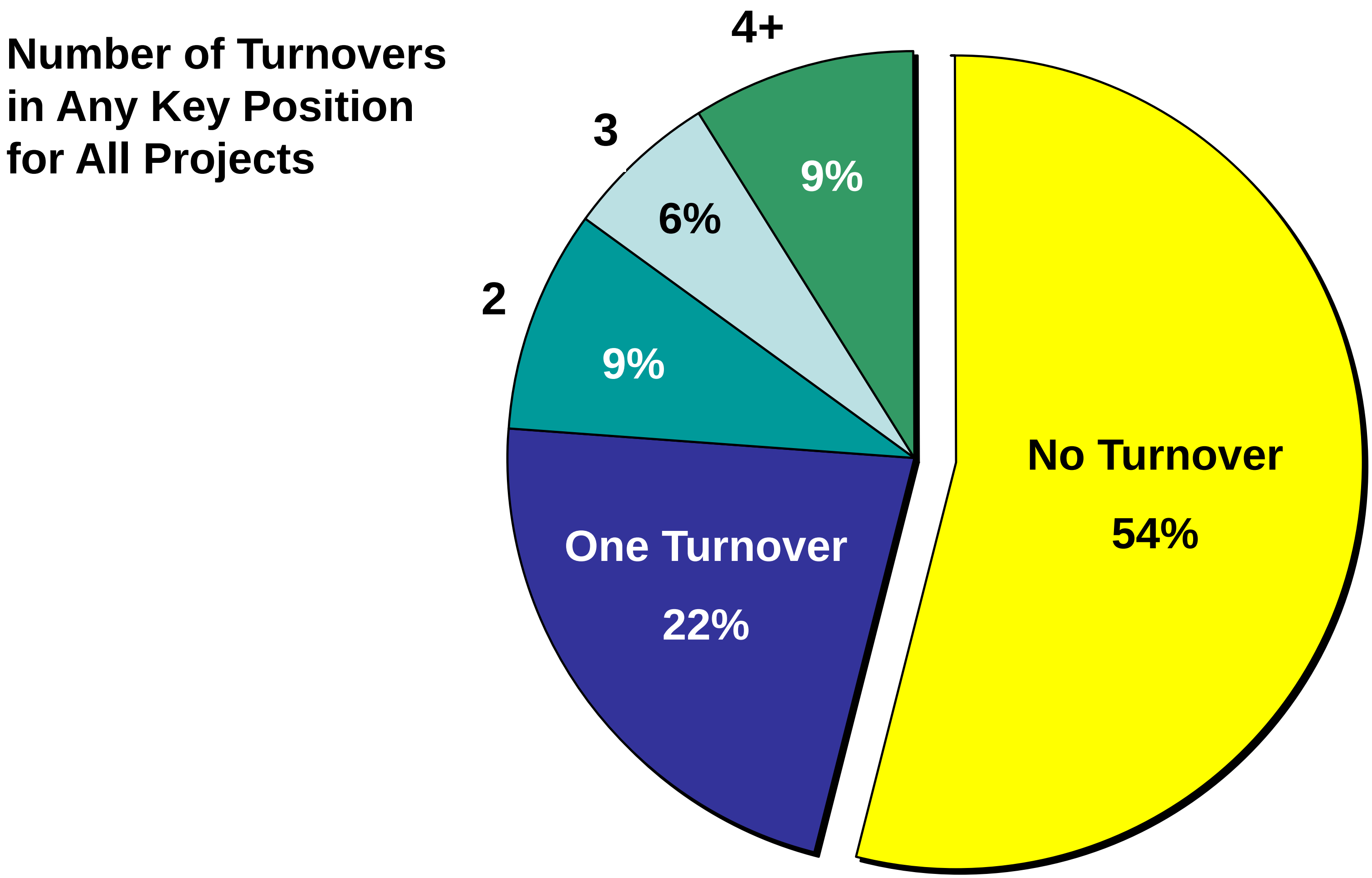
Dulang Phase 1 Analysis Summary

- **Wells cost estimate was in line with Industry average**
  - Low cost per day offsets high duration per thousand feet estimate
- **Wells estimated duration per thousand feet was higher than Asian average and decreased significantly**
  - Net wells performance was better than industry
- **Project authorised RM198 million that was not spent**
  - Over estimating ties up additional capital to a project that could be better used for other business
- **Well performance was proactively optimised during program, which also contributed to cost underrun**
  - Slim hole well design and hands on involvement with service providers to optimise each additional well contributed to good wells performance

Dulang Phase 1 Execution Discipline
High Team Member Turnover

- **Project experienced significant personnel turnover**
  - **Project manager turned over in August 2011 shortly after authorisation**
  - **General manager of business unit turned over in August 2011**
  - **Facilities lead turned over early 2012**
  - **Approximately 60 percent of the entire team turned over since sanction**
  - **Approximately 90 percent of the entire team turned over since the start of FEL 3**
  - **Most common reason for turnover is career progression and/or a person being moved into a more important project**
- **Team member turnover directly impacts project outcomes**

Historically, Nearly Half of Capital Projects Experience One or More Turnovers



Source: Julien Saillard and Swati Bhat, *Effects of Key Team Member Turnover,* IPA, 2005

Key Team Member Turnover Affects Cost, Schedule, and Operability but Impact Can Be Mitigated

	Deltas for Any Turnover After Correcting for FEL Pr < 0.05
Cost Index	**+3%**
Cost growth	**+2%**
Cycle time	**+14%**
Execution schedule Index	**+7%**
Execution schedule slip	**+5%**
Early operability	**-6%**

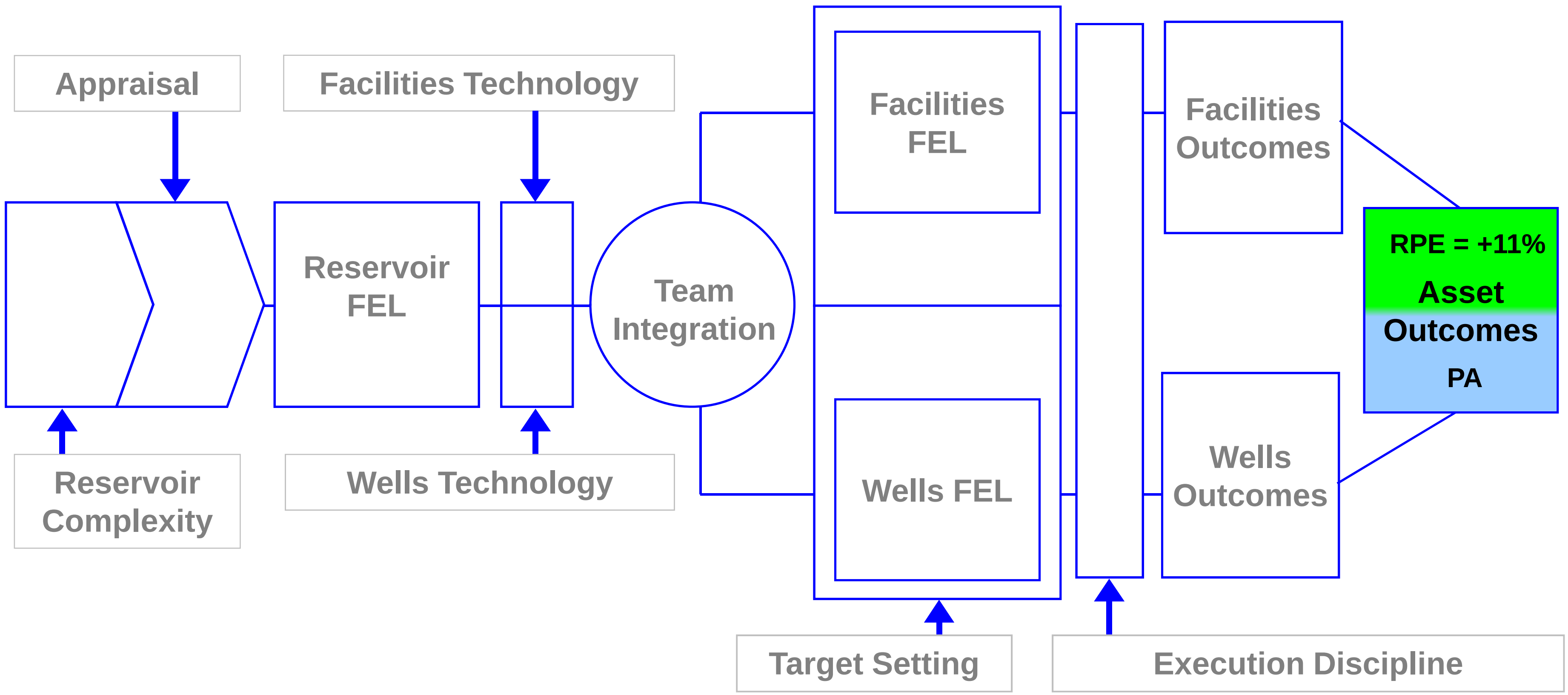
Source: Julien Saillard and Swati Bhat, *Effects of Key Team Member Turnover,* IPA, 2005

Tips To Manage Turnover: Planning for the Transition Blunts the Impact of Turnover

- **The following have been found by IPA as *Best Practices:***
- **Arrange for overlap with or continued availability of the person who is leaving**
  - **Progressively transfer knowledge of project**
  - **Inform replacement of decisions made**
  - **Hand over documents and e-mails**
  - **Maintain relationships**
- **Agree that replacement will not challenge previously made decisions unless safety, operability, or maintainability is really at stake**
- **Evaluate effect on other team members' workload**
- **Assess potential impact on project progress**

Source: Julien Saillard and Swati Bhat, *Effects of Key Team Member Turnover,* IPA, 2005

Dulang Phase 1 Project Asset Outcomes



Risk	<<< Less	- - - - -	More >>>
Results	<<< Better	- - - - -	Worse >>>
	Low	Medium	High

RPE: Resource Promise Estimate
PA: Production Attainment

Dulang Phase 1 Project RPE (mmbbls) in Line With Expectations

	Estimated Jul 2011	Updated Oct 2013	RPE Change
Resource Promise Estimate (To End PSC*)	25	27.7**	11%
Resource Promise Estimate (Field Life)	37.6	35.5**	-6%

- **Resource promise estimates close to sanction targets for both end of PSC and full field life**

*** PSC expires 2021** **** As per update from PETRONAS in Oct 2013**

Dulang Phase 1 Production Observations (1)

- **Planned peak production of 9 kbbl/day**
- **Current proved technical potential at September 2013 is approximately 9.3 kbbl/day**
  - **6 zones yet to be opened which expects to add 4.9 kbbl/day of technical potential**
- **But actual production increase is very difficult to measure and will be further quantified over time**
  - **Stabalisation and other topside constraints mean full technical potential is yet to be realised**
  - **In addition, other competing workover projects have also increased Dulang asset production**
    - **Differentiating between the source of production is very difficult, if not impossible, given the current metering**

Dulang Phase 1 Production Observations (2)

- **A detailed understanding of production performance is important given this is an EOR project with the primary objective of increasing production**
  - **Clearly defined objectives and KPIs may have started the discussion around how production was planned to be measured, and how this related to Phase 2**
- **PETRONAS has used initial Phase 1 production results along with WAG pilot to assess the viability of Phase 2; and as such have delayed Phase 2 authorisation to further define performance**

Outline

- **Summary**
- **Project Background**
- **IPA Process and Methodology**
- **Basis of Comparison**
- **Practices and Drivers**
- **Outcomes**
- ***Conclusions and Lessons Learned***

Conclusions

- **Dulang Phase 1 Redevelopment Project had competitive cost and schedule**
  - **22 percent underrun of wells and HUC costs led to competitive but unpredictable outcomes (escalation adjusted)**
- **Asset outcomes are in line with expectations at authorisation**
- **Technical production potential exceeds authorisation promise via offline separator testing; however:**
  - **Overall production is system constrained and further work is required to understand production performance**
  - **EOR production performance measurement is a long term and difficult process requiring annual data plans**

Lesson Learned: Recognise the Importance of Basic Data Plans for Phased Developments

- Dulang Phase 1 has been used in part as a data gathering exercise to underpin the development of Dulang Phase 2, a much larger EOR development
- Phase 1 production performance is critical to determine Phase 2 potential value
  - Some early system production performance uncertainty exists around Phase 1 which is common for EOR projects
- Data requirements should be established early during a phased development and be linked to project objectives, plans and later phase uncertainty
- The Dulang Phased development approach for data acquisition in an uncertain environment should be recognised as a good practice for future projects

Lesson Learned: Recognise the Importance of Consistency of Key Personnel

- Key project positions should be identified during the early planning stages and resource planning done to match the project's need
  - Key team member turnover should be avoided if possible
- If turnover must occur:
  - Arrange for overlap with or continued availability of the person who is leaving
  - Agree that replacement will not challenge previously made decisions unless safety, operability, or maintainability is really at stake
  - Evaluate effect on other team members' workload
  - Assess potential impact on project progress

Lesson Learned: Communicate Learnings From Good Drilling Performance to Wider Audience

- Document learnings from good wells cost and schedule results and share them with a wider PETRONAS audience to ensure knowledge transfer
- Include technical and management practices that can benefit other PETRONAS well programs, such as:
  - Slim hole well design
  - Hands on involvement with service providers to optimise each additional well
- PETRONAS has performed the above knowledge sharing which is a good practice for improving project systems

Lesson Learned: Recognise That Project Predictability is Important to a Project System

- Dulang Phase 1 Project achieved competitive wells outcomes however predictability was poor
- Cost and schedule predictability is important for a project system as it allows business to appropriately allocate resources and capital
- A lack of predictability creates a project system that is unstable and difficult to manage at a portfolio level
- Cost competitiveness for Dulang Phase 1 should be congratulated; however predictability – albeit a cost reduction – should be viewed as an area for improvement

IPA

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