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Increasing Economic Value for Offshore Marginal Field Development Through an Optimization Production Development Strategy

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INCREASING ECONOMIC VALUE FOR OFFSHORE MARGINAL FIELD DEVELOPMENT THROUGH AN OPTIMIZATION PRODUCTION DEVELOPMENT STRATEGY - A CASE STUDY : "X" FIELD DEVELOPMENT OF OFFSHORE NORTH WEST JAVA INDONESIA

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Abstract

The main challenge in developing marginal field is the geographical conditions of the region, which consisted of a scattered platform and contained a small amount of resource. Conceptual phase studies for new "X" Field development have been performed, but shown pessimistic outcomes. Economic indicators show that New X field development has an Internal Rate of Return (IRR) of 9.4% and Net Present Value (NPV) of negative $ -1.2 M. Synergistic development strategy between Subsurface and Surface facilities needs to be applied to increase the economic value of the project. This paper will present the development plan of X green field development that will cover comprehensive analysis of subsurface, surface facility designs and economic aspects of field development. The idea is to optimize the production strategy in order to obtain bigger resources in same structure. Considering reservoir condition and fluid characteristic, there are three types of artificial lift used in reservoir simulation: Gas Lift from Compressor, In Situ Gas Lift and the use of Electric Submersible Pump (ESP). Each of these artificial lift options will be exercised completed with several impacts on the surface facility design. The use of flexible pipeline as the new technology is covered in this study to optimize CAPEX of the facility. Project economic is then run after calculating the cost estimation of each option. In the end, the In Situ Gas Lift option is selected as the best option which will increase resource to 3.16 MMBO (from 2 MMBO originally), reduce the total CAPEX for field development about $ 1.8 M , achieve positive NPV about $ 13.5 M, increase IRR to 28% and speed up the payback period of three years.

Keywords: Optimization, Marginal Field, Artificial Lift, Project Economics

1. Introduction

The X structure is located about 19 km from B flowstation with the structure discovery of A-1 exploration well in 1997. The potential for oil and gas reservoirs are in the Main Sandstones formation, with the DST test results from 2 reservoirs totaling 1130 BOPD and 8 MMSCFD. The status of this structure has never been produced with estimated oil reserves (P50) are 7.2 MMBO and gas of 3.7 BCF. The estimated initial production flow rate (P50) of oil is estimated at 2000 BOPD and gas of 1 MMSCFD.

The initial plan for field development in X's structure was drilling 3 (three) wells with 3 single selective wells on the X platform, namely: X-1, X-2, and X-3. The wells will naturally flow to "B" Flowstation as the nearest Flowstation in this area.

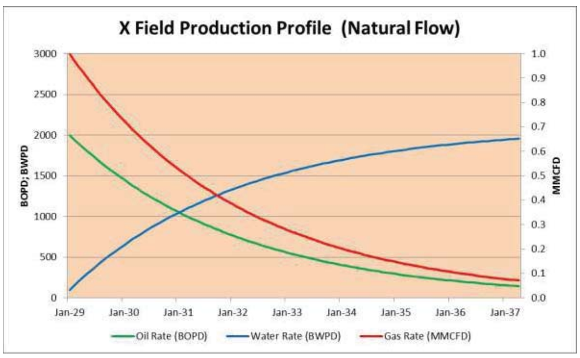

Fig 1. X Field Production Profile Natural Flow

However, world oil prices which have fallen sharply in recent years and the concept of technology currently used contributed to high facility costs. This situation gave a low project economics because it would not be comparable with the reserves to be developed. For this reason, value added innovation is needed so that the development of the old and marginal field of the ONWJ block meets the limits of economic value to be developed.

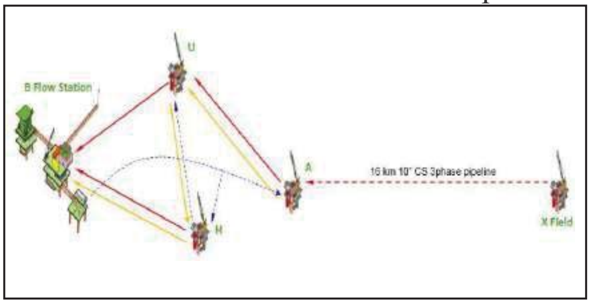

Fig 2. X Field Initial Development scenario

2. Basic Theory

2.1 ESP and Gas Lift Injection

Deciding artificial lift is a process to choose which lift method is the most applicable to the expected surface, reservoir, fluid and operational conditions. Lift process can either transfers energy downhole or decreases fluid density in the wellbore to reduce hydrostatic pressure on formations. There are many types of artificial lift but the two common practices for offshore application are Electrical Submersible Pump (ESP) and Gas Lift.

ESP will create heads that usually called total dynamic head (TDH) which consist of net vertical lift, friction and wellhead pressure. Net vertical lift is the vertical distance through which the fluid must be lifted to get to the surface. Friction is the energy loss due to viscous shear of the flowing fluid. Wellhead pressure is sometimes called surface pressure or back pressure as the resistance at the surface that the pump must overcome.

$$\mathrm{TDH} = Net\ Vertical\ Lift + \Delta P\ Friction + Feet\ Wellhead$$

$$\Delta P\ Friction = \frac{f \rho v^2}{2 g_c d}$$

$$Feet\ Wellhead = \frac{Wellhead\ Pressure}{0.433\ x\ SG}$$

Gas lift will reduce fluid gradient to lower flowing bottom hole pressure. Injection gas rate can be calculated with following equation

$$Q = \frac{155.5 C_d A P_u \sqrt{2gk\left(R^{2/k} - R^{(k+1)/k}\right)}}{\sqrt{\gamma_g T}}$$

While injection gas rate at a certain depth can be calculated as

$$q_{gi} = \frac{q_{g,sc}(T_v + 460)}{520}$$

2.2 Pipeline Sizing

High velocities in two-phase lines can cause rapid wear by erosion. The velocity at which erosion may occur is calculated by the formula given in API RP14:

$$\mathbf{Ve} = \frac{\mathbf{C}}{\sqrt{\boldsymbol{\rho_m}}}$$

Ve = erosional velocity (m/s)

Empirical constant used C = constant (ft/s)

= 100 for CS lines in continuous services

= 125 for CS lines in intermittent services

Density of the gas/liquid mixture (ρ_m) can be estimated by the following:

$\rho_m = \rho_g (1 - \lambda) + \lambda \rho_l$, where :

λ : liquid volume fraction

ρ_g : gas density (kg/m^3)

ρ_l : liquid density (kg/m^3)

2.3 Project Economics

..(1)

NPV is the difference between expenditure and income that gets a discounted price by using the social opportunity cost of capital as

..(2)

a discount factor. NPV itself is a net profit based on the amount of Present Value (PV). To calculate NPV, you can use the formula below:

$$NPV = -C_0 + \sum_{i=1}^{T} \frac{C_i}{(1+r)^i}$$

To get the final result of the IRR calculation, we have to find a discount rate that produces a positive NPV. You can see the IRR formula below:

$$IRR = i_1 + \frac{NPV_1}{(NPV_1 - NPV_2)}(i_2 - i_1)$$

Internal rate of return (IRR) is the discount rate at which the net present value of an investment becomes zero. In other words, IRR is the discount rate which equates the present value of the future cash flows of an investment with the initial investment.

3. Methodology

A synergistic development strategy between Subsurface and Surface facilities have been applied in the conceptual design stage for developing marginal field in order to optimized the cost, speed up execution time and solutions for early backup monetization. The followings are alternate solutions to increase project economics:

3.1 Subsurface Optimization

Subsurface has performed optimization by the changing of production strategy in a reservoir which will have an impact to the design of the surface facilities. Deciding the number of production wells will give impact in producing large amount of oil and associated gas from that reservoir. The more the numbers of production wells, the more oil will be produced. However, the more production wells cause the more drilling process to be carried out, which inevitably results in greater production costs. Thus, it is clear that an optimization effort is needed in the oil production strategy so that the optimal amount of oil / gas and the number of drilling wells are obtained. Optimization is also carried out on the type of artificial lift used both with gas lift injection and in usingElectrical Submersible Pump (ESP). Those will give significant impact to surface facility design.

3.2 Surface Facility Optimization

Surface facility design can be optimized by applying advance technology on the topside facility and the use of flexible pipe as alternative against carbon steel pipeline. Flexible pipe is a pipe technology that uses Reinforced Thermoplastic Pipe which has more resistance to corrosion than carbon steel pipes and the installation of flexible pipes is easier and faster so that the installation costs will be lower than carbon steel pipes.

Table 1. Material Pipeline Comparison

Deskripsi	Carbon Steel	Flexible Non Carcass	RTP
Minimum Diameter	No Limitation	8”	6”
Maximum Pressure	No Limitation	15.5 Mpa	15.5 Mpa
Max. Water depth	No Limitation	62 m	30 m
Stability	*Concrete Weight Coating*	*Concrete matress*	*Concrete block*
Free Span Correction	Mandatory jika terjadi span melebihi allowable span	No need	No need
Installation Vessel	*Lay barge (S-lay conventional)*	*Reel lay by DSV*	*Reel lay by DSV*

4. Case Study

Based on the Hydraulic Simulation, Pipeline route from the X to A platform along 16 km is the most optimal by using a 10 inch pipe size since the A platform is the nearest existing facility.

As explained in the previous chapter, the initial plan for the development of the X oil field is drilling of three wells where the wellfluid is naturally flown and transported via 16 km pipeline to A platform. From the conceptual development design, the Surface facility design covers the installation of a Braced Monopod conventional structure platform completed with topside facility and 10” production pipeline from X to A platform along 16 km. With this design, Surface facility cost is estimated around US$ 36.8 M. With a small reserved and high Capex, economic indicators show that New X field development has only an Internal Rate of Return (IRR) of 9.4% and Net Present Value (NPV) of negative $ -1.2 M. For this reason, value added innovation is needed so that the development of marginal field in the PHE ONWJ block meets the limits of economic value. Optimization efforts in the production strategy carried out are:

4.1 Gas Lift from Compressor

Similar with natural flow option, this option is driven by drilling three wells, X1, X2 and X3 Wells. With this artificial lift option, recoverable reserve will be increased to 4 MMBO and 2 BCF compared with natural flow case. However, this option requires 1.5 MMScfd of gas from Existing Compressor and additional installation of 6” lift gas pipeline along 16 km from the A to X platform. Conceptual design is attached in Appendix-B and Production Profile is as follows:

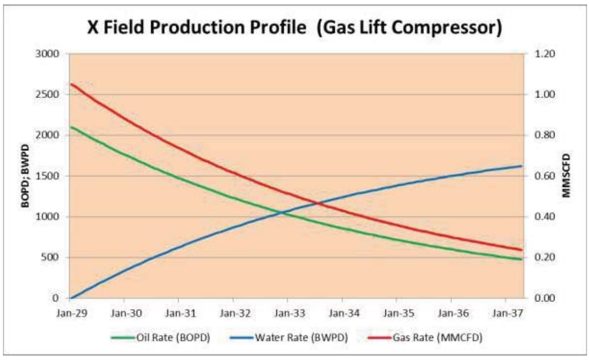

Fig 3. X Field Production Profile (GL Compressor)

4.2 In Situ Gas Lift

This option will install two single selective wells (X1 and X3) and one double selective well (X2L/S) where X2S well will provide in situ gas lift to the other wells. This option is chosen to eliminate the 6” gas lift pipeline costs from A to X by utilizing gas sources in X's own reservoir. The scope of work for this option are: Installation of Production pipelines using 10 "Carbon Steel along 16 km from the X to A Platform and the installation of new X platforms completed with topside facility. With this artificial lift, recoverable reserve will be increased to 3.12 MMBO and 1.68 BCF. Conceptual development scenario is attached in Appendix-C, Production Profile is as follows:

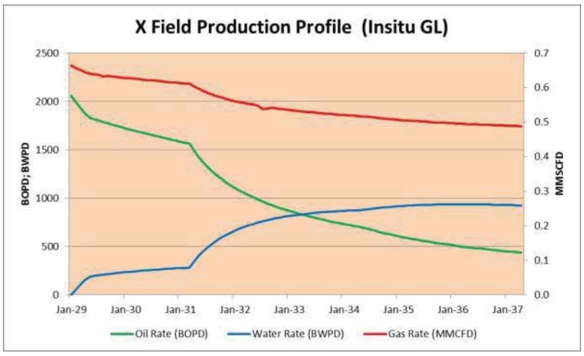

Fig 4. X Field Production Profile (In Situ Gas Lift)

4.3 Electric Submersible Pump (ESP)

This option is by planning to install two ESP Wells. This option is chosen to reduce pipeline size which gives significantly impact to the pipeline cost of 16 km long pipeline from X to A platform. By using ESP, the production strategy expects that large amount oil is released as much as possible in the first production and the new gas zone is opened at the end of production. This strategy will impact the use of smaller production pipeline size to 6 inches. However, with the installation of ESP on the X platform, a power generation is needed which is obtained from the B Flowstation via a 19 km submarine cable. The scope of work for this option-2 is: Installation of 6” Production pipeline using "Flexible Pipeline about 16 km from X to A platform, installation of new platforms completed with topside facility (X Platform) and Subsea cable installation along 19 km for ESP from B Flowstation to the X platform. With this artificial lift, recoverable reserve will be increase to 3.75 MMBO and 1.88

BCF. Conceptual development scenario is attached in Appendix-D, Production Profile is as follows:

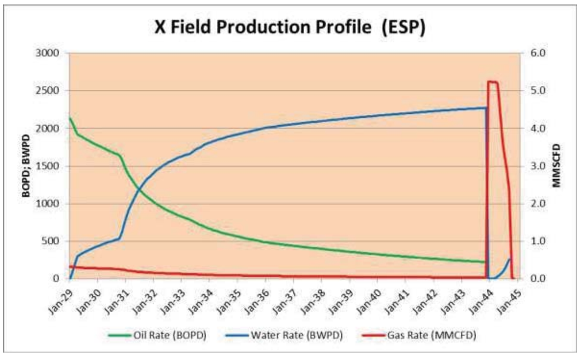

Fig 5. X Field Production Profile (ESP)

5. Result and Discussion

Detailled study result is attached in Appendix A (Comparison table for all study options). It is noted that for Gas Lift Compressor option, even though the recoverable reserve increase up to double (from 2,16 to 4 MMBO) but Surface Facility cost also increase significantly about US$ 10 M thus make economic indicator is less optimum.

The lowest facility and drilling cost is ESP option, since in this option use of new technology of 6” flexible pipeline along 16 km and only drill two wells. Economics result is also similar with in situ Gas Lift option. However, with operational risks consideration in situ Gas Lift is more preferable than ESP option.

6. Conclusion

Based on our internal study, X Structure can be developed and has been optimized to gain maximum result and safe operation. It required synergetic strategy between subsurface and surface facility to develop marginal field to be feasible and to deliver as a project. Based on technical and economic consideration, the In Situ Gas Lift option is selected to be further studied. By using Braced Monopod type platform completed with topside facility, 8” Carbon Steel Pipeline along 16 km and several subsurface optimization, the development can be forecasted to produce 2000 BOPD and 0.6 MMSCFD, Recalculated NPV is US$ 13.5 M and IRR 28%, under new Gross Split PSC.

7. Recommendation

Oil and gas industry is a dynamic business, where requires breakthrough and innovation to gain profits and maintain safe operation. The development of marginal structures must be performed carefully, to prevent extra cost and maximize oil and gas production.

8. Acknowledgement

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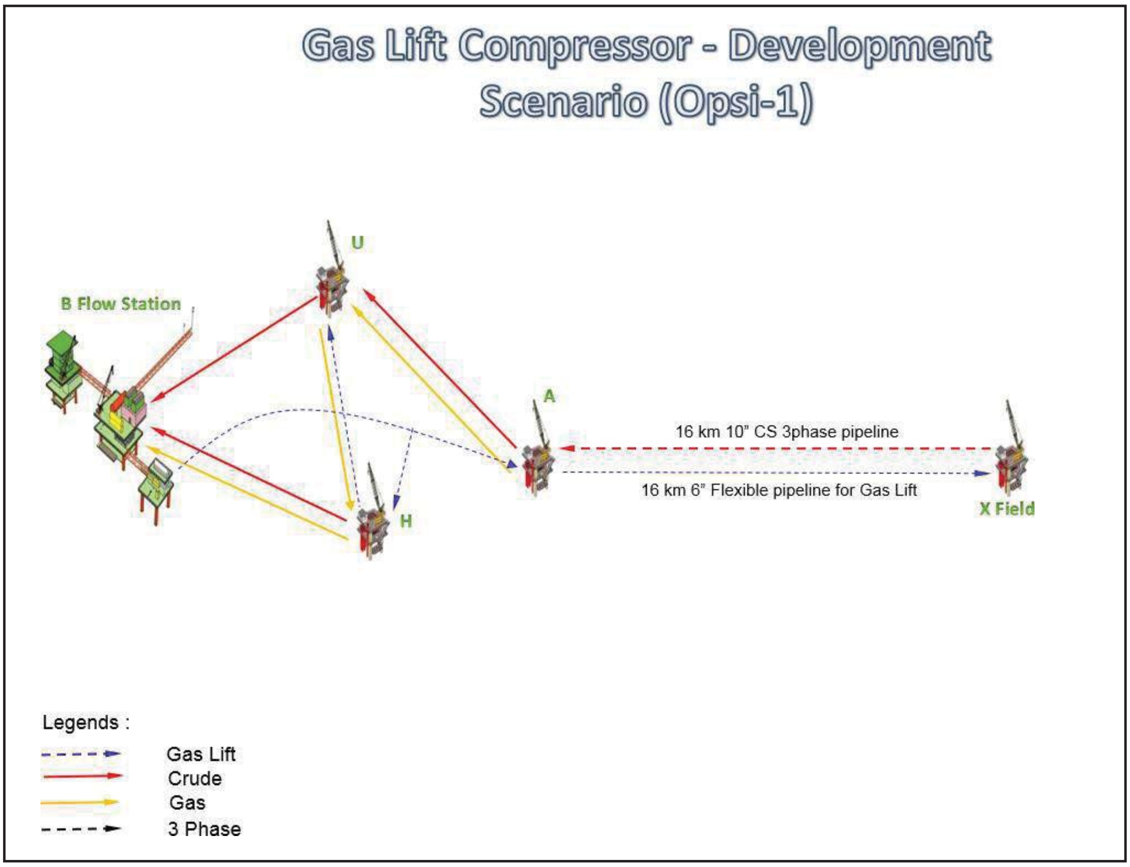
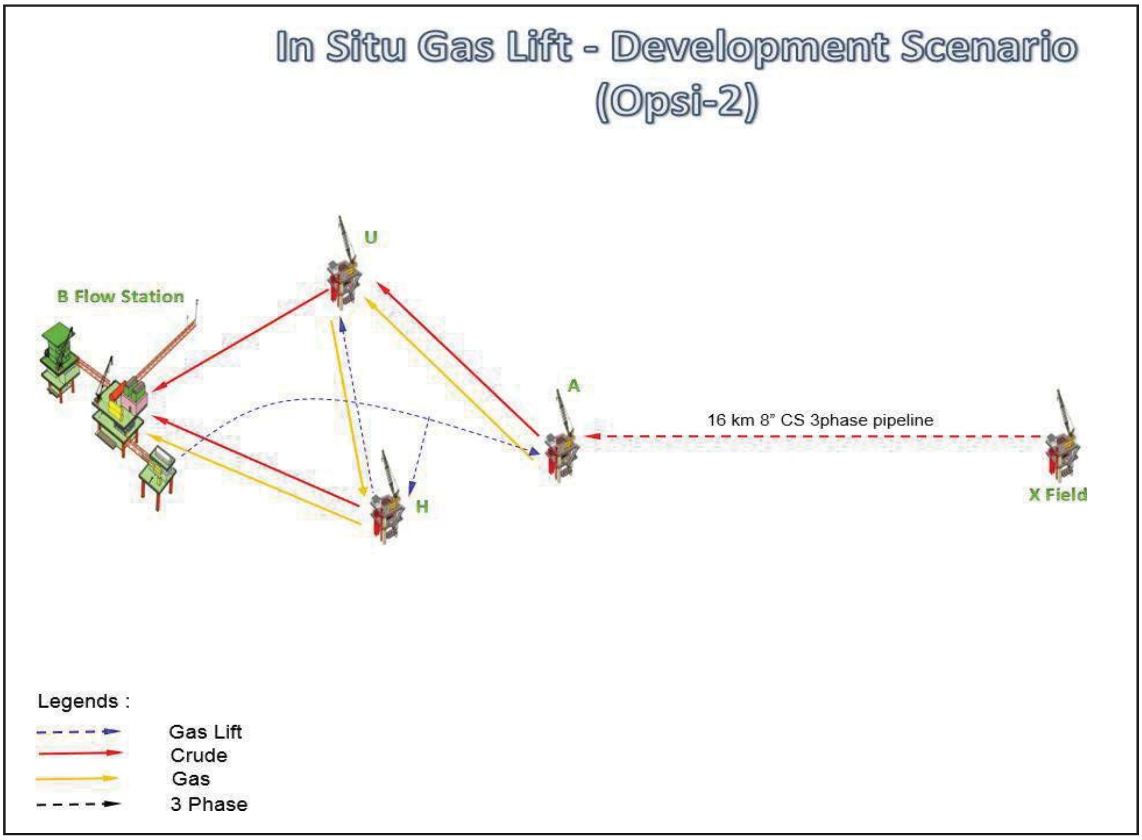
Appendix A. Comparisson Table for All Options

Parameter		Natural Flow	Gas Lift Compressor (Option 1)	In Situ Gas Lift (Option 2)	Electrical Submersible Pump (Opttion 3)
Potential Result	Cost (US$ M)	59.3	70.7	57.5	55.2
	Flowrate (BOPD / MMCFD)	2000 / 1.00	2058 / 1.05	2058 / 0.66	2129 / 0.33
	Recoverable Reserves (MMBO/ BCF)	2.16 / 1.08	4 / 2	3.12 / 1.68	3.75 / 1.88
	NPV (US$ M)	-1.2	**11.1**	**13.5**	**11.6**
	IRR (%)	9.4%	**21.9%**	**28.0%**	**27.2%**
	POT	N/A	2027	2026	2026
Surface Facility Design	Platform type	Braced Monopod	Braced Monopod	Braced Monopod	Tripod
	Production Pipeline Size	10"	10"	8"	6"
	Production Pipeline Material	Carbon Steel	Carbon Steel	Carbon Steel	RTP
	Gas Lift Pipeline	No	Yes, 6" RTP	No	No
	Subsea Cable	No	No	No	Yes , 20 km
	Number of wells	3	3	3	2
Operational Risk	Sand and solid handling	Good (Solid Content 1-5%)	Good (Solid Content 1-5%)	Good (Solid Content 1-5%)	Not Good (Solid Content max 1%)
	Gas Handling	Good (GOR 0 - 10000 SCF/STB)	Good (GOR 0 - 10000 SCF/STB)	Good (GOR 0 - 10000 SCF/STB)	Not Good (GOR max 1000 SCF/STB)
	Well Intervention	Easy (using Wireline unit)	Easy (using Wireline unit)	Easy (using Wireline unit)	difficult (using Hydraulic Workover Unit)
	Surface Maintenance and Operation	Easy (No maintenance for Gas Lift Compressor)	Difficult (Require Maintenace for Gas Lift Compressor)	Easy (No maintenance for Gas Lift Compressor)	Difficult (ESP maintenance periodically every 3 years)
Appraise		Declined	Declined	Selected	Declined

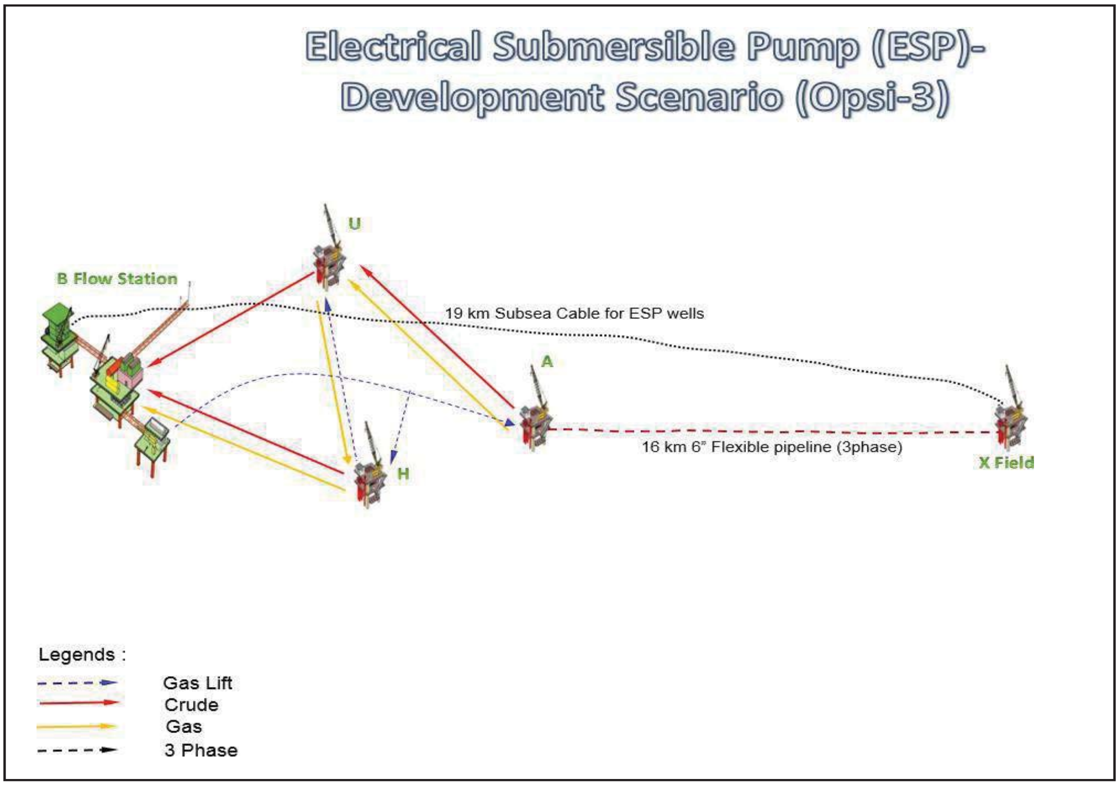
Appendix B. Gas Lift Compressor Development Scenario (Option 1)



Appendix C. In Situ Gas Lift Development Scenario (Option 2)



Appendix D. Electric Submersible Pump Development Scenario (Option 3)



Appendix E. Economic Calculation

ECONOMICS SUMMARY

		POD X FIELD DEVELOPMENT		
Contractor's Economic Indicators		**GL Compressor**	**Insitu GL**	**ESP**
NPV11	$m	11.1	13.5	11.6
Payback	Year	2027	2026	2026
IRR	%	21.9%	28.0%	27.2%

EVALUATION SUMMARY FORWARD LOOKING		**TOTAL**	**TOTAL**	**TOTAL**
Gross Sales Production				
BOE	mmboe	4.25	3.89	3.72
Gas	bcf	1.96	2.73	0.56
Oil	mmbo	3.92	3.42	3.62
Gross Revenue	$m	294.0	260.5	263.7
Gross Opex	$m	48.9	44.1	54.9
Facilities Cost	$m	50.1	36.9	38.5
Intangible Drilling Cost	$m	17.5	17.5	12.3
Tangible Drilling Cost	$m	3.1	3.1	2.1
Total Cost / Gross Revenue	%	40.7%	39.0%	40.9%
Contractor Cash Flow	$m	57.3	55.2	50.3
GoI Take	$m	117.0	103.6	105.5
Government Share of Gross Revenues	%	39.8%	39.8%	40.0%

Assumptions:
- Base Year 2018
- Discount Rate 11.39%;
- Oil Price ICP Base Pertamina
- Gas Price $6.34/mmbtu (WAP Gas PHE ONWJ)
- Contractor Gas Split 61% + Progressive Oil&Gas Price
- Contractor Oil Split 66% + Progressive Oil&Gas Price