Bridge Petroleum Group

SPE Aberdeen European Artificial Lift Forum
Galapagos Field Artificial Lift Selection– 12th February 2021. Jeb Tyrie

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Question: What is the average life of a top class Dual ESP?

Galapagos Development

- The Challenge
- Water Injection
- Concept Select
- **ESP or Gas Lift**
- Flow Control Valve (FCV)
- FPSO option
- Early Development Project

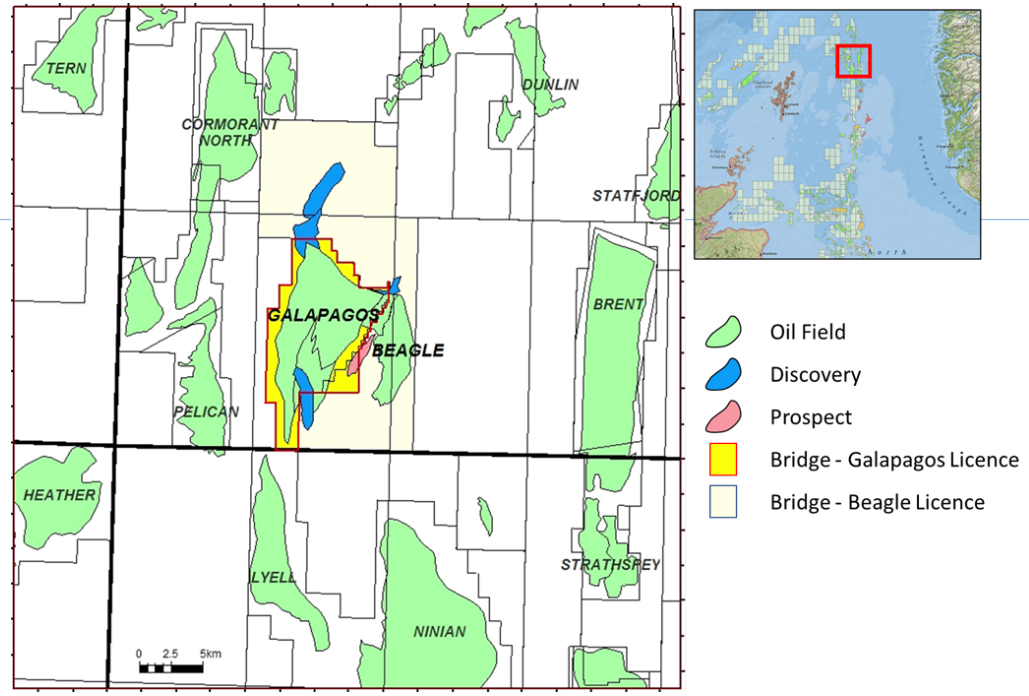
Scenario

- Subsea development with minimal interventions in 30 years
- 11 Producers 6 injectors
- **Must be world class equipment.**

Galapagos Redevelopment

A Dormant Brent Giant

- **Galapagos ideally located for a hub development**
  - Galapagos is located in the heart of the Brent Province in the UKCS
  - Comprised of the now decommissioned NW Hutton Field and an undeveloped southerly extension called Darwin
- **Poorly executed historical development**
  - Only produced 124 mmbbls from 883 mmbbls STOIIP (14% Recovery Factor)
  - Recoveries of 30% are achieved from analogous Brent Fields, but historical issues prevented the NW Hutton development achieving this
  - Modern day data, technology and techniques, commonplace in the present-day oilfield, now provide effective mitigation to the historical issues
- **Low risk re-development identified**
  - Audited resource of 81mmboe identified together with over 100mmboe upside in Bridge's licence hopper



Historical Issues	Present Day Mitigation
Operational • Long reach tortuous wells • Multiple re-entry caused well damage and debris in hole	**Operational** • Simple well design from optimized drill centers • Current day completion and maintenance minimize need for re-entry
Reservoir Management • Incorrect development strategy, not allowing good sweep of the reservoir • Well scaling issues were only just being understood at the time of the development	**Reservoir Management** • Use of history matched geocelluar models identifies the correct development strategy for effective reservoir sweep • Employment of well scaling inhibitors is now commonplace in the industry
Subsurface • Historic seismic not very good quality, and reservoir structure not mappable in detail • Development wells not correctly located	**Subsurface** • Modern reprocessed seismic in place, good imaging of the reservoir structure providing detailed maps • Development well locations can now be optimized

NW Hutton Development

Compartmentalised

Crestal Producers

Line drive injection

Poor Seismic so difficult to place injectors

Sparce placement of injectors in the south

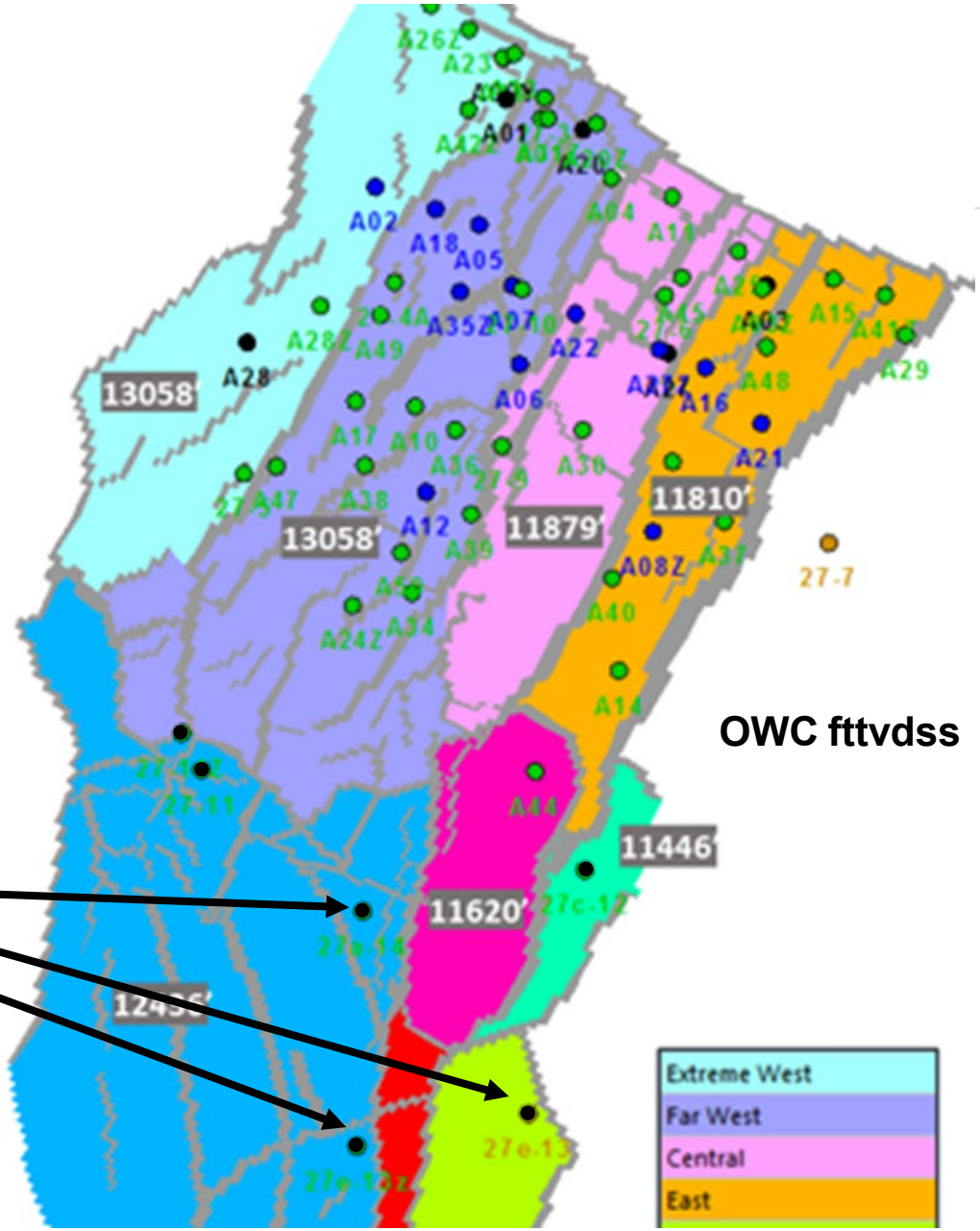
Couldn't reach far south, Darwin area

2012/13 TAQA/Fairfield wells in south

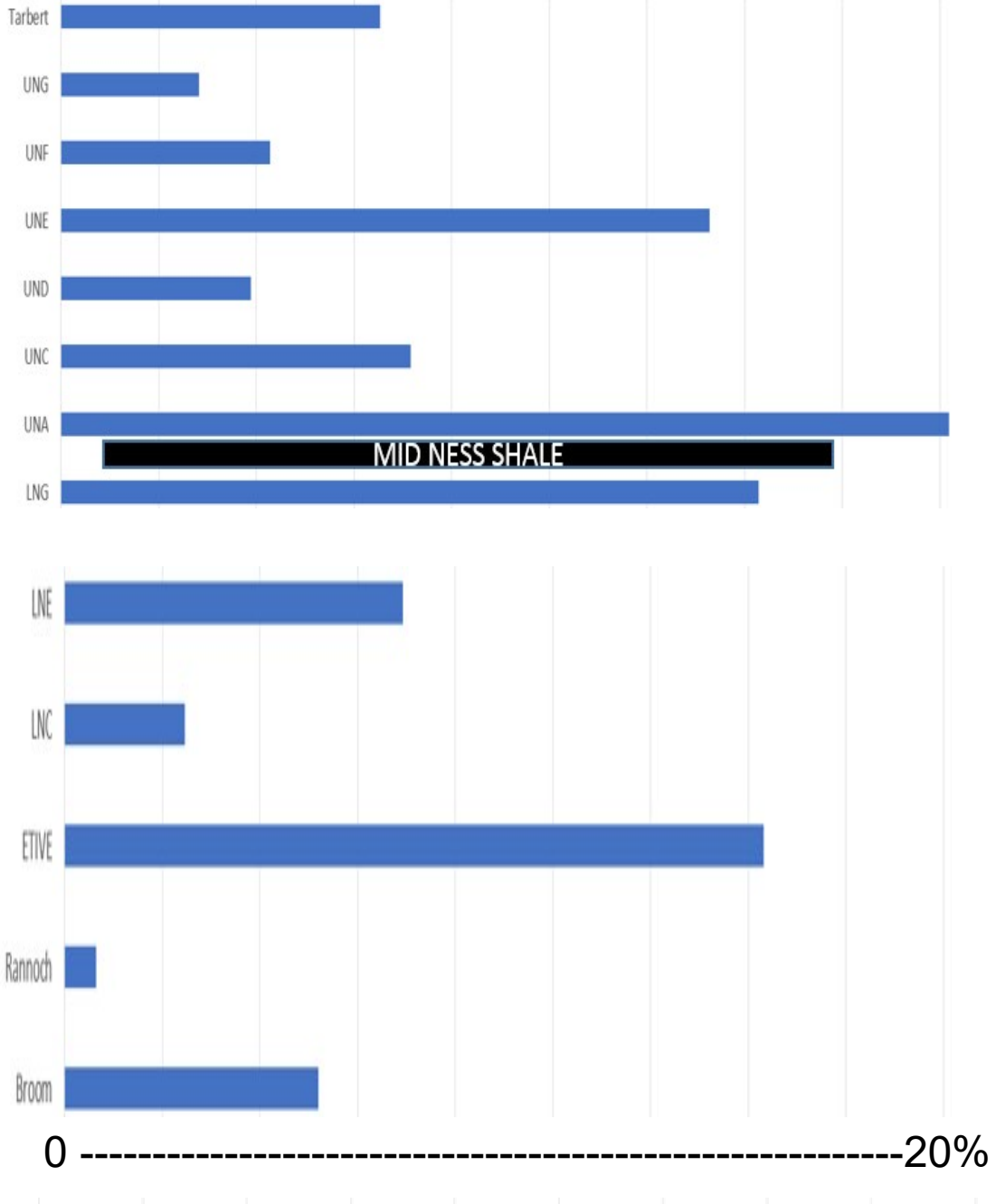
14 oil discovery

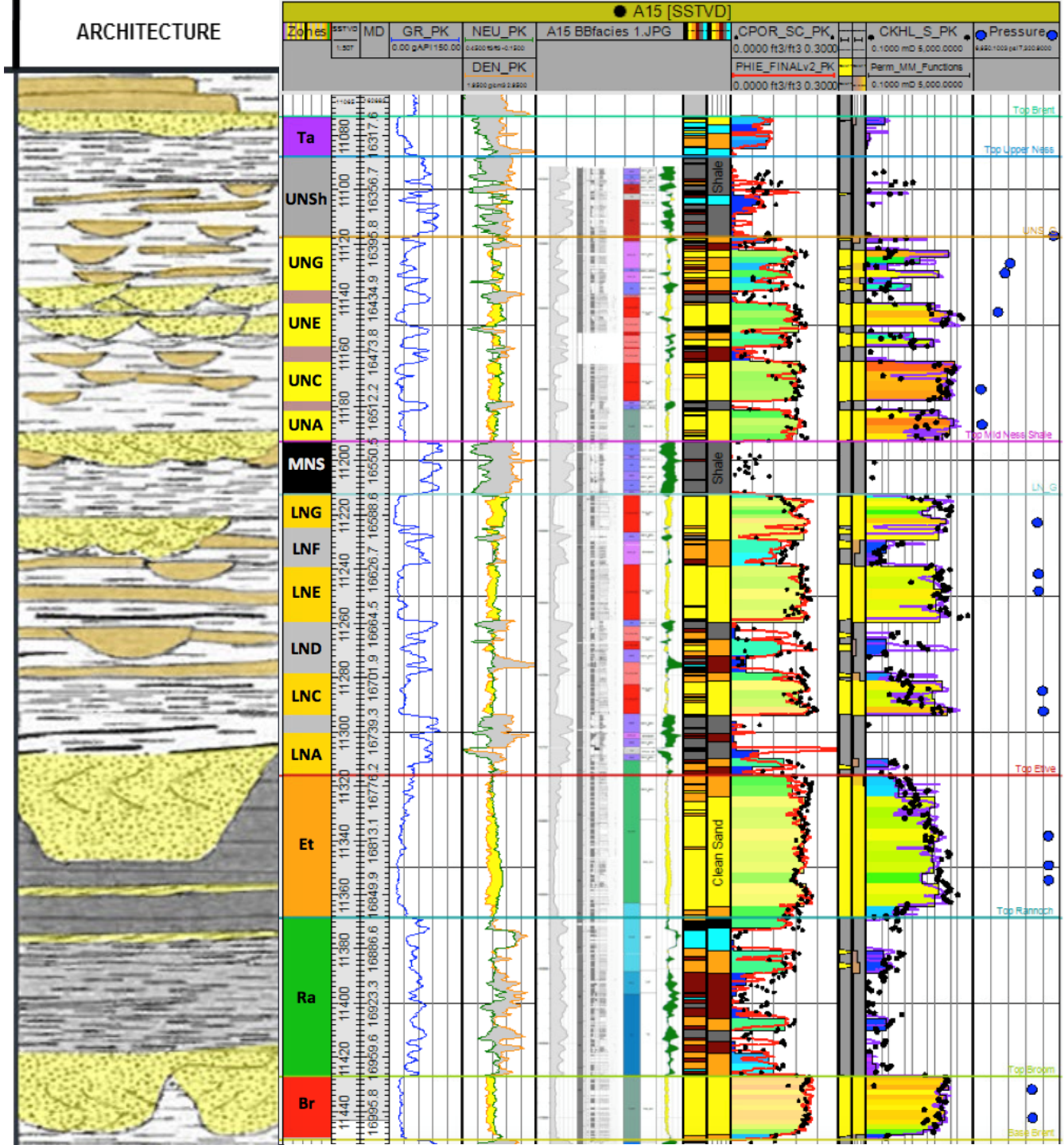
-13 water wet

-13z oil discovery



Summary of all PLTs





DCA vs Simulation; Depletion vs Injection

Early time; depletion only

16 wells (1983-84)

FIPS 3,4,13,14,15.

- DCA vs Simulation; (6%)
- Depletion only 42 mmstbo
- Injection 72 mmstbo
- Injection works !

- But not all Injection schemes are as successful as others

Well	Producer or Future Injector	FIP	Historic mmstb	DCA100 Recovery	Simulator Recovery
A03Z	P	3	2.10	1.24	1.07
A08Z	I	3	6.51	3.04	3.64
A14	P	3	7.27	1.02	1.71
A15	P	3	10.20	4.52	5.16
A16	I	3	0.44	1.27	0.99
A11	P	4	5.92	2.55	3.42
A19	P	4	1.87	1.17	1.26
A22	I	4	0.05	0.00	0.09
A04	P	13	14.59	3.58	3.50
A06	I	13	3.94	3.43	4.03
A07	I	13	2.01	2.45	2.13
A10	P	13	3.51	5.20	5.22
A01Z	P	14	8.6	5.7	5.4
A05	I	14	3.90	5.73	5.47
A02	I	15	0.68	0.71	0.80
A09Y	P	15	0.25	0.00	0.32
			71.8	**41.6**	**44.2**

Galapagos Well Level Evaluation

Impact of managing scale proactively using current technology is significant

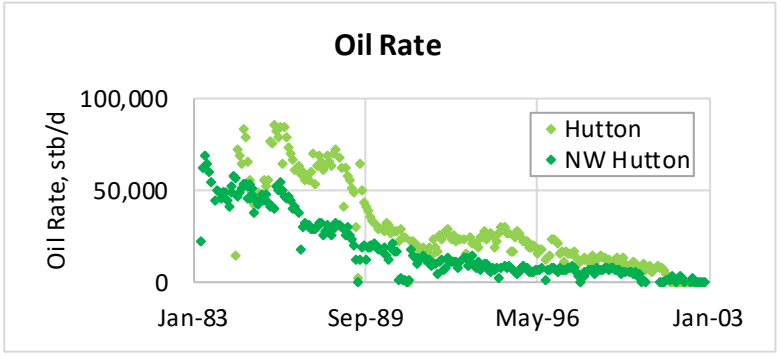
- The impact of managing scale using current available technology was evaluated on legacy production wells coupled with an increase in water injection capacity (i.e. removal of injection bottleneck) in the legacy NW Hutton field.
- Using the history matched reservoir model, the legacy NWH development is able to produce an additional 50 MMbbl oil if scaling was managed proactively using current industry standards until COP date of 01-Jan-2003.
- This conclusion is also based of the possibility of injecting significantly more volumes of water with no zonal control applied.

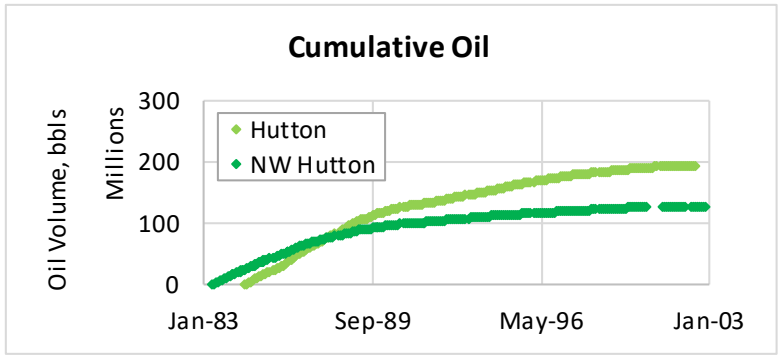
FIP	History Oil Produced	History Water Produced	History Water Injected	NoScale Oil Produced	NoScale Water Produced	NoScale Water Produced
	(MMstb)	(MMstb)	(MMstb)	(MMstb)	(MMstb)	(MMstb)
3	38	29	67	52	182	238
4	13	3	10	16	36	53
12	11	9	18	16	113	89
13	27	25	60	31	155	319
14	22	20	70	34	317	374
15	11	30	2	24	112	39
Total	**123**	**116**	**227**	**173**	**914**	**1113**

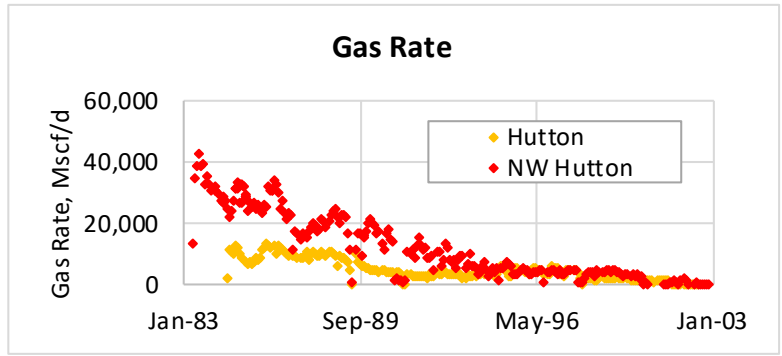
Case	Oil Produced	Water Produced	Water Injected
	(MMstb)	(MMstb)	(MMstb)
History	123	116	227
NoScale	173	914	1113

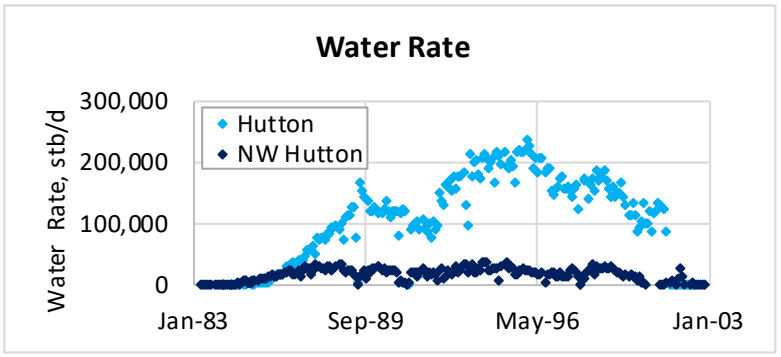
Better Reservoir Management would have added 50 mmstbo

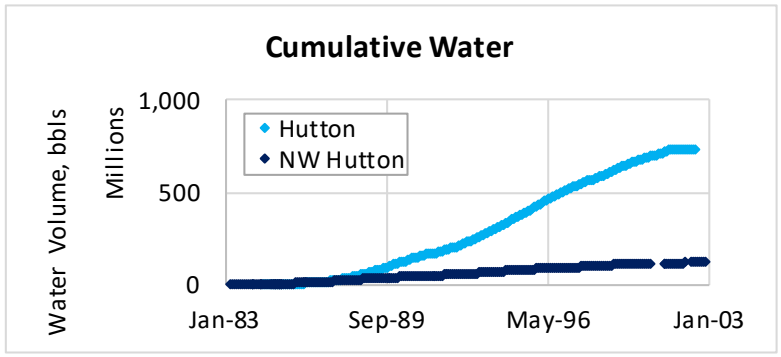
Comparison between Hutton and North West Hutton Production

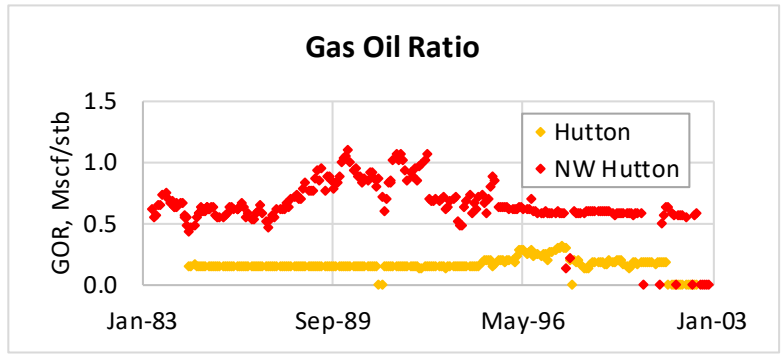


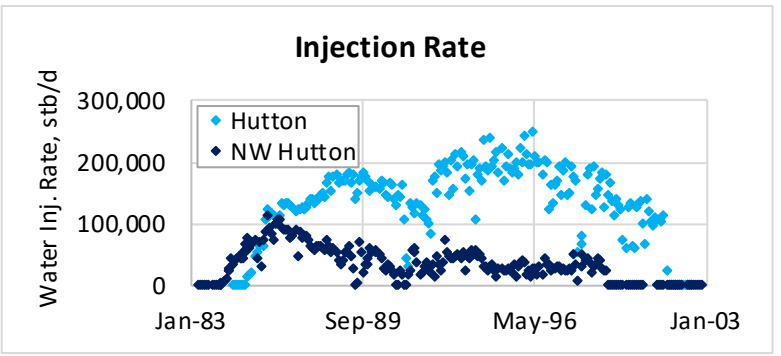


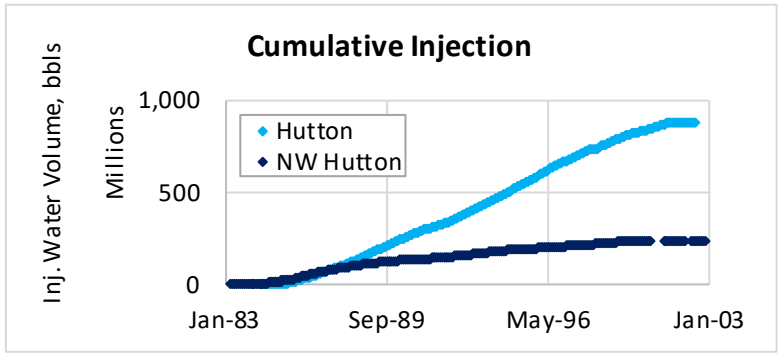


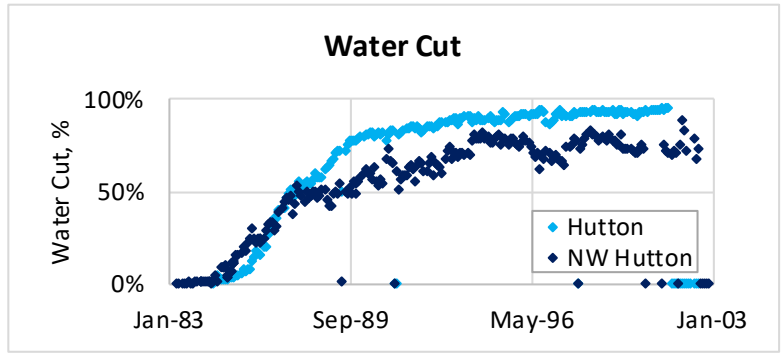








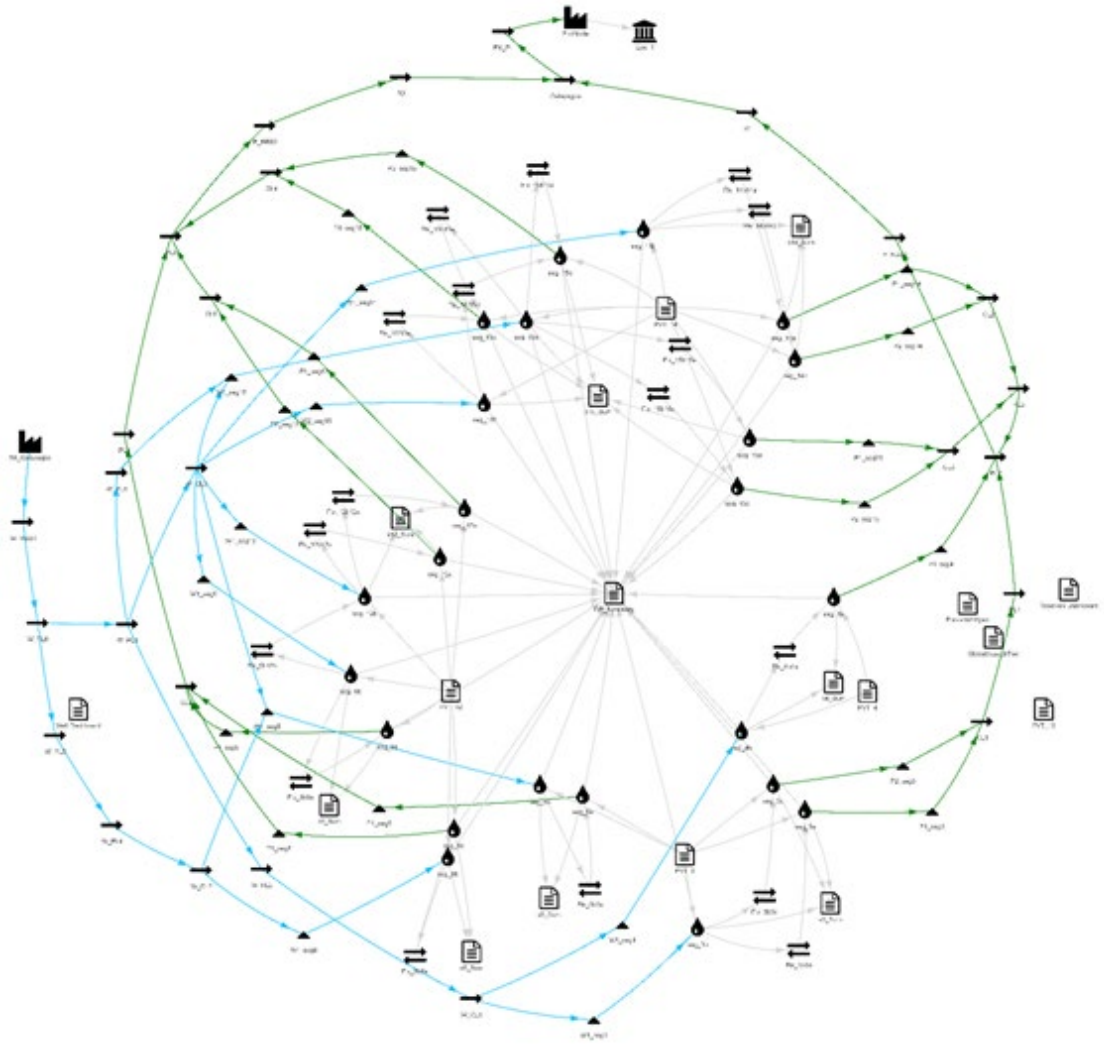




Summary of Concept Select

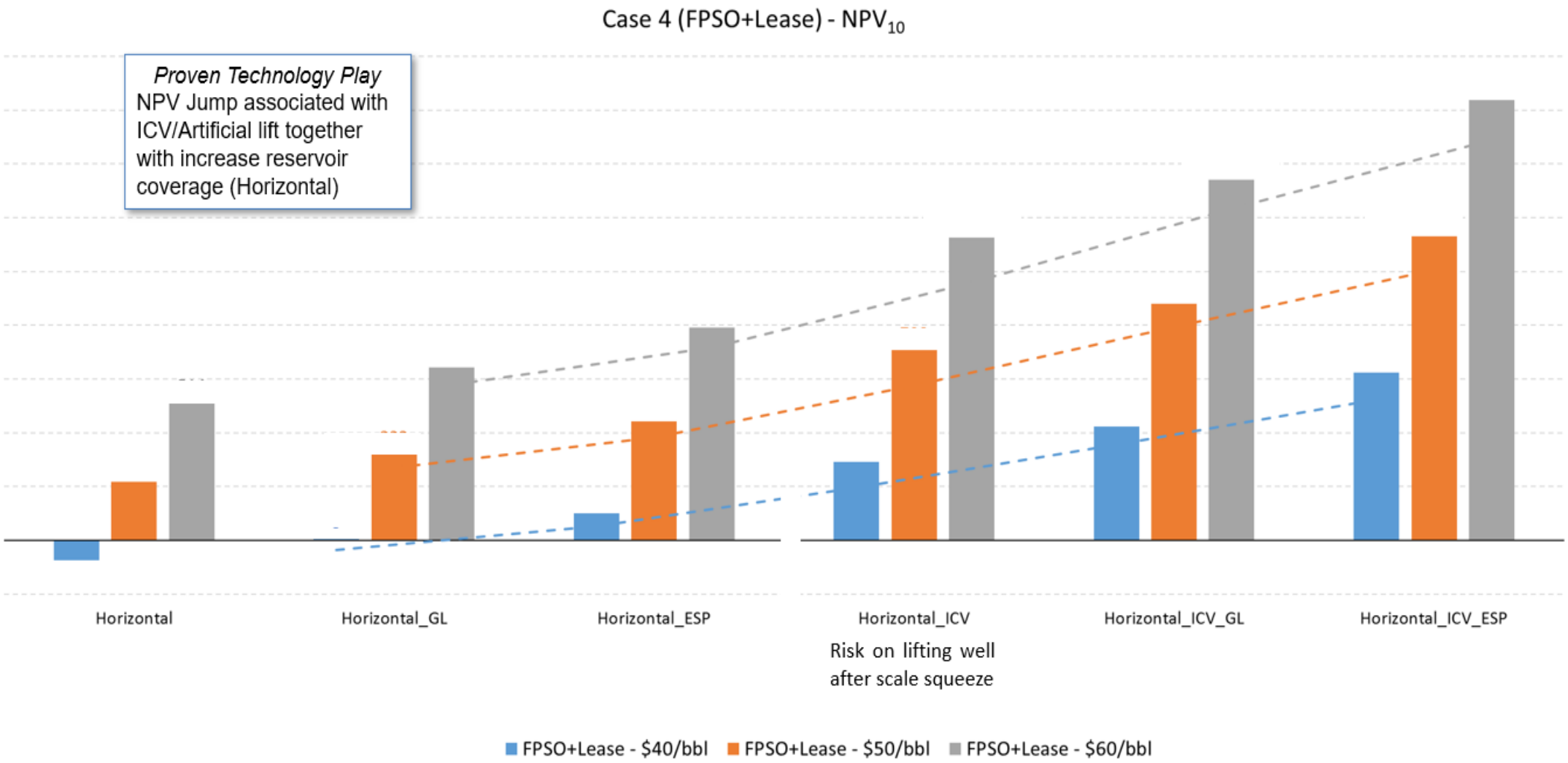
84 scenarios

- The options for Evacuation Route, Well Location, Well Geometry and Down-hole Equipment were clear from the Concept Select process.
- The schematic shows the generic building blocks of the production system, showing:
  - Reservoir PVT descriptions;
  - Reservoir structures and fluxes between structures;
  - Production/injection wells from/to the reservoir structures;
  - Production/injection pipelines and infrastructure;
- Network
  - Pressure Balance, Mass Flow, Temperature
  - Facility options and cost
- **→ Profiles & Cash Flow**

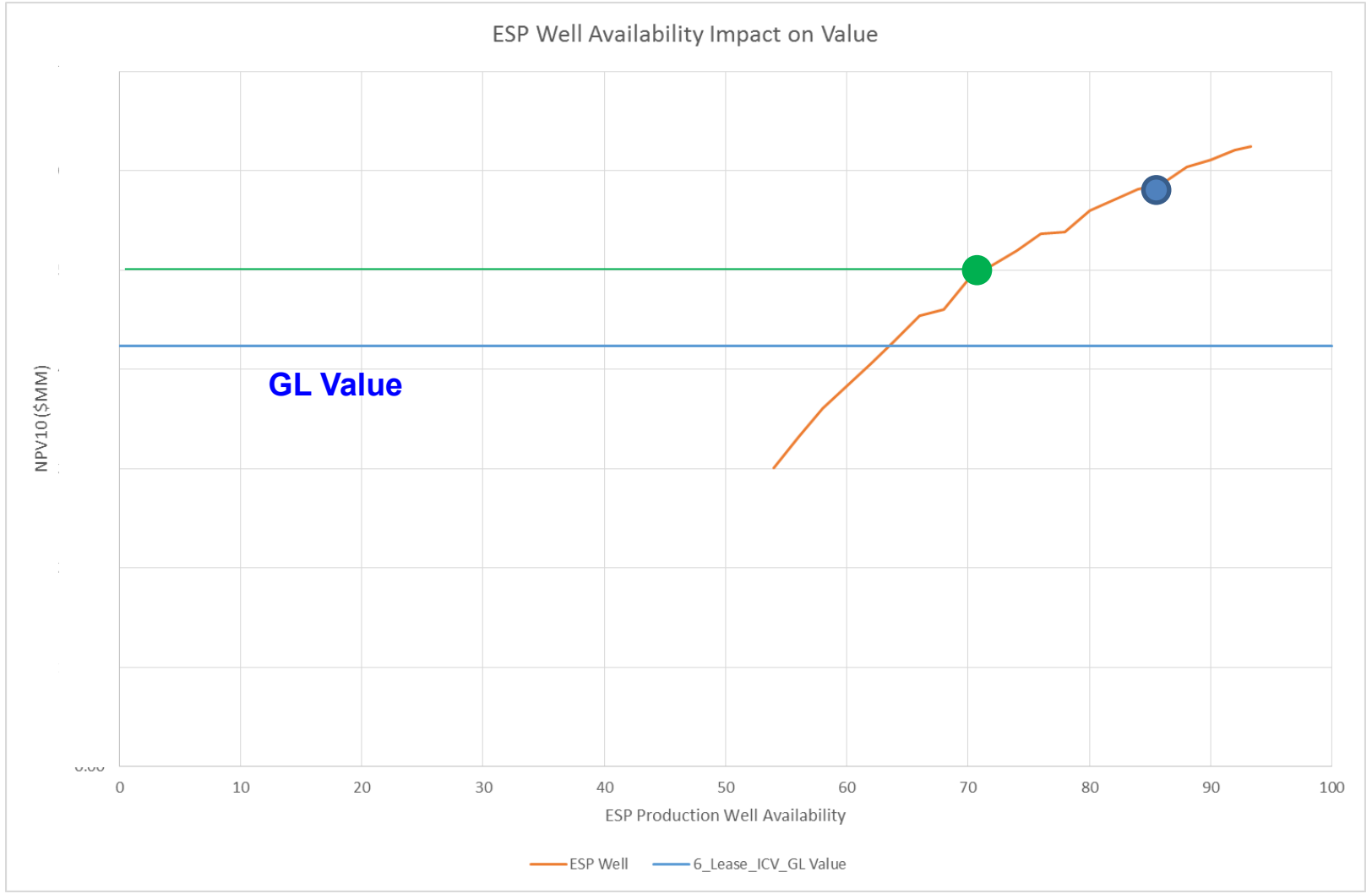


Concept Select FPSO (Lease option)

NPV ($B) of different cases (2018 cases)



ESP Availability – Comparison Against Gas Lift Value



- Using best value case with ESP
- Parameteric analysis adjusting production wells' availability only
- $40/bbl

- 4 Dual ESP workovers per well
- 180day downtime

- ESPs still better than GL

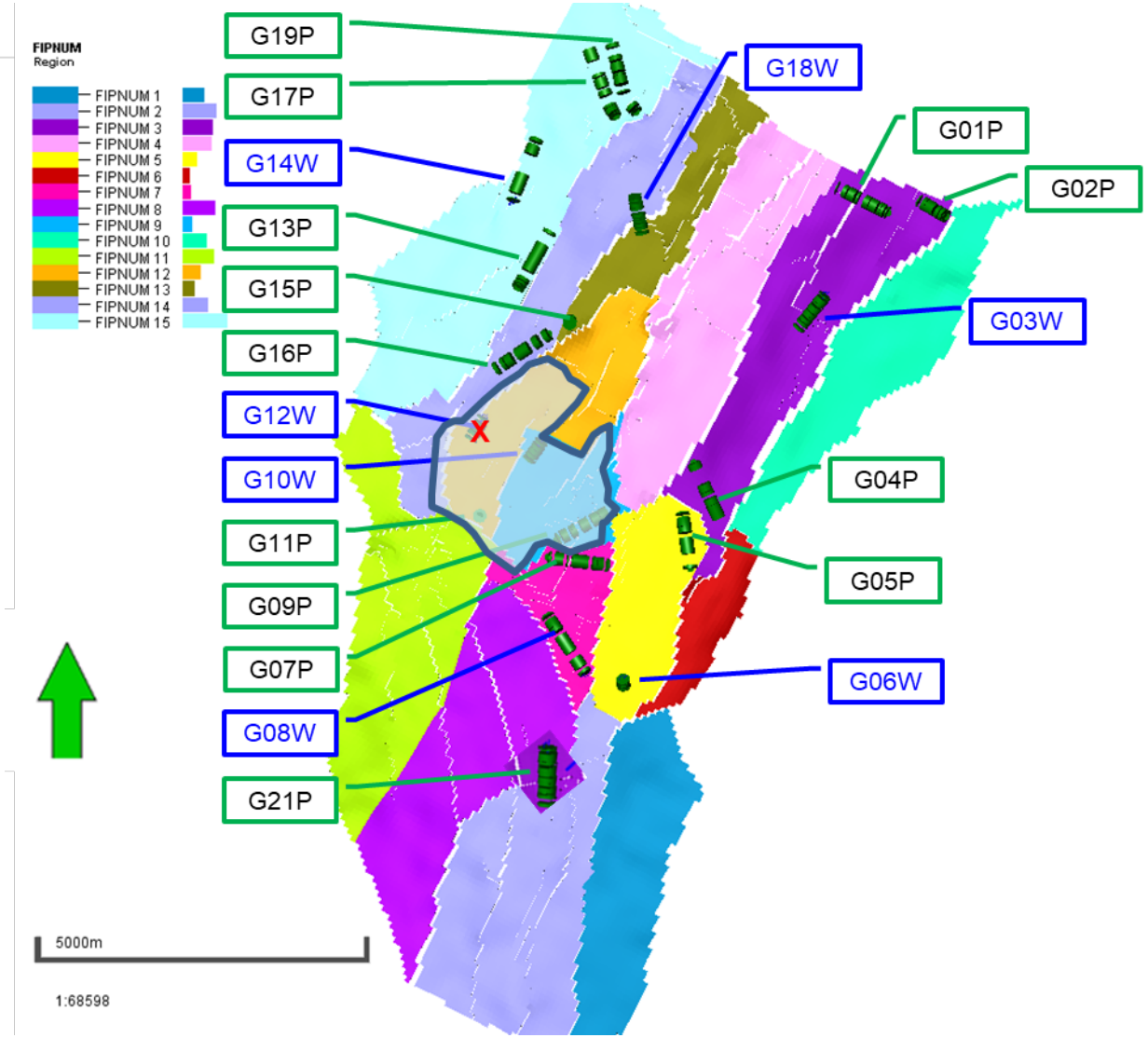
Galapagos Full Field Development

Large FSPO limited gas lift case
11 PRODUCERS 6 INJECTORS

Early Development Project
2 PRODUCERS & 1 INJECTOR

- Small FSPO case
- Tie back case

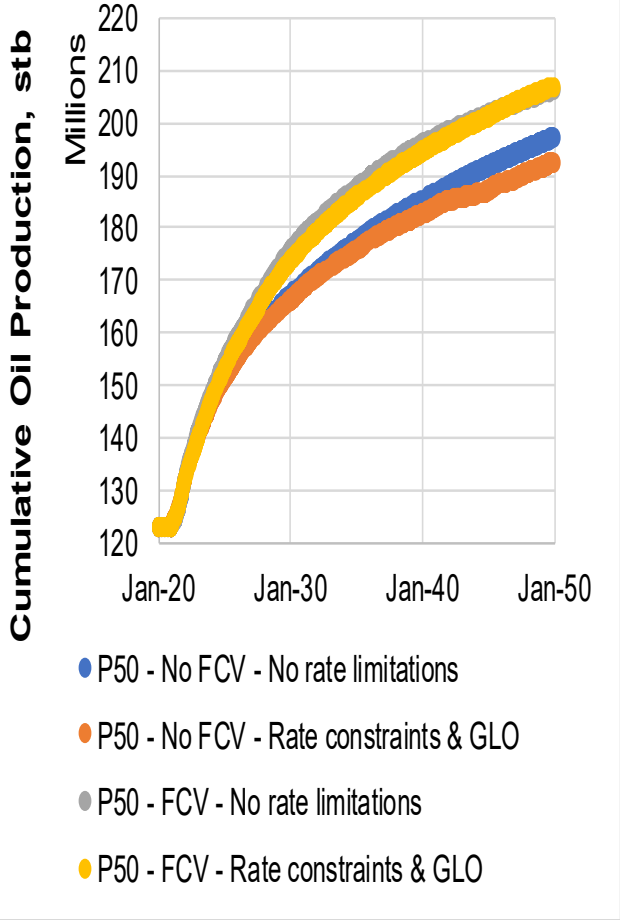
Initiates Cash flow for full Galapagos

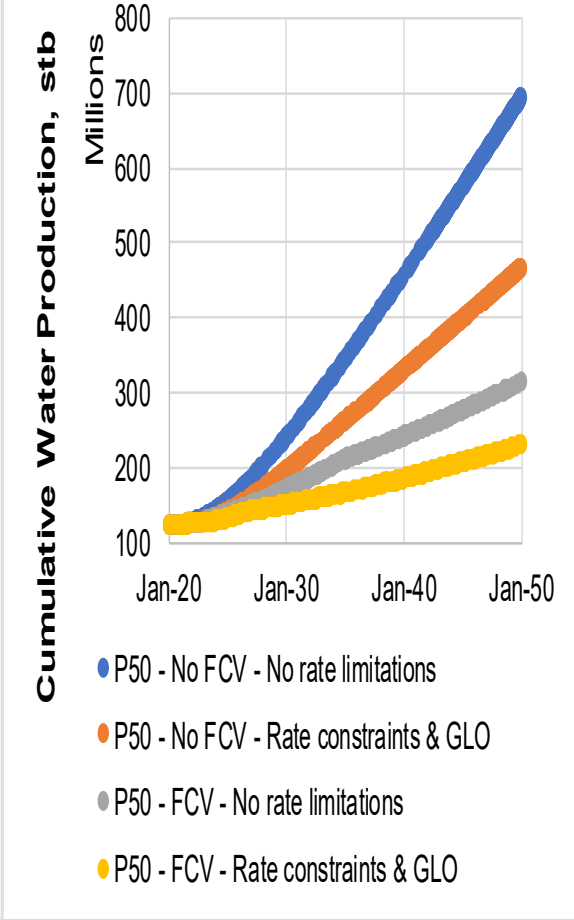


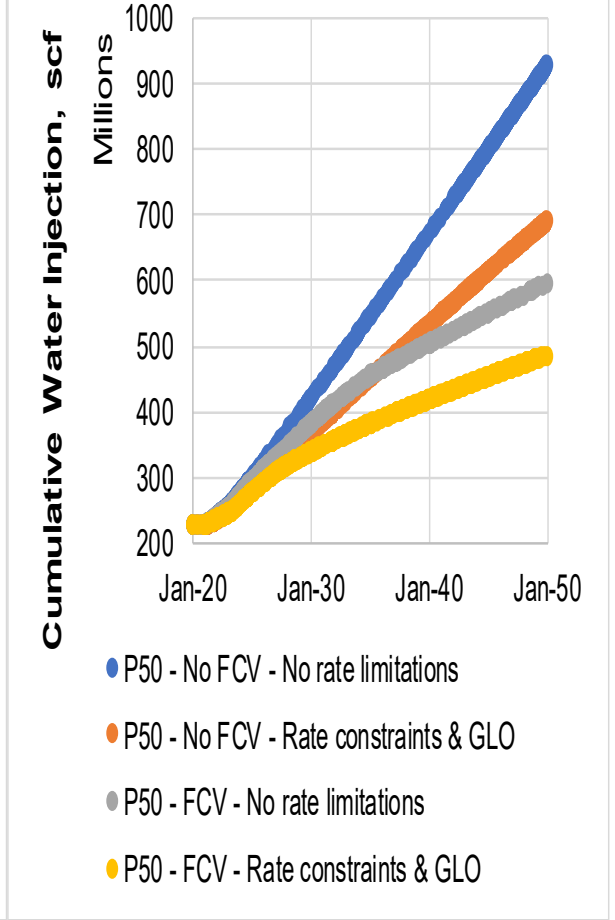
How to Shrink the Facilities (FSPO Case)

FCV Monitoring 90 → 45 MBL/D → Smaller Boat!

Constraints	Oil mmstb	Water mmstb	Injection mmstb
P50 - No FCV	197	692	926
P50 - No FCV Rate & GLO	192	465	688
P50 - FCV	207	312	595
P50 - FCV Rate & GLO	207	230	484



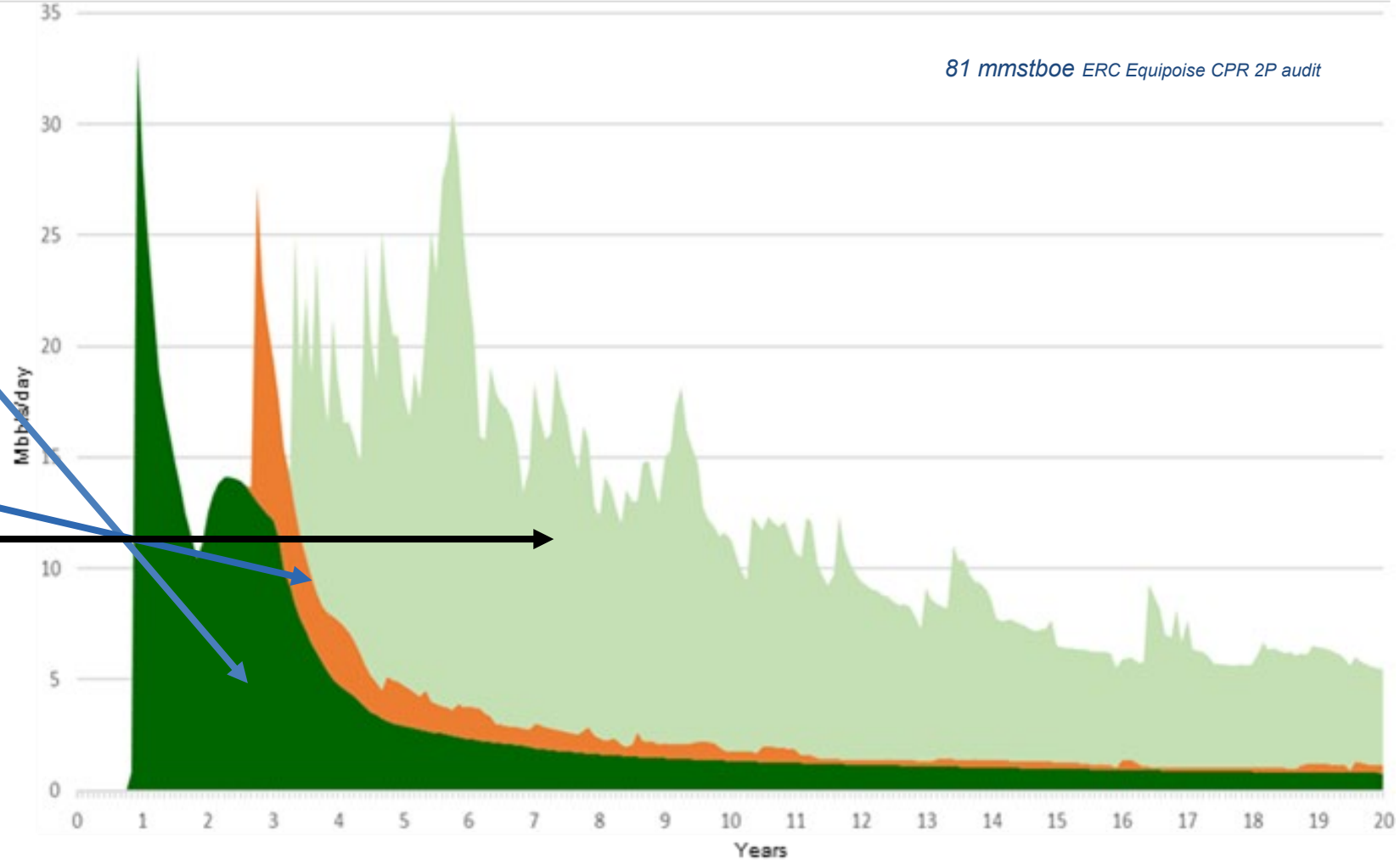




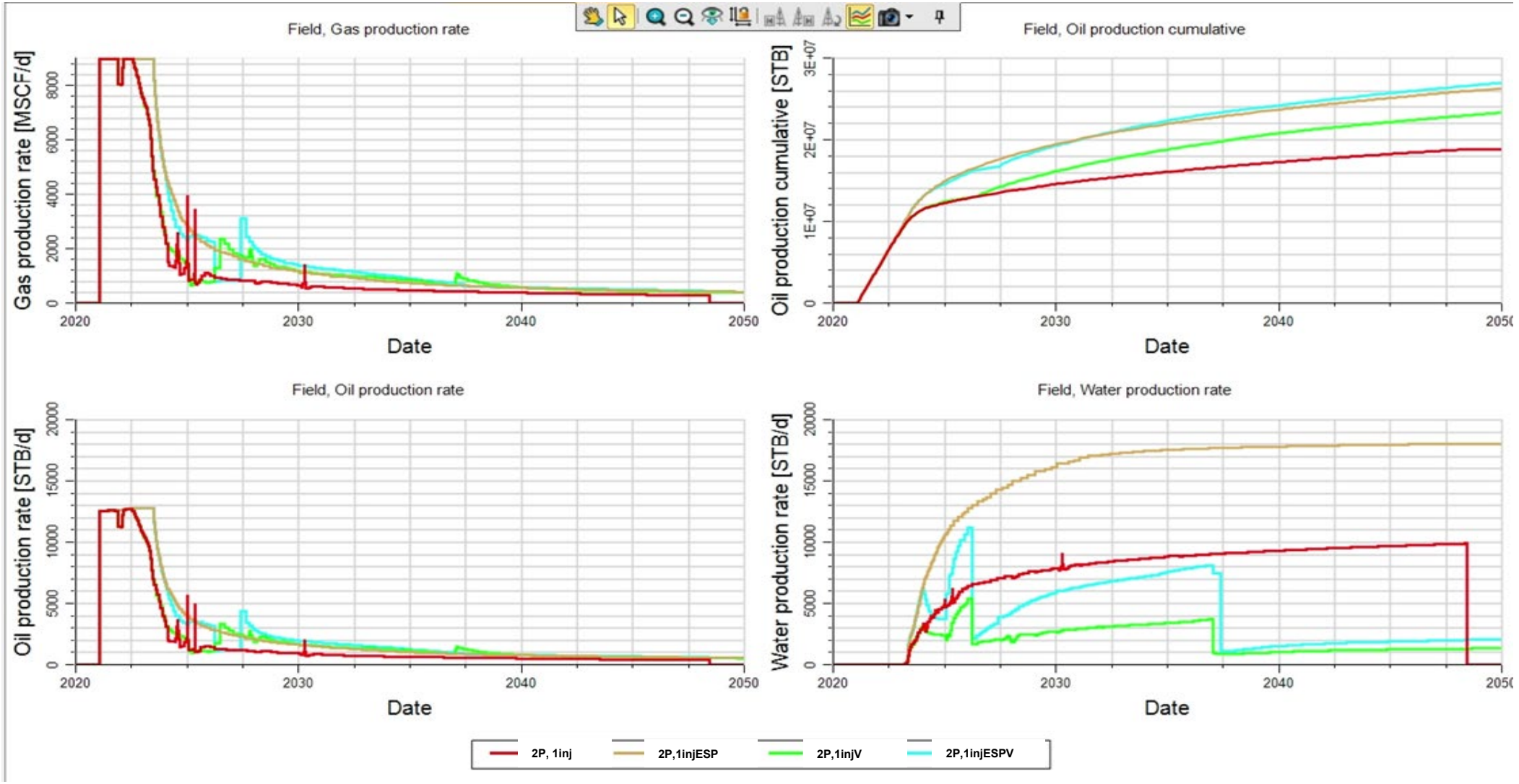
Early Development Project

- Low Capital starter project
- Self funding
- **Low cost 3 wells; 26 mmstboe**
- Extra well; 5 mmstboe
- Full 2P drilling; total 81 mmstboe

- Infield RF to 30%; +60 mmstboe
- Hub potential +41 mmstboe



FPSO Case, No Gas Lift. Mixing ESPs and FCVs



Alternative AICD, less complex, smaller benefit

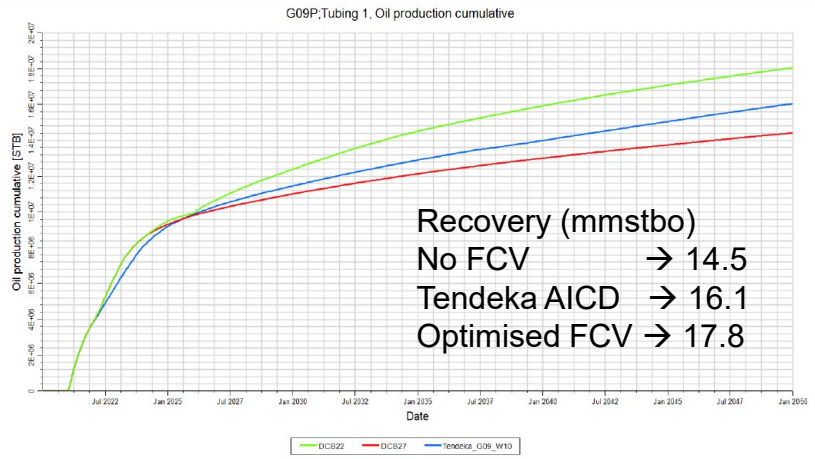
Early Galapagos project
2 Producers + 1 Injector

Green field area
Gas Lift; 5mmscf/day / well

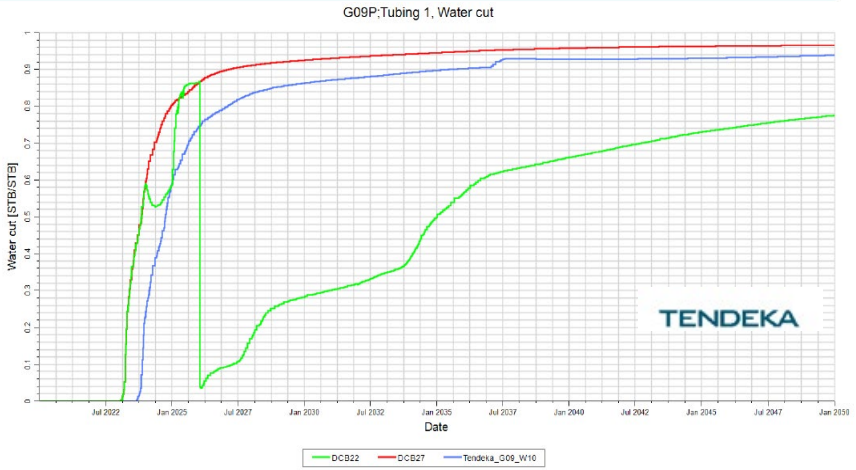
AICD installed on Producer G09p and Injector G10w
FCVs remain on G11p

Field Incremental Recovery
No FCVs vs AICD vs FCV
Oil 1.6 cf 3.3 mmstbo
Water -29 cf -76 mmstbw
Injection -52 cf -83 mmstbw

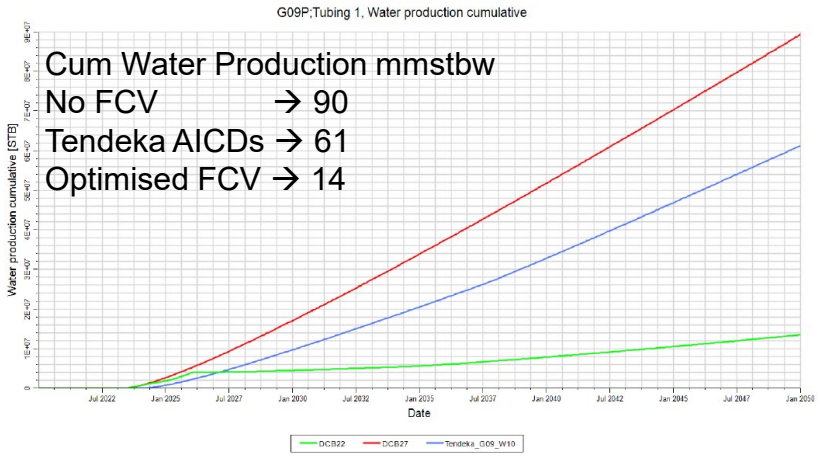
Well G09P Cum. Oil Production



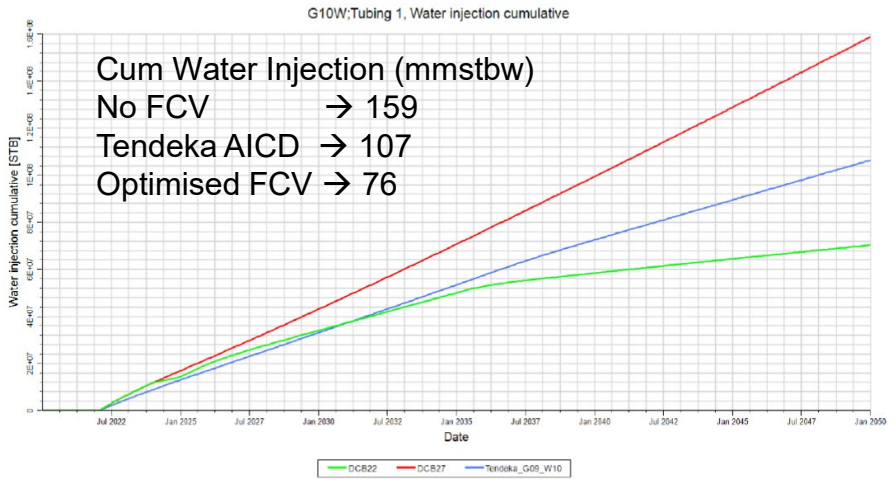
Well G09P Water Production



Well G09P Cum. Water Production



Well G10W, Cum. Water Injection



Conclusion

- **We still don’t know the average life of a top class ESP**
- **We estimate a Dual ESP will last, on average, 5 years**
- **We like FCVs**
  - Reduce water, Reduce Power, Reduce CO2,
  - Increase Oil, Increase data, Increase field Recovery
- **We wouldn’t favour ESPs and FCVs in the same well**
- **For the more conservative**
  - AICDs could be a good alternative
  - Tracers for data
- **Our Base case is 30 km tieback**
  - **Greenfield area so no immediate FCV benefit**
  - Gas Lift due to distance
- **Under constant review**

Questions

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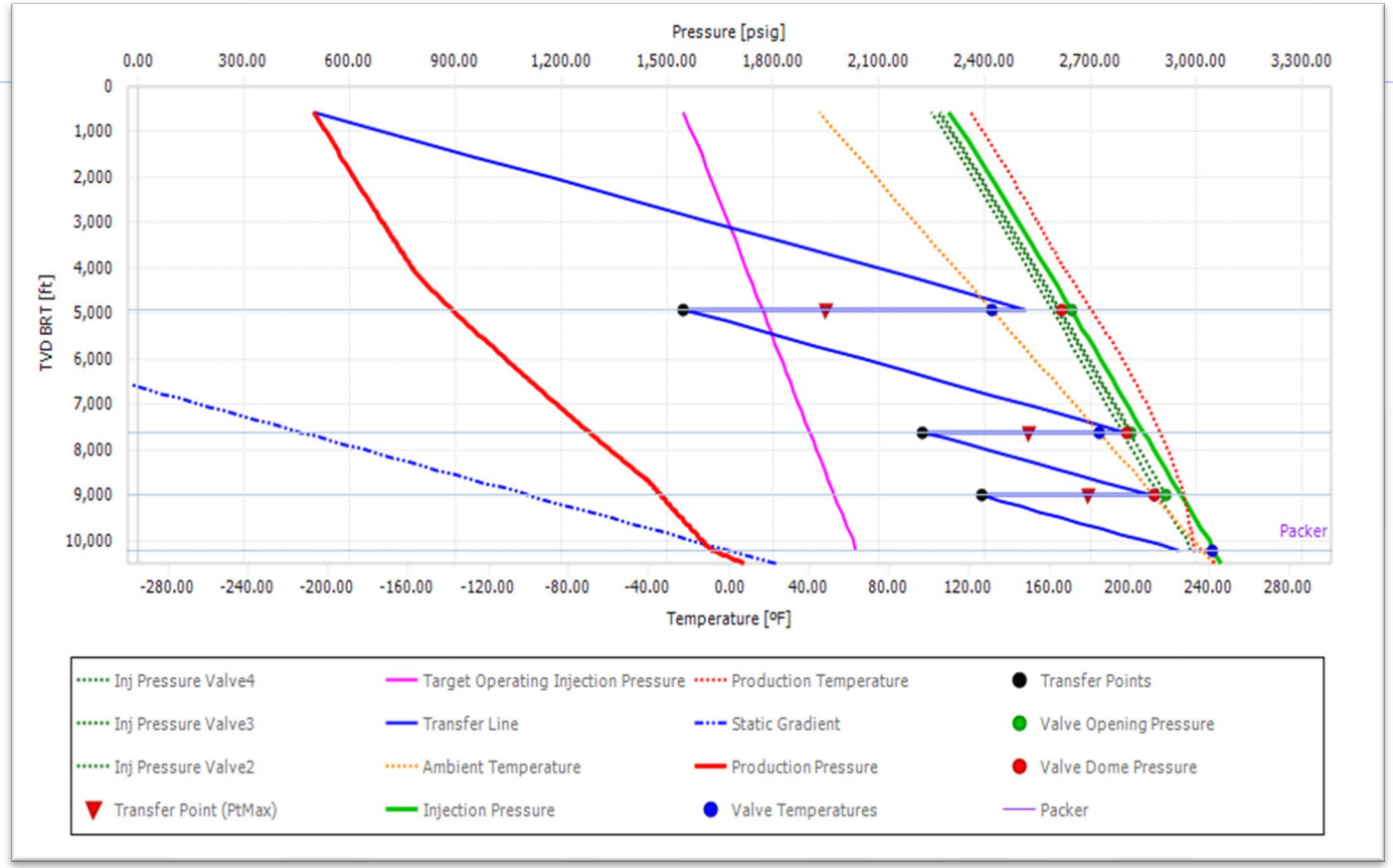
Producer: Base Case Completion and Gas Lift Design



SPM. Num	Valve MD (ft)	Valve TVD (ft)	Valve Model	Port Size	Ptro (psig)
1	5399.25	4900	Unloading IPO	3/16	2319.1
2	9281.14	7600	Unloading IPO	3/16	2260.6
3	11251.76	9000	Unloading IPO	1/4	2316.2
4	12667.34	10200	Injection Orifice	5/16	
SPM. Num	Valve Temp (ºF)	Close Press at Surface (psig)	Open Press at Surface (psig)	Ptmin (psig)	Inj Press Drop b/w Valves (psi)
1	131.09	2275	2300	1546.9	0
2	184.64	2260	2272.6	2224.9	27.47
3	212.41	2239.3	2265.9	2395.2	6.67
4	241.58			2315	15