Flow Assurance Technical Section Webinar

Sanction in 3 Months

(An Engineering Perspective for Deepwater Subsea Tieback)

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Project Summary

- Company A has drilled 2 wells & 3 side tracks
- Data Available:
  - PVT data of fluids collected during MDT (Oil API ~30, GOR ~1,000 scf/stb, Water salinity ~18%)
  - Pressures and logs from the wells
- Host operated by Company B (no ownership in wells yet)
- Host has capacity for 2 production risers and an umbilical, ~30-mile subsea tie-back
- Processing capacity up to 15,000 blpd and associated gas
- Expansion of HPU, control system and other functions to support tie-back is feasible
- Different ownership production, measurement and allocation using multiphase metering
- Desired production within 1 year (or ASAP)

Investment Decision in 3 months (lease expiry)!

Standard Design

- Instrumentation (PT sensors)
  - bottomhole (max 2 zones individually)
  - upstream and downstream of choke
  - possibly at manifolds
- Horizontal Tree
  - subsea choke optimized for appropriate well control & drawdown
- Flowloop (potential pigging) – could be optimized (wet / pipe-in-pipe)
  - Direct electrical heating considered
- Riser based connections for future artificial lift (pumps, gas lift …)
- Frac pack with sand screens
  - sand production not anticipated
- Chemical injection
  - largest umbilical tube limited to 0.75" ID
  - 1x oil-based chemical; downhole
  - 1x water-based chemical; downhole
  - 1x LDHI – at subsurface safety valve (SCSSV)
  - 1x methanol – at tree and SCSSV
- Flow rate measurements (oil, gas, water)
  - Per well: multiphase meter at well jumper
  - Per riser: multiphase meter and/or separator

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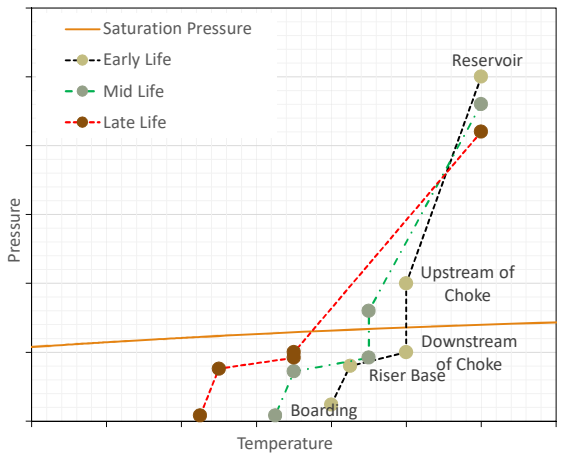
Vapor Liquid Equilibrium



- Primarily oil in the reservoir (water influx with depletion)
- Wellbore expected to see phase change in late life (below bubble point)
- Flowline and riser always expected to be below bubble point (gas, oil and water)
- Expected strong water drive and hence, significant water production
- Insulation to be determined (PIP unlikely to retain temperatures above wax appearance temperature)

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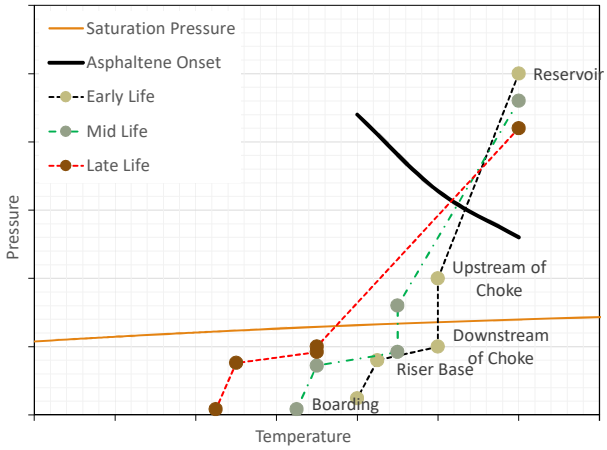
Asphaltenes



- Near wellbore reservoir pressure above asphaltene onset pressure
  - Formation damage from asphaltene precipitation not anticipated
- Asphaltene precipitation in wellbore from day 1
  - Mitigated using continuous asphaltene inhibitor injection
- Pressures in flowline and riser below bubble point, no asphaltene deposition expected (per previous experience)

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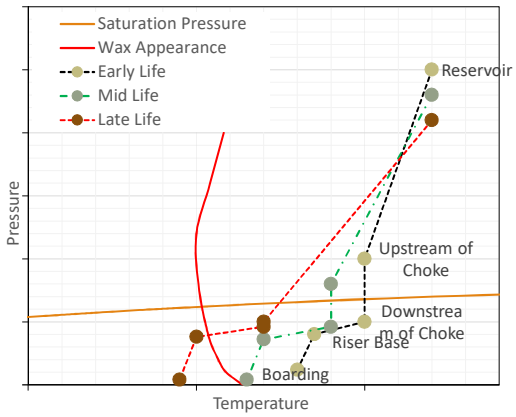
Wax



- Pipe in pipe insulation impractical for heat retention at lower flow rates
- With wet insulation, temperatures fall below wax appearance temperature in flowline and riser
- Hot oil circulation or mechanical remediation of deposits desired near host
- Based on export oil (degassed) experience, expected wax deposition is low and mitigated using continuous chemical injection
  - Stable hydraulics (delta P)
  - Not pigged in over a decade of operayions

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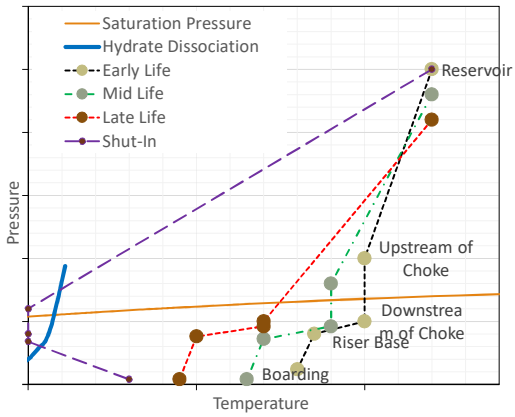
Hydrate



- Anticipated water salinity ~18%
- Flowing conditions outside hydrate conditions
- Long shut-in and restart enter hydrate zone
- Hydrate related plugging very low
  - 4 analogs (high water salinity)
  - bathymetry to be considered
- Dead oil circulation – possible but impractical
  - dead oil not stored, need buy back
  - long circulation time

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Flowline (Single vs. Flow Loop)

- Heat loss resulting in wax and hydrate deposition is a possibility, albeit very low

- Single flowline with electrical heating considered;
  - could result in ~6-month delay; rejected
  - possible use of I-tube for power umbilical; not desired

- Flow loop (2 flowlines) advantages:
  - accommodate future upside
  - standard kit; expedient execution meets project goals
  - experience in installation and operation

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Risk Summary

Yrs	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Asphaltene															
Wax															
Hydrate*															
Scale*															
Corrosion*															
Emulsion*															

*Assumes water breakthrough in year 3.

- ❑ Asphaltene deposition in the wellbore is the greatest risk with uncertainty in chemical performance & cost of remediation.
- ❑ All other risks can be mitigated using a combination of chemicals and operating procedures as well as remediated with relatively lower costs.

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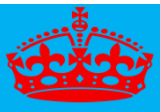
Intervention

- ❑ Pigging capability of flow loop (wax, corrosion)
  - ❖ smart pigging possibility
- ❑ Mechanical Interventions (asphaltene, wax, hydrate)
  - ❖ Direct vertical access to riser (coiled tubing, etc)
  - ❖ Rig for well bore
- ❑ Fluid Interventions (asphaltene, wax, hydrate)
  - ❖ Direct vertical access to riser (coiled tubing, etc)
  - ❖ Access at manifolds (coil?)
  - ❖ Riserless technology for well bore
  - ❖ Bullheading
  - ❖ Umbilical tubes (chemical spotting close to injection locations)



Keep Calm

It's

Nothing New

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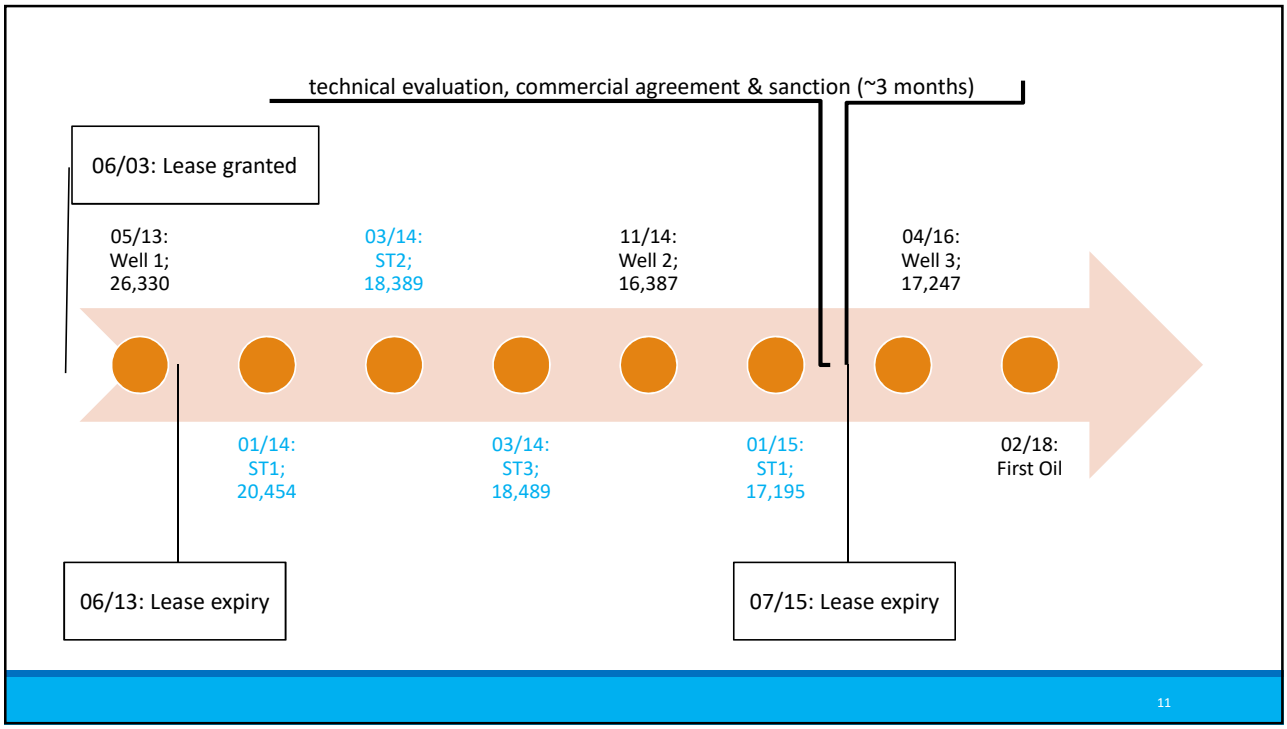

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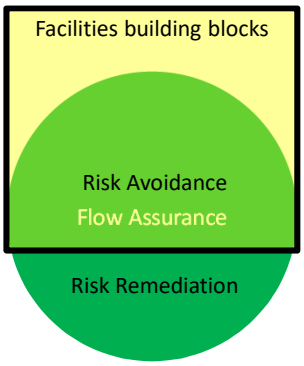
Summary

- Standardized LEGO-like subsea facilities
  - requires optimal supply-chain
  - compatible multi-vendor equipment (desired)
- Consider flow assurance risks in 2 parts
  - risk avoidance with available facilities
  - risk remediation, if manifested
- Consider high reservoir performance uncertainty while engineering fit-for-purpose facilities
- Does shorter engineering time matter?



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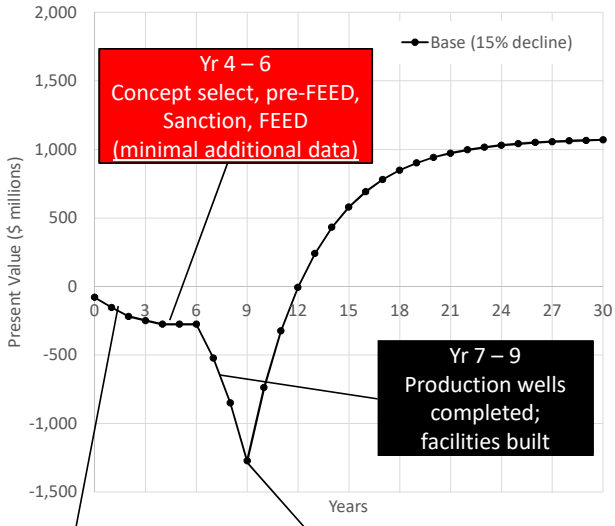
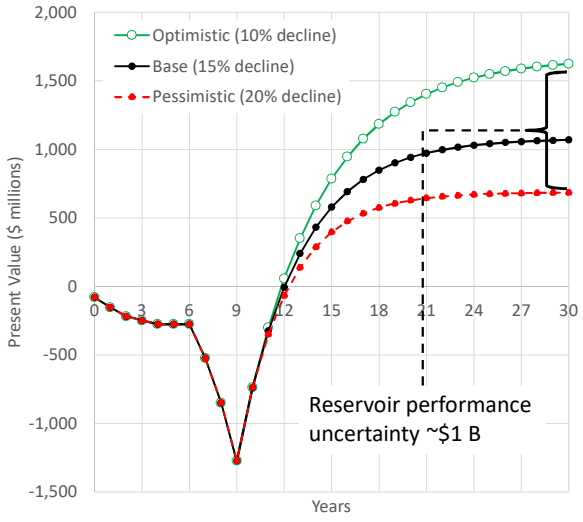
An Example Deepwater Development Economics - Uncertainty





D&C and facilities CAPEX are assumptions, dependent on market conditions

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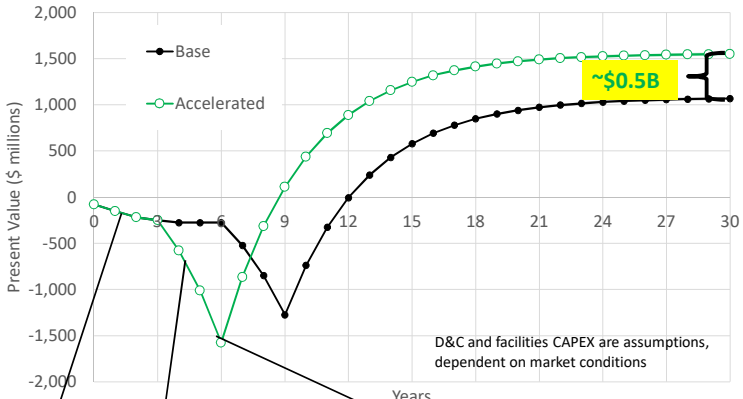
An Example Deepwater Development Economics - Acceleration

Greenfield ~120 MMSTB recoverable



- Yr 1 – 3: Exploration and appraisal wells
- Yr 4 - 6: Concept select, FEED, production wells completed; facilities built
- Yr 6: First oil; positive cash flow

- ❑ Improved project economics
- ❑ Base case: significant uncertainty
- ❑ Accelerated case: 50% of uncertainty value captured
- ❑ Questions:
  - ❖ Is fit-for-purpose design for each project necessary?
  - ❖ Is such a short timeline safely achievable?
  - ❖ Does the fast approach increase risks?

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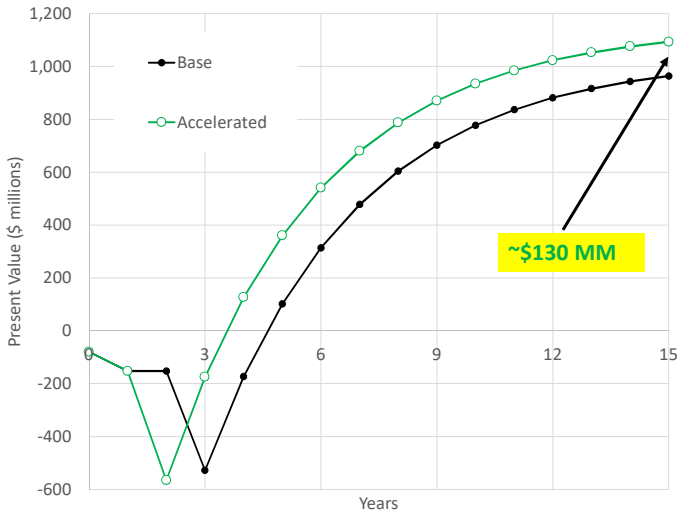
An Example Deepwater Development Economics - Acceleration

Brownfield subsea tieback ~65 MMSTB recoverable



D&C and facilities CAPEX are assumptions, dependent on market conditions

- ❑ Project economics are better with acceleration of greenfield and brownfield projects (even subsea tiebacks) – Duh!
- ❑ Commonality in equipment design and operating philosophy improves project economics.
- ❑ Collaboration amongst operators and suppliers is essential.

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Subsea Development Utopia

- ❑ Minimize Reservoir Uncertainty (Water): Challenge to Operators
- ❑ Standardized LEGO-like Equipment: Challenge to Suppliers
- ❑ Create Subsea Equipment Portfolio: Challenge to Operators
- ❑ Shorten Engineering Timeline: Challenge to Engineering / Operators
- ❑ Optimal Supply Chain: Challenge to Operators (share development timelines / plans)

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Thank you!

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