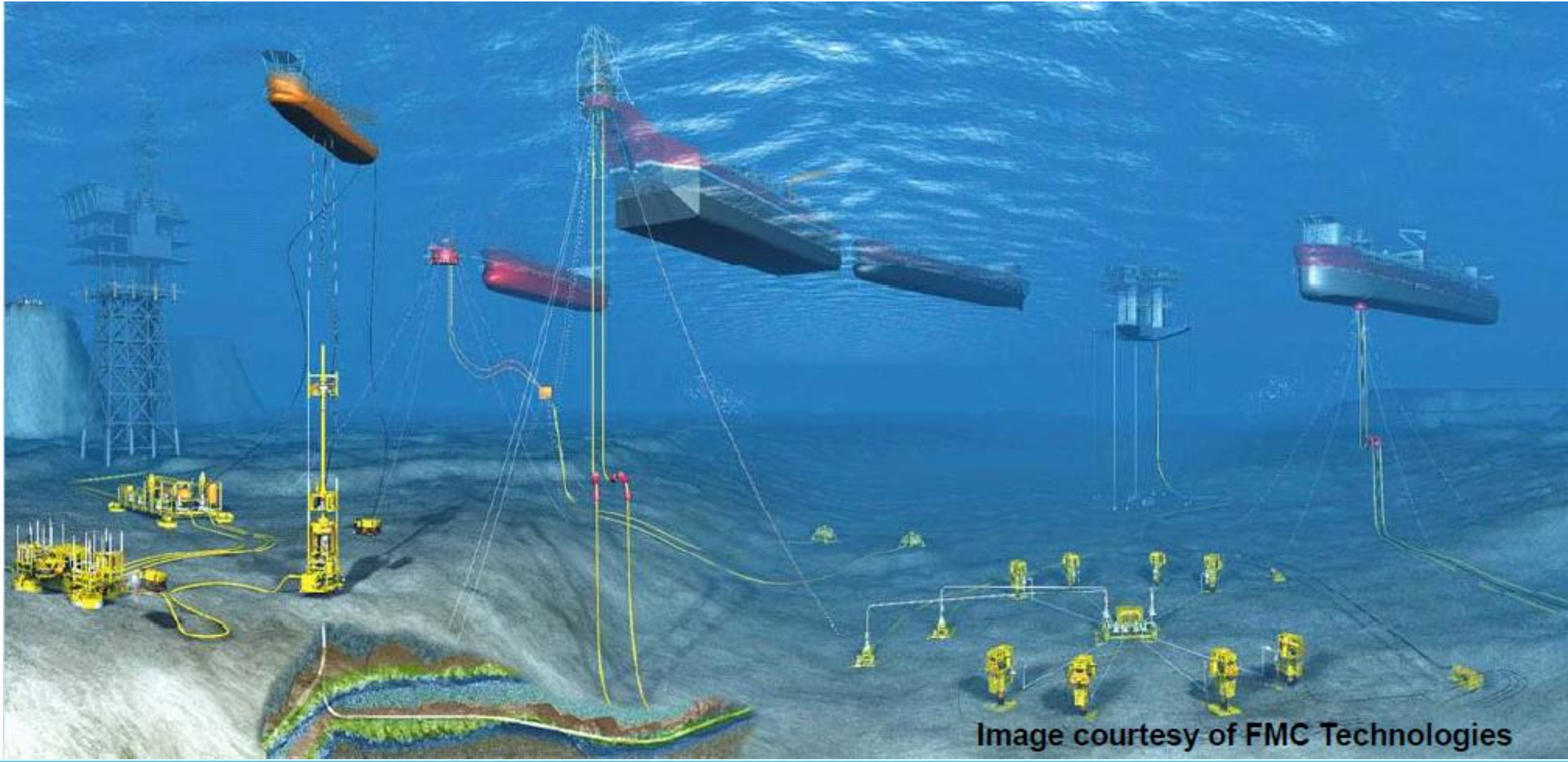


Flow Assurance

서유택

The Dynamic Three Phase Flow Simulator

9 Conservation equations

Mass (5)
Momentum (3)
Energy (1)

Mass transfer

Momentum transfer

Energy transfer

OLGA

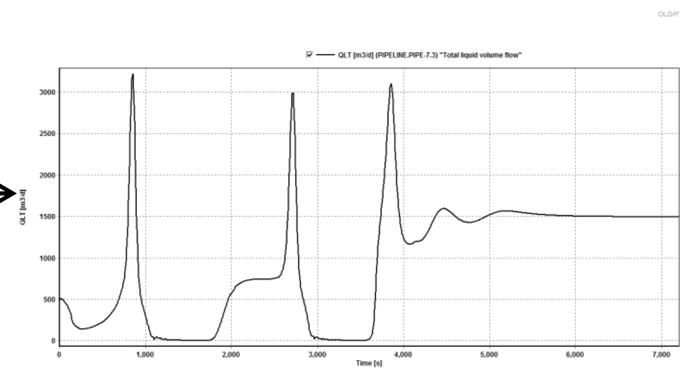
Input

Boundary and initial conditions

Pipe and process data

Fluid properties

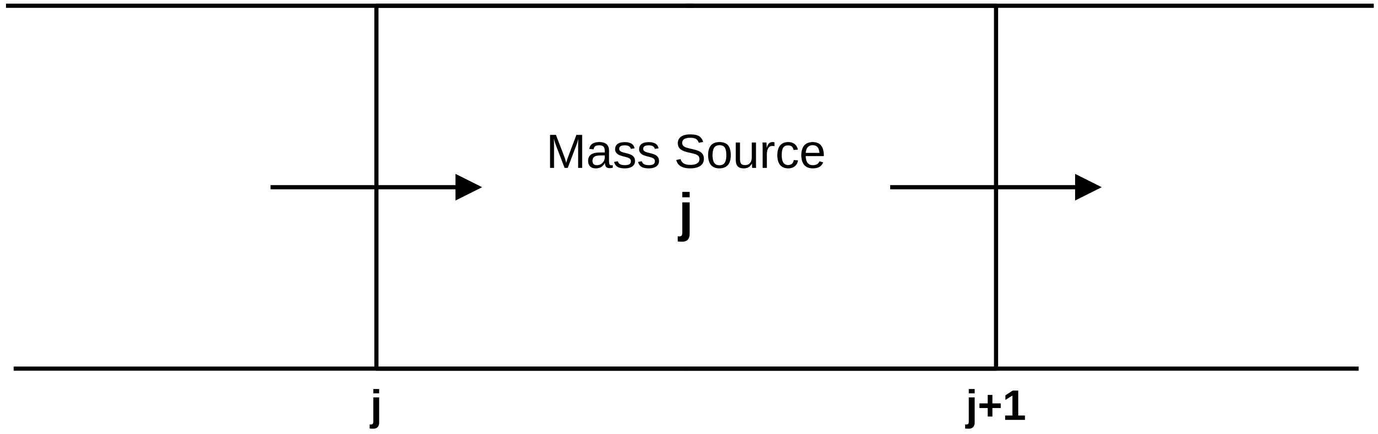
Output



The OLGA Three-phase Flow Model

- **Mass conservation**
  - Gas
  - Liquid hydrocarbon bulk
  - Hydrocarbon droplets
  - Water bulk
  - Water droplets
- **Momentum conservation**
  - Gas + droplets (oil and water)
  - Liquid hydrocarbon bulk
  - Water bulk
- **Energy conservation**
  - Mixture (only one temperature)
- **Constitutive equations**

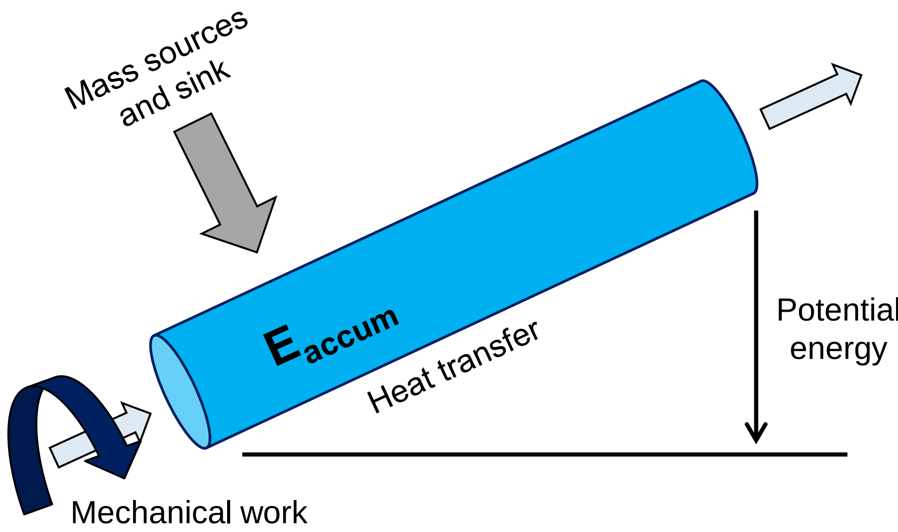
Conservation of Mass



$$\frac{\partial M_j}{\partial t} = Massflow_j - Massflow_{j+1} + Mass\ source_j$$

Conservation of Energy

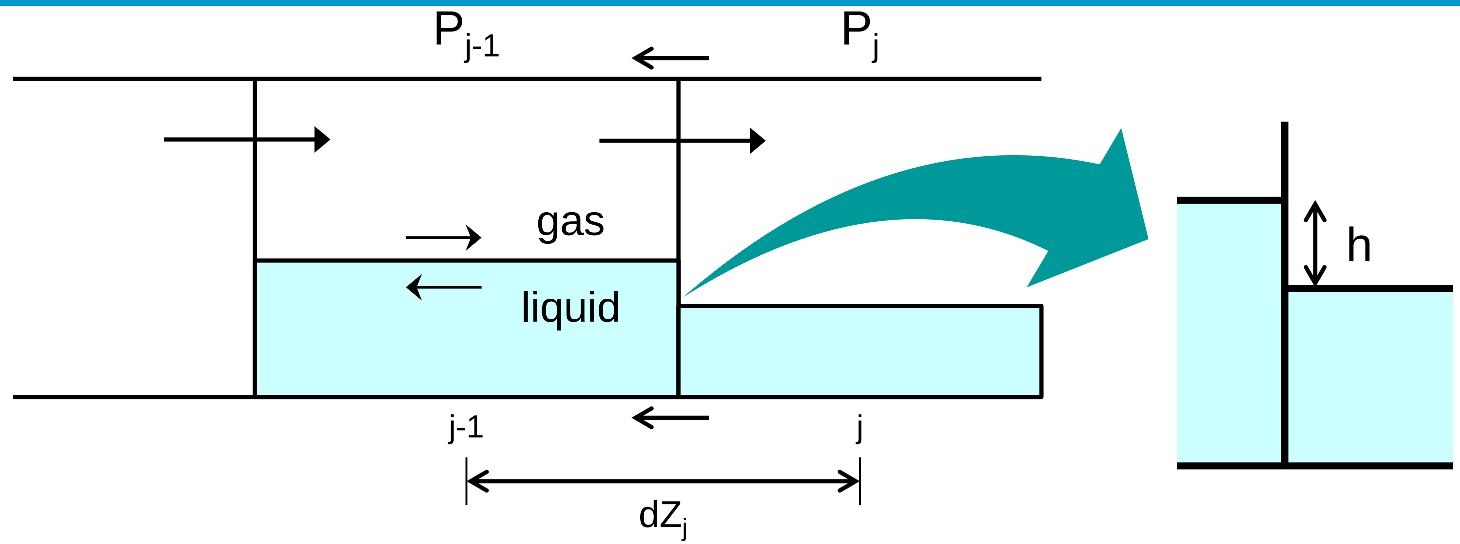
$$\frac{\partial E_j}{\partial t} = Energy\ flow_j - Energy\ flow_{j+1} + Work_j - Work_{j+1} + Energy\ source_j$$



Energy = Mass x (thermal energy + kinetic energy + potential energy)$_{spec}$

Energy flow + Work = Mass Flow x (enthalpy + kinetic energy + potential energy)

Conservation of Momentum



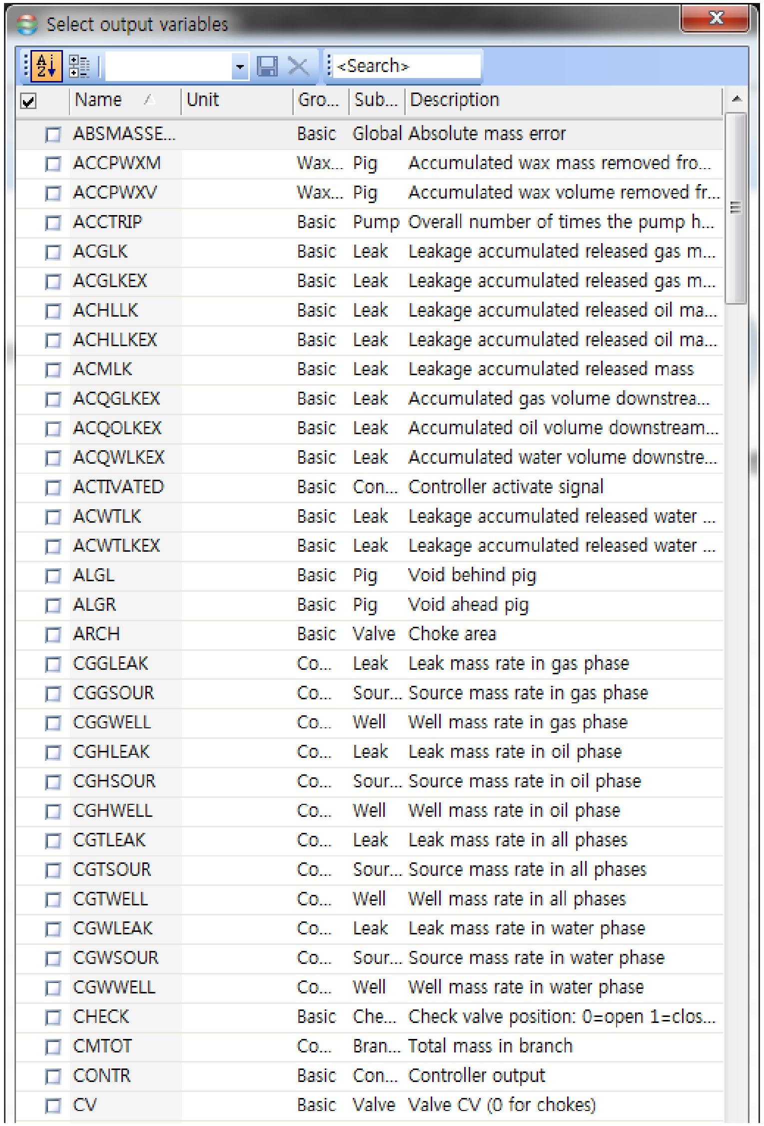
$$\frac{dM}{dt} = \frac{((M \cdot v)_{j-1} - (M \cdot v)_j)}{dZ_j} - S_j + G_j + F_{j-1} + F_j + Mt + LG$$

M = Momentum = m·v
v: Velocity
m: Mass

S = Shear = wall shear + interfacial shear
G = Gravity = m·gravity acceleration
F = Force = pressure·flow cross section
LG = Level gradient (liquid momentum only) $\sim (\rho_L - \rho_G) g \cdot h / dZ_j$
Mt = Momentum transfer = deposition - entrainment

OLGA Output

- **Primary variables**
  - 5 mass fractions (specific mass)
  - 3 velocities
  - 1 pressure
  - 1 temperature
- **Secondary variables**
  - Volume fractions
  - Flow rates
  - Fluid properties
  - etc. by the hundreds +



Select output variables

<Search>

Name	Unit	Gro...	Sub...	Description
ABSMASSE...		Basic	Global	Absolute mass error
ACCPWXM		Wax...	Pig	Accumulated wax mass removed fro...
ACCPWXV		Wax...	Pig	Accumulated wax volume removed fr...
ACCTRIP		Basic	Pump	Overall number of times the pump h...
ACGLK		Basic	Leak	Leakage accumulated released gas m...
ACGLKEX		Basic	Leak	Leakage accumulated released gas m...
ACHLLK		Basic	Leak	Leakage accumulated released oil ma...
ACHLLKEX		Basic	Leak	Leakage accumulated released oil ma...
ACMLK		Basic	Leak	Leakage accumulated released mass
ACQGLKEX		Basic	Leak	Accumulated gas volume downstrea...
ACQOLKEX		Basic	Leak	Accumulated oil volume downstream...
ACQWLKEX		Basic	Leak	Accumulated water volume downstre...
ACTIVATED		Basic	Con...	Controller activate signal
ACWTLK		Basic	Leak	Leakage accumulated released water ...
ACWTLKEX		Basic	Leak	Leakage accumulated released water ...
ALGL		Basic	Pig	Void behind pig
ALGR		Basic	Pig	Void ahead pig
ARCH		Basic	Valve	Choke area
CGGLEAK		Co...	Leak	Leak mass rate in gas phase
CGGSOUR		Co...	Sour...	Source mass rate in gas phase
CGGWELL		Co...	Well	Well mass rate in gas phase
CGHLEAK		Co...	Leak	Leak mass rate in oil phase
CGHSOUR		Co...	Sour...	Source mass rate in oil phase
CGHWELL		Co...	Well	Well mass rate in oil phase
CGTLEAK		Co...	Leak	Leak mass rate in all phases
CGTSOUR		Co...	Sour...	Source mass rate in all phases
CGTWELL		Co...	Well	Well mass rate in all phases
CGWLEAK		Co...	Leak	Leak mass rate in water phase
CGWSOUR		Co...	Sour...	Source mass rate in water phase
CGWWELL		Co...	Well	Well mass rate in water phase
CHECK		Basic	Che...	Check valve position: 0=open 1=clos...
CMTOT		Co...	Bran...	Total mass in branch
CONTR		Basic	Con...	Controller output
CV		Basic	Valve	Valve CV (0 for chokes)

Most common output variables

Variables	
PT	Local pressure in fluid
TM	Local fluid temperature
HOL	Local total liquid volume fraction
QG	Gas flow rate
QLT	Total liquid flow rate
ID	Flow pattern identifier
UG	Gas velocity
UL	Total liquid velocity
EVR	Erosional velocity ratio (When EVR>1, the API 14 max velocity is violated.)

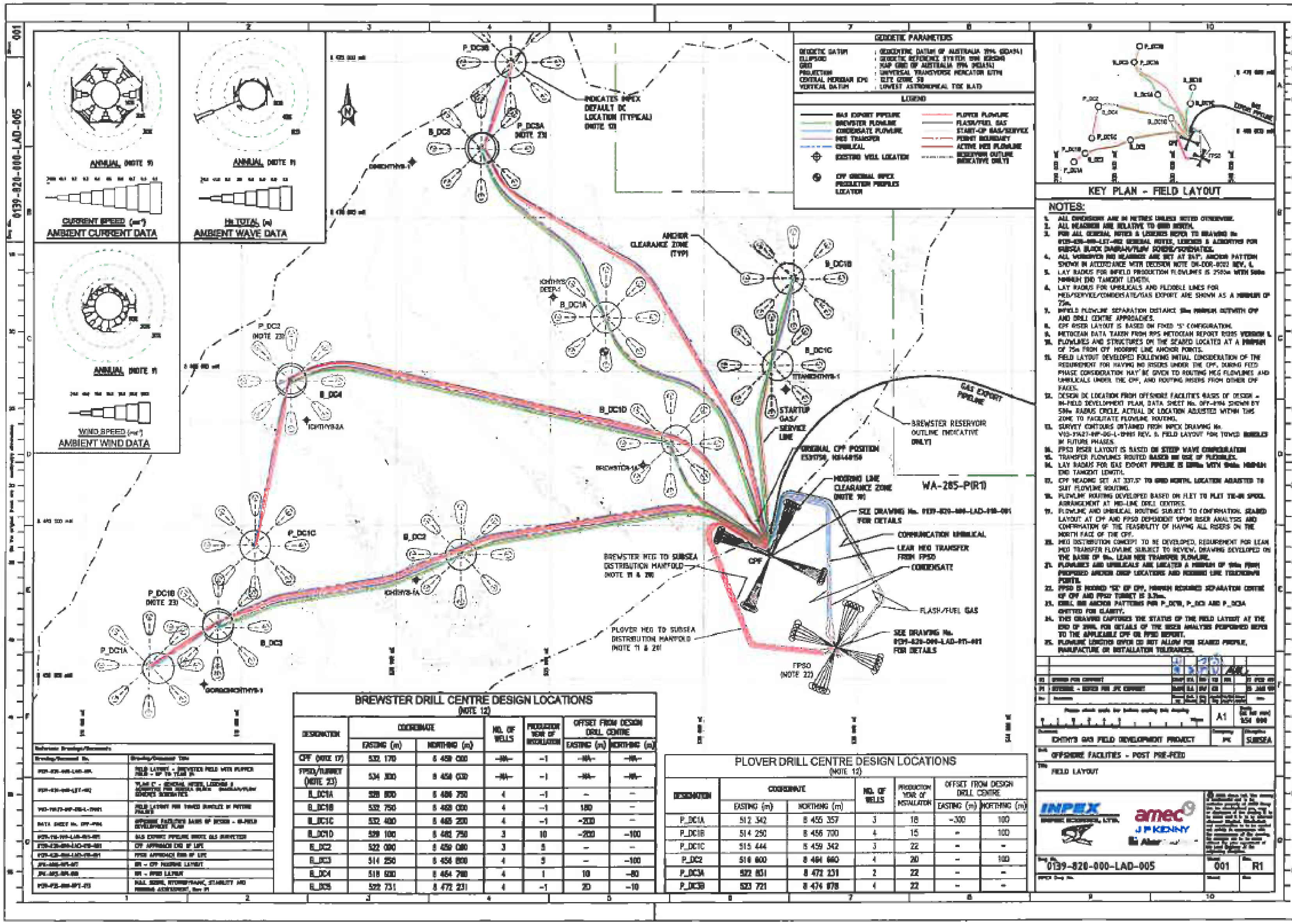
1: Stratified flow

2: Annular flow

3: Slug flow

4: Bubbly flow

Ex 1. Multiphase flow analysis in Ichthys field



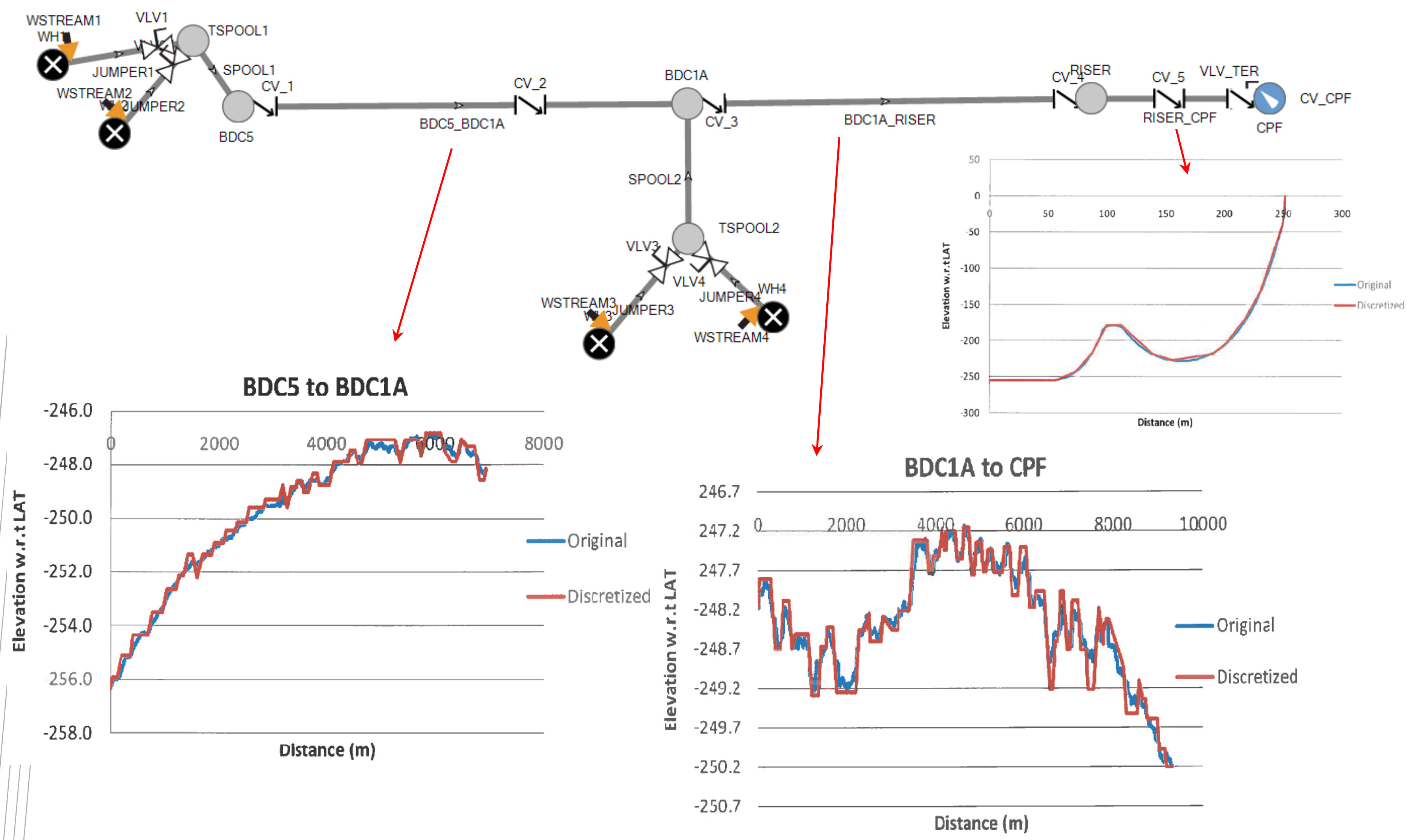
BREWSTER DRILL CENTRE DESIGN LOCATIONS (NOTE 12)

DESIGNATION	COORDINATE EASTING (m)	COORDINATE NORTHING (m)	NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE EASTING (m)	OFFSET FROM DESIGN DRILL CENTRE NORTHING (m)
CPF (NOTE 17)	532 170	8 459 000	-NA-	-1	-NA-	-NA-
FPSO/TURRET (NOTE 23)	534 300	8 454 030	-NA-	-1	-NA-	-NA-
B_DC1A	528 800	8 486 750	4	-1	-	-
B_DC1B	532 750	8 469 000	4	-1	180	-
B_DC1C	532 400	8 465 200	4	-1	-200	-
B_DC1D	529 100	8 482 750	3	10	-200	-100
B_DC2	522 000	8 459 000	3	5	-	-
B_DC3	514 250	8 456 800	4	3	-	-100
B_DC4	518 600	8 464 700	4	1	10	-80
B_DC5	522 731	8 472 231	4	-1	20	-10

PLOVER DRILL CENTRE DESIGN LOCATIONS (NOTE 12)

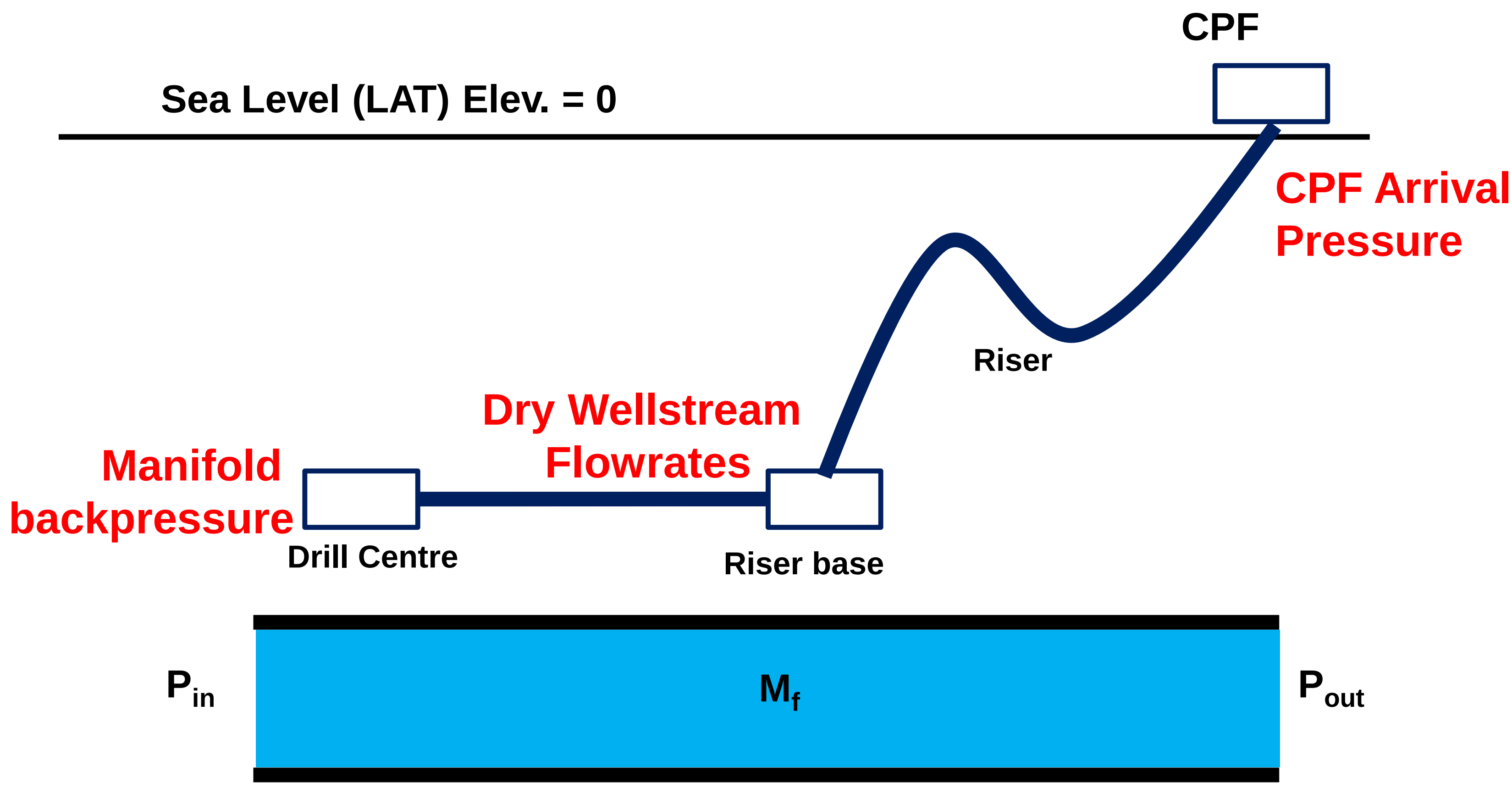
DESIGNATION	COORDINATE EASTING (m)	COORDINATE NORTHING (m)	NO. OF WELLS	PRODUCTION YEAR OF INSTALLATION	OFFSET FROM DESIGN DRILL CENTRE EASTING (m)	OFFSET FROM DESIGN DRILL CENTRE NORTHING (m)
P_DC1A	512 342	8 455 357	3	18	-300	100
P_DC1B	514 250	8 456 700	4	15	-	100
P_DC1C	515 444	8 459 342	3	22	-	-
P_DC2	516 600	8 464 660	4	20	-	100
P_DC3A	522 831	8 472 231	2	22	-	-
P_DC3B	523 721	8 474 878	4	22	-	-

Simulation with OLGA – BDC5 to CPF



OLGA simulation basis

- Among two of P_{in} (Inlet pressure), M_F (Flowrate) , P_{out} (Outlet pressure) were given, other unknown can be calculated.
- For offshore fields, P_{in} = Manifold backpressure, M_F = Dry Wellstream Flowrate, P_{out} = CPF Arrival pressure.



Simulation matrix for subsea flowline sizing

i) Manifold backpressure estimation

: generate manifold backpressure vs. flowrate plots

: backpressure at any manifold for any possible combination of flowrates can be interpolated and estimated.

ii) Surge volume estimation

: The worst surge volume case can be identified from the simulation at corresponding cases with different flowline ID. (16”, 18”, 20”)

: Find out the maximum possible reduction or increase in surge volumes arriving at topside (slug catcher design).

iii) Minimum turn-down rates

: The minimum turndown limit for the desired flowline will be determined based on hydrate and wax deposition analysis.

: Impact of line sizing on minimum turndown limits based on solid deposition constraint.

: Investigation of the impact of line sizing on minimum achievable turn-down rates based on slugging tendency will be performed.

Slug flow characterization in the pipeline

- During the turndown and ramp up stages, the <u>maximum surge volume</u> and <u>slug frequency</u> will be investigated to safe operate the subsea production system and topside processes.

- Along with the <u>arrival flowrate</u> analysis, maximum <u>arrival temperature and pressure</u> will be obtained through the simulation cases, which will be an input to topside heat and mass balance analysis.

  (There may be a restriction on the riser design temperature depending on the riser materials)

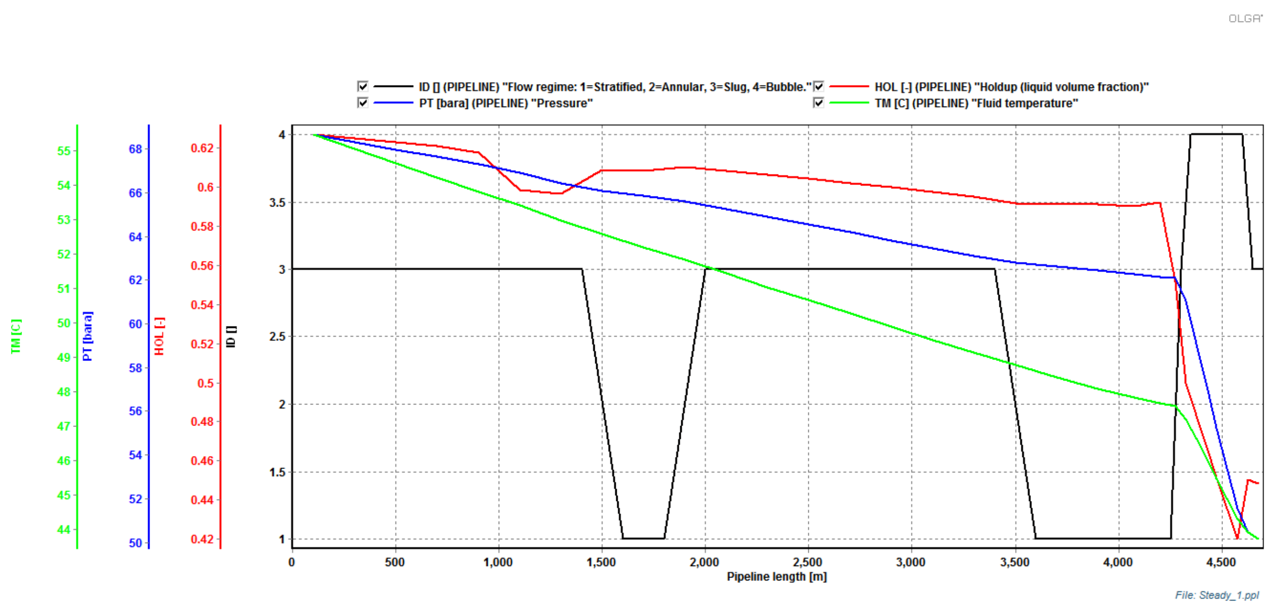
- Subsea production system will be the same as the model used for back pressure estimation, and the riser model will incorporates the section from the static section of the production riser to the platform.

Simulation of offshore gas production system

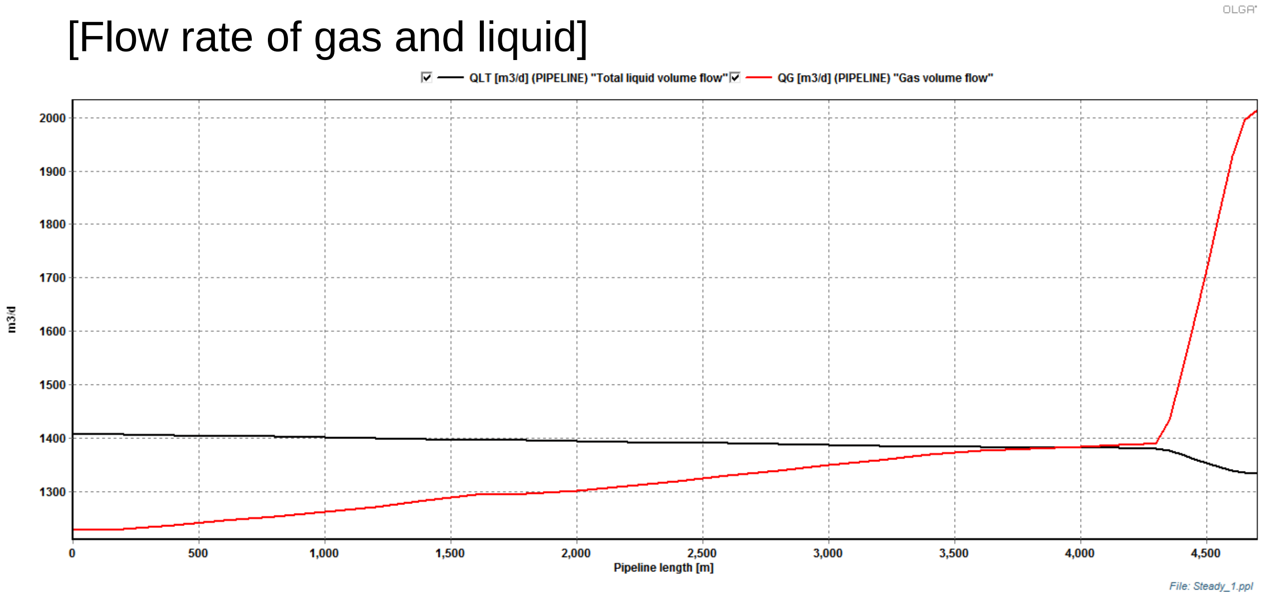
- Steady-state analysis results

  : The liquid hold up was less than 0.6 and the flow regime became slug flow in the riser section. (1-stratified flow, 2-annular flow, 3-hydrodynamic slug flow, 4-bubble flow.)

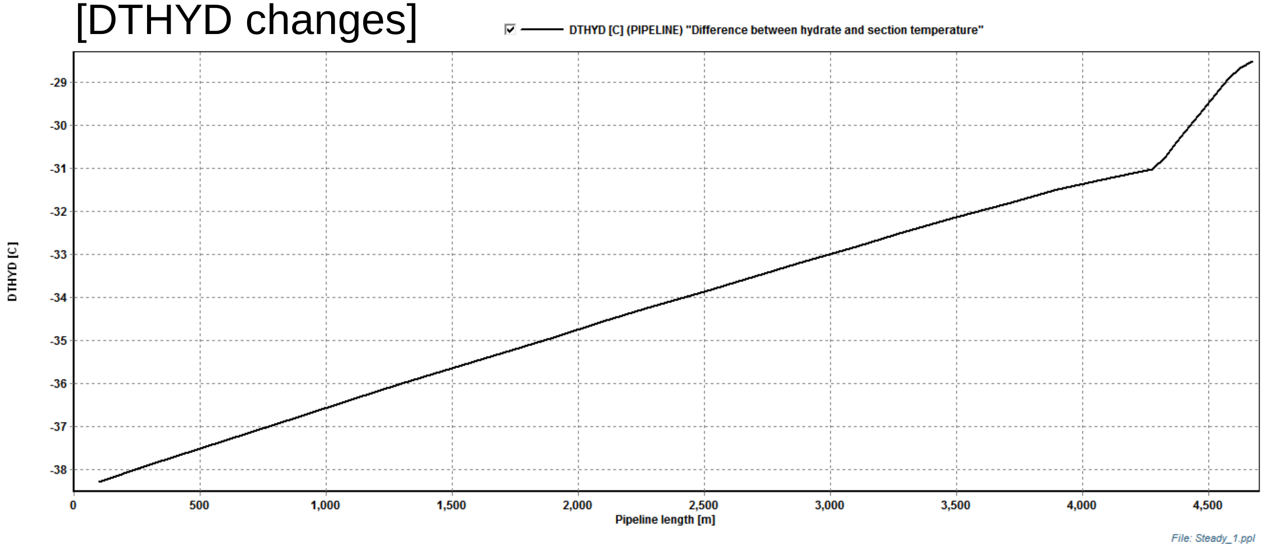
  : The arrival pressure was 50 bar and the temperature was 44 ^{o}C in this system layout.



[Flow rate of gas and liquid]



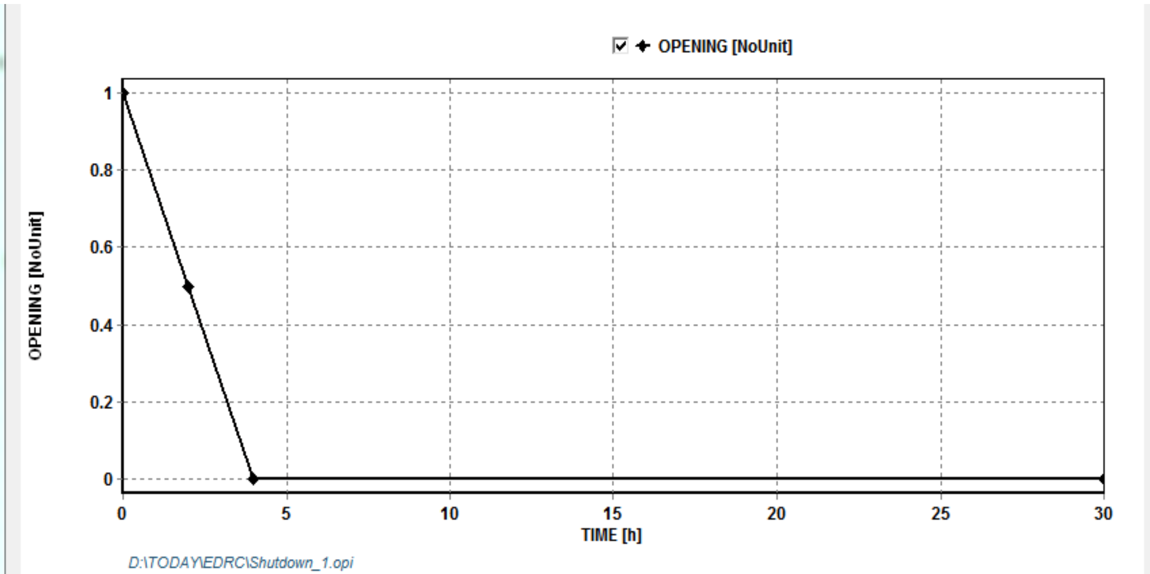
[DTHYD changes]



- Shut down operation

  : It is possible to set the rate at which the valve closes using the time scheduling function on the OLGA valve component. Here the valve closing rate is 25 %/hr.

  : The valve closing rate is depends on the operating company

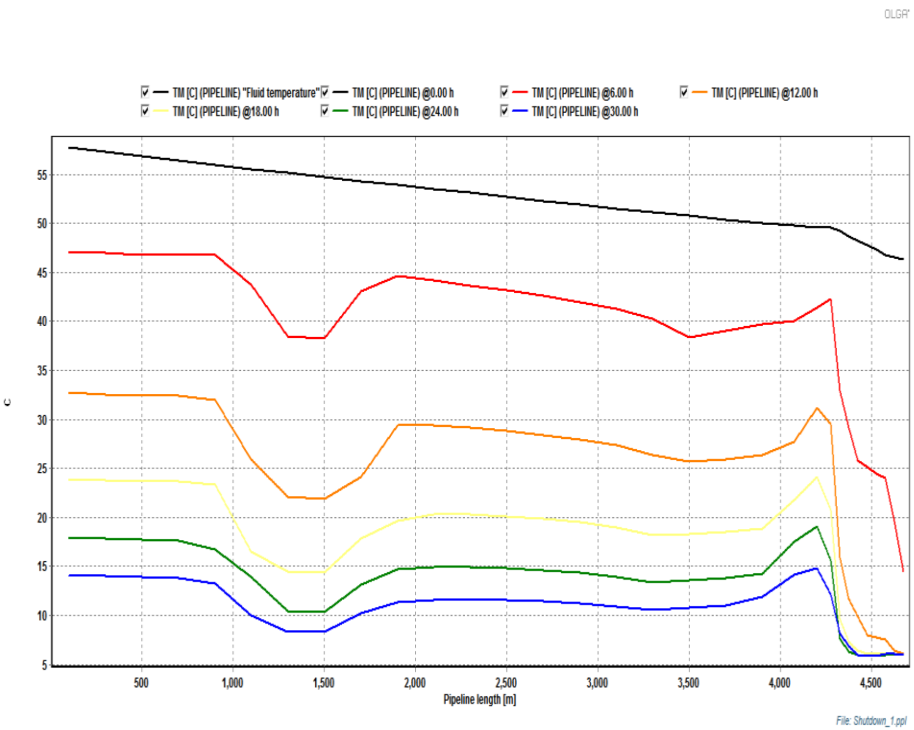


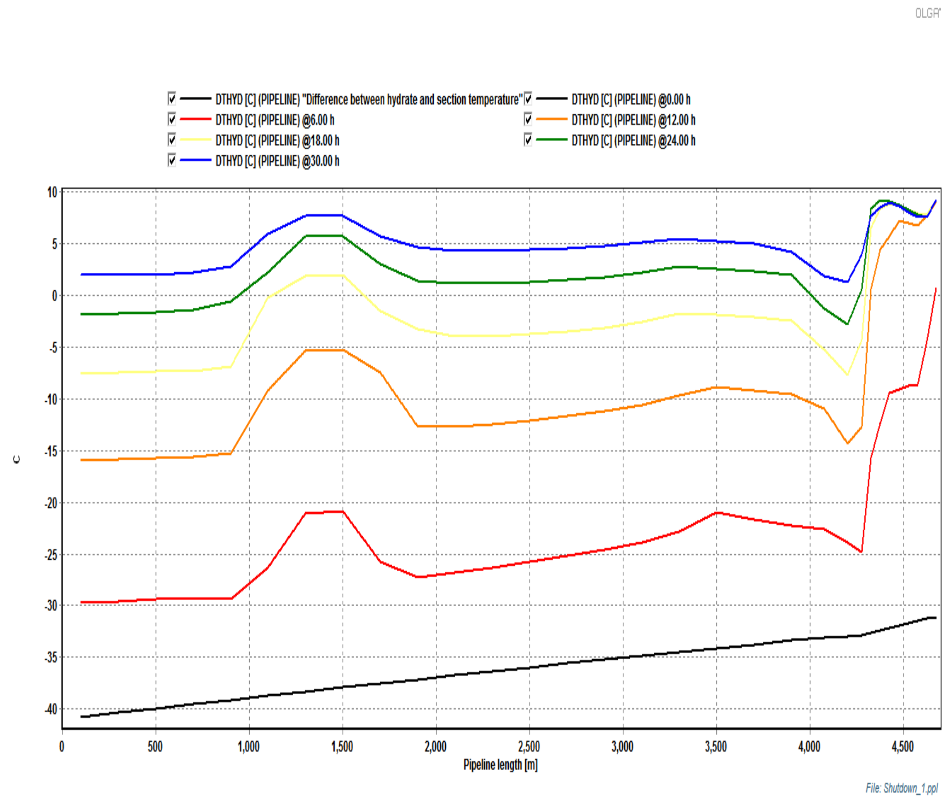
TIME	h	0	2	4	30				
OPENING	NoUnit	1	0.5	0	0				

- Temperature profiles during shutdown

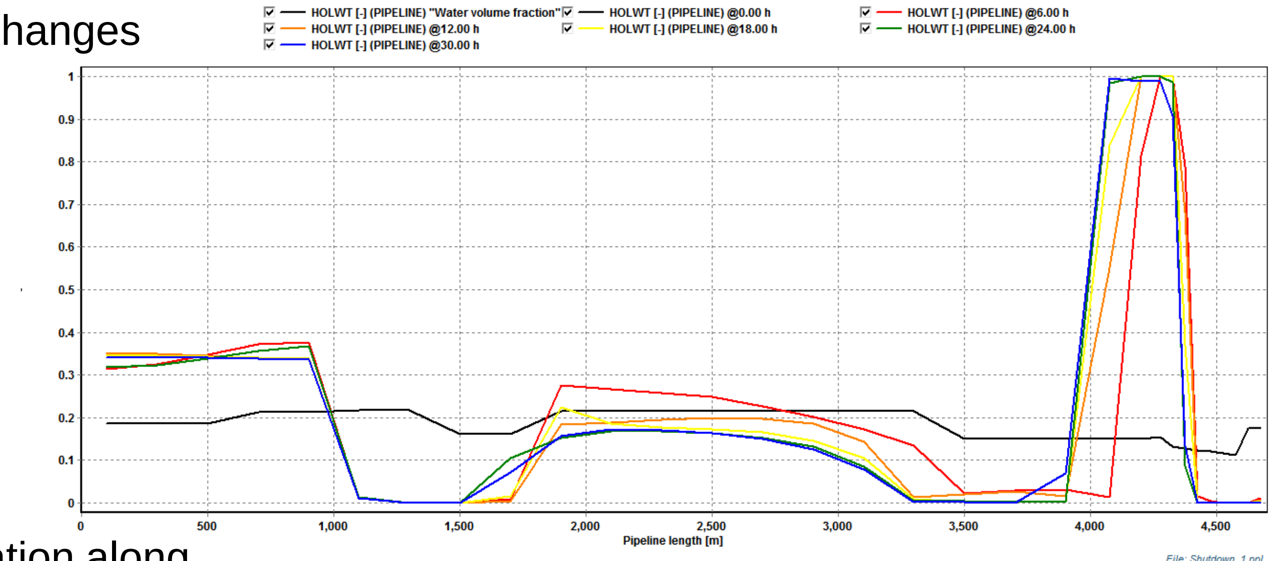
  : Closing the valve allows heat transfer between fluid and seawater, and the temperature drops. The degree of temperature drop varies due to different specific heats of gas and liquid, and different liquid holdups at different sections in the pipeline geometry.

  : Cool down time is the time take for hydrates to form in the pipeline after shutdown operation. In the figure below, DTHYD exceeds 0°C 12 hours after shutdown, so the cool down time is 12 hours.

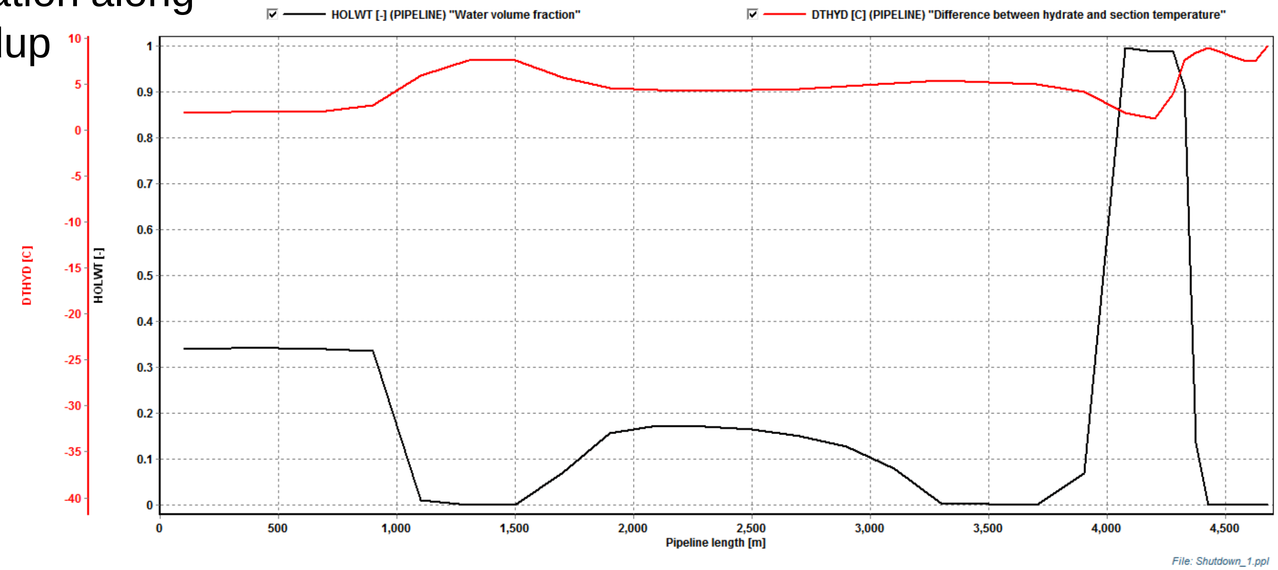




- Liquid holdup changes

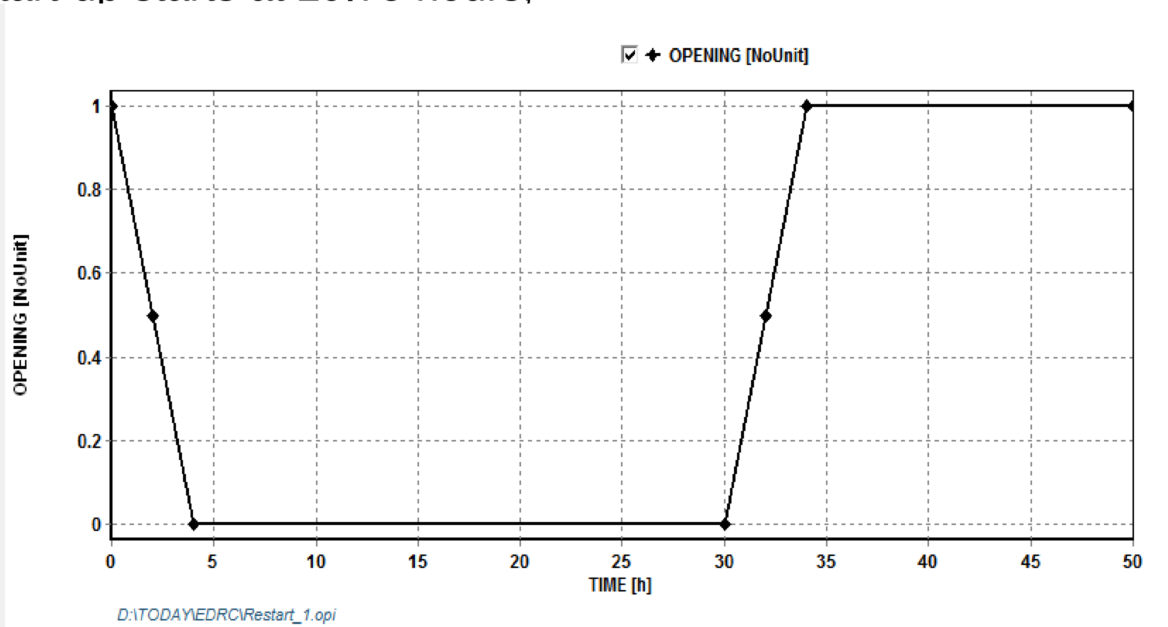


- DTHYD calculation along with water holdup



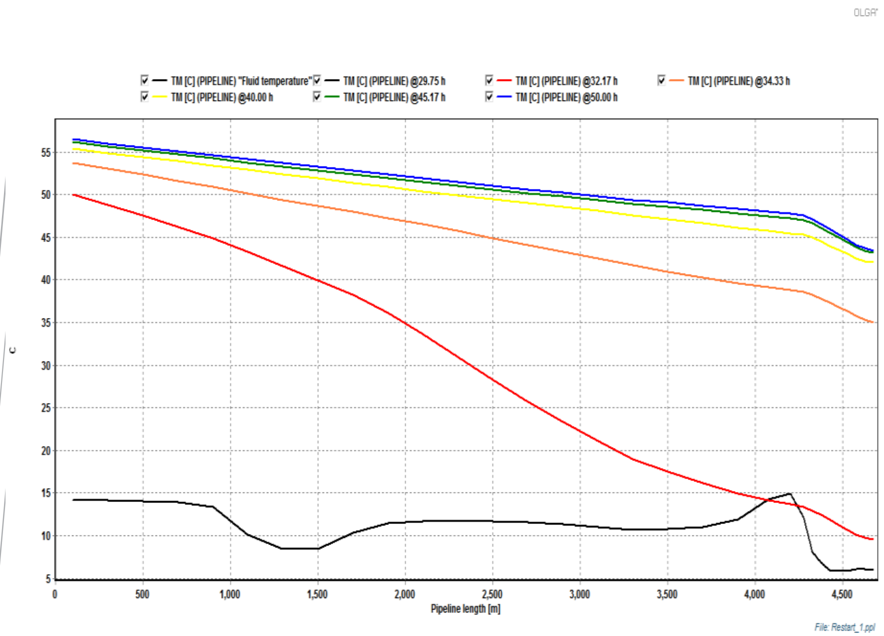
Start up operation for surge volume estimation

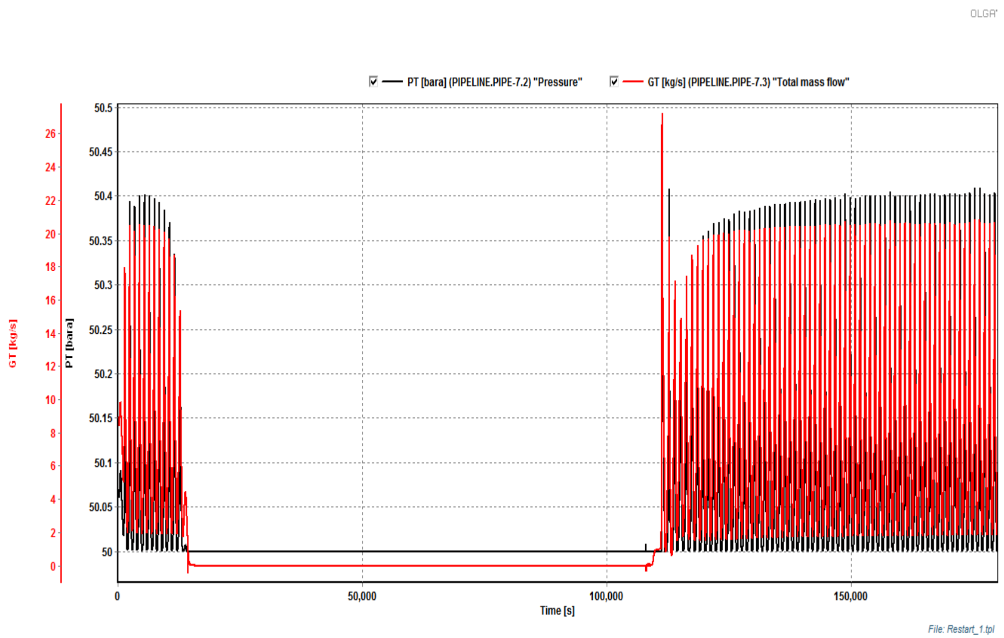
- Topside choke valve and subsea choke valve must be opened during the startup operating simulation. Valve opening ratio can be adjusted using the time scheduling function on the valve component of OLGA.
- The start-up starts at 29.75 hours,



TIME	h	0	2	4	30	32	34	50
OPENING	NoUnit	1	0.5	0	0	0.5	1	1

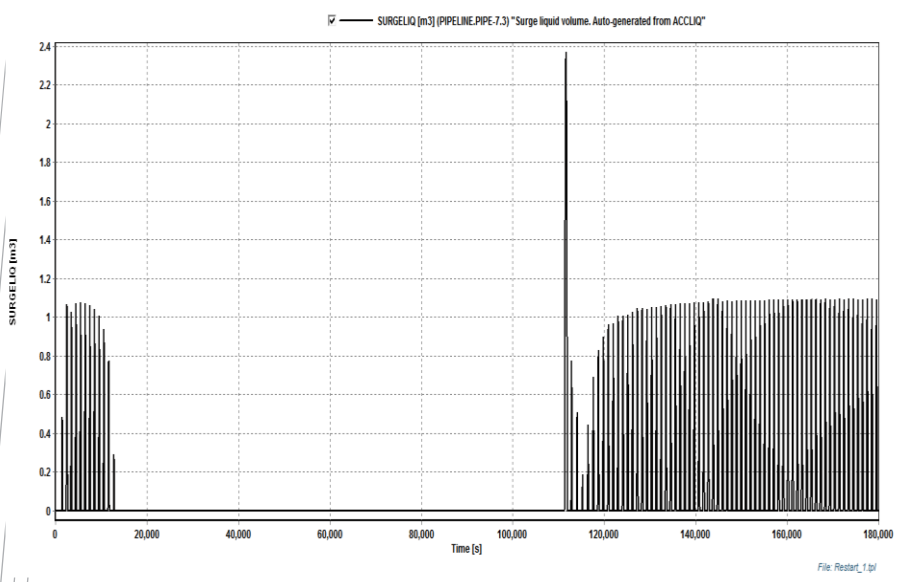
- Cooled fluid in the pipeline and hotter fluid in the reservoir are mixed and flow into topside while the temperature gradually increases.
- During the startup operation; arrival pressure at topside, flow rate, and flow pattern are used for flow stability analysis.
- The graph below shows a very unstable flow of the topside fluid at startup. Oscillation is severe in the ranges: 50 – 50.5 bars pressure, 0 – 26kg/s flow rate.

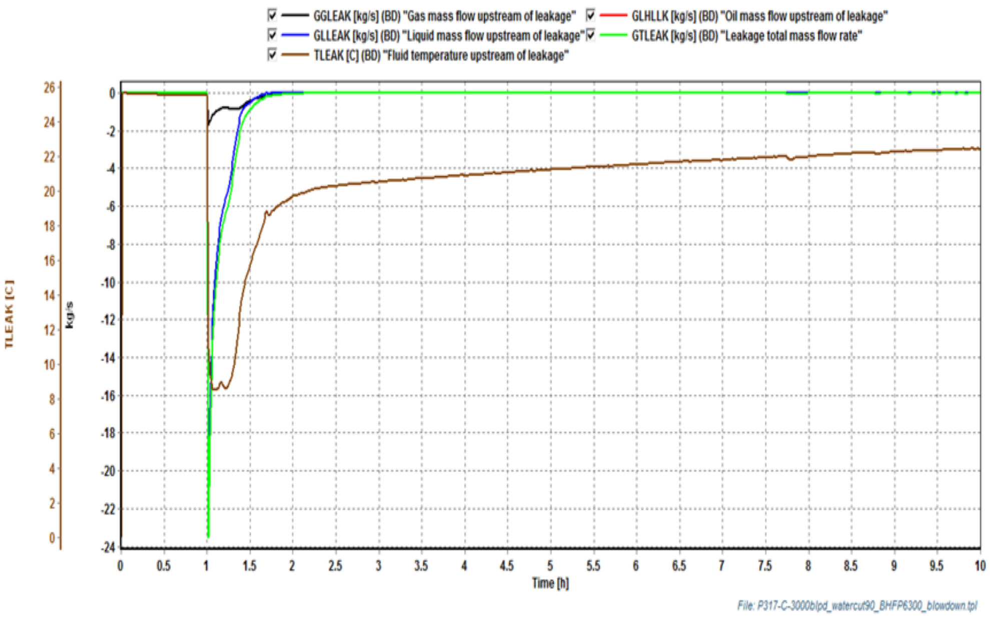




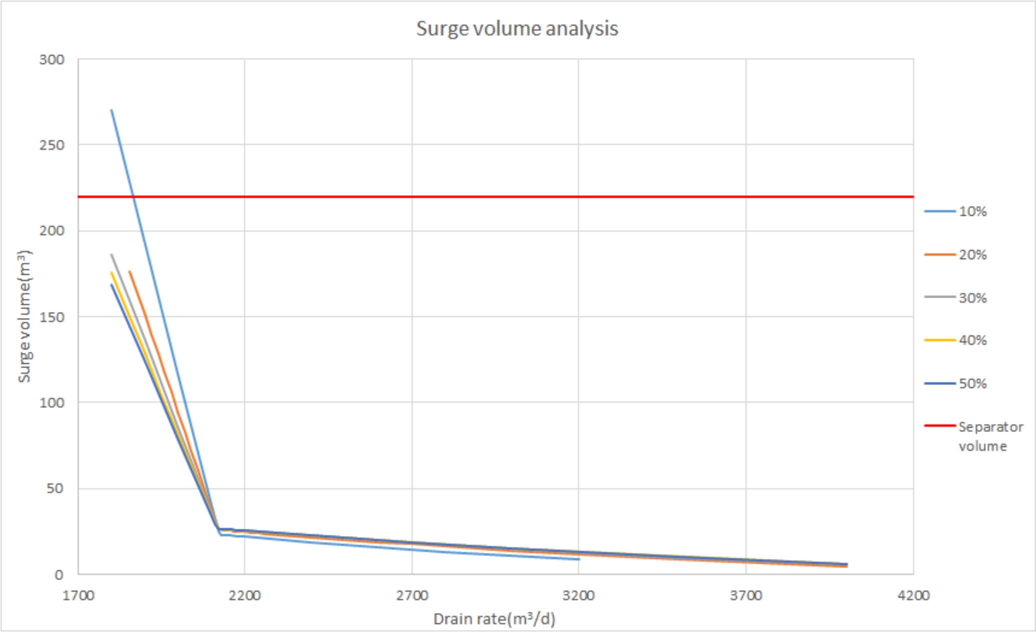
Surge analysis and Depressurization

- Accumulated fluid flows into topside if start up operation takes place after an extended shutdown, and this may cause a failure in the surge tank.
- So drain rate and maximum surge volume over restart time should be calculated from surge analysis, and employ these values in determining the surge tank size and surge tank operation methods.
- If depressurization occurs, the flow rate of exposed fluid falls sharply due to the J-T effect. This not only increases the likelihood of hydrate formation, but also affects the hardness of a material, so the operation conditions should be thoroughly understood.



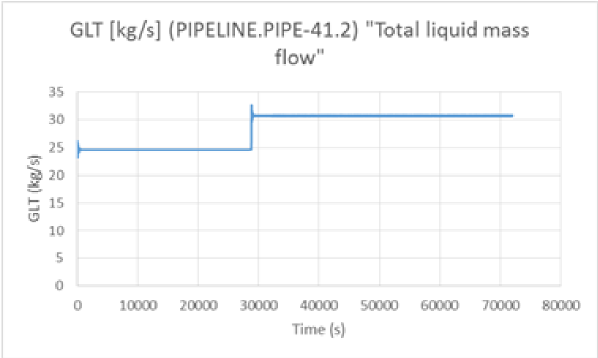


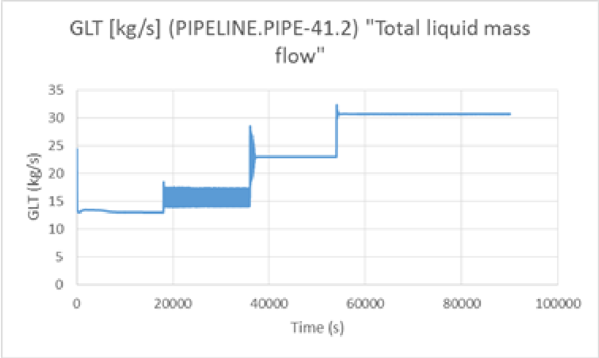
- During startup operation, or ramp-up operation simulation; run surge analysis to determine the surge tank size and organize operation philosophy.
- The graph below shows the relationship between drain rate and maximum surge volume when valve openings were varied.
- Assuming that the separator volume is approximately 210m^3, surge tank failure does not occur when the valve opening is set at 20, 30, 40, and 50%. Though, the drain rate must be maintained at 2,000m^3/d or higher when the valve opening is 10%.

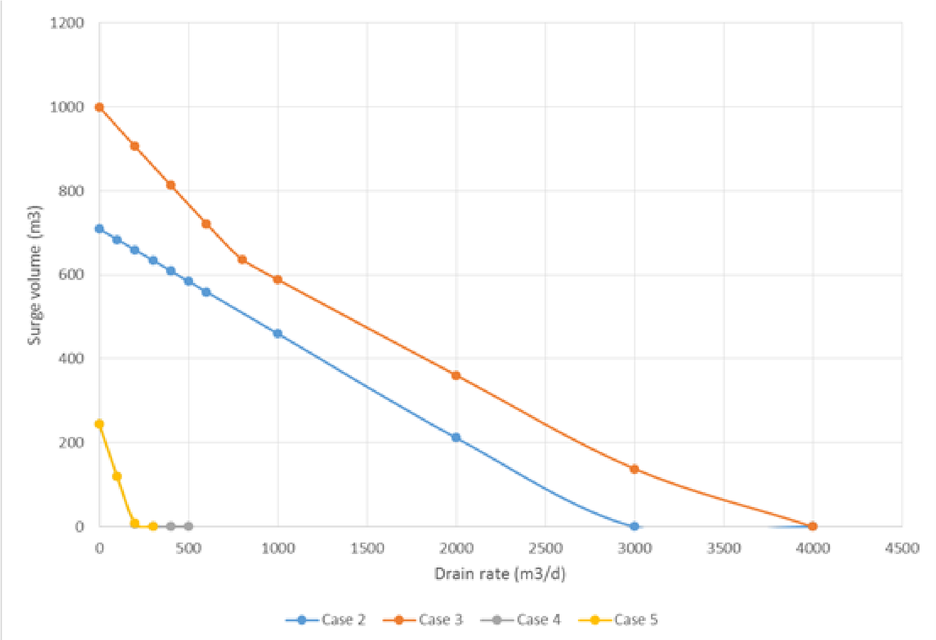


Ramp up analysis

- Increase the production rate may cause unstable flow. Surge analysis should be carried out to prevent surge tank failure.
- Assume the pipeline at the topside arrival as surge tank, and calculate the maximum surge volume as the drain rate is varied. Plot a graph with drain rate on the x-axis, and maximum surge volume on the y-axis; and use it to determine the surge tank size.

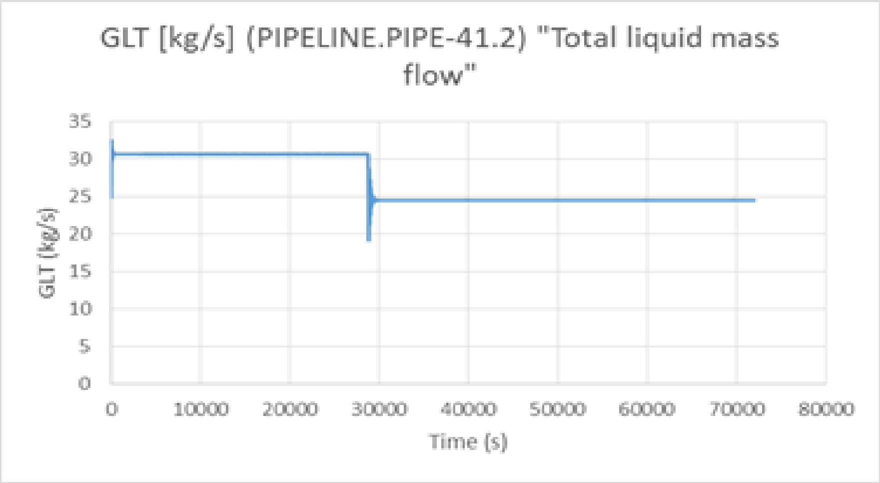


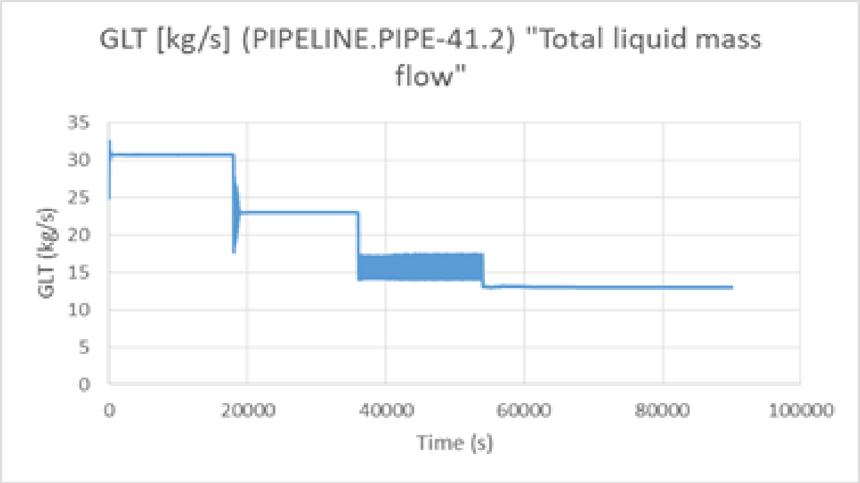




Turn down operation

- The turn-down operation is reducing flow rate to a certain rate by turn-down and stop the field before shutdown operation starts.
- To calculate the minimum slug free flow rate, reduce the flow rate in steps by observing the flow rate and pressure of the fluid that enters the topside – in other words, the flow stability.
- If fluid in a pipeline flows at a steady-state, the flow rate at which the fluid enters the topside is constant as shown on the left graph. If not, the flow rate at which the fluid enters the topside is shaky as shown on the right graph.

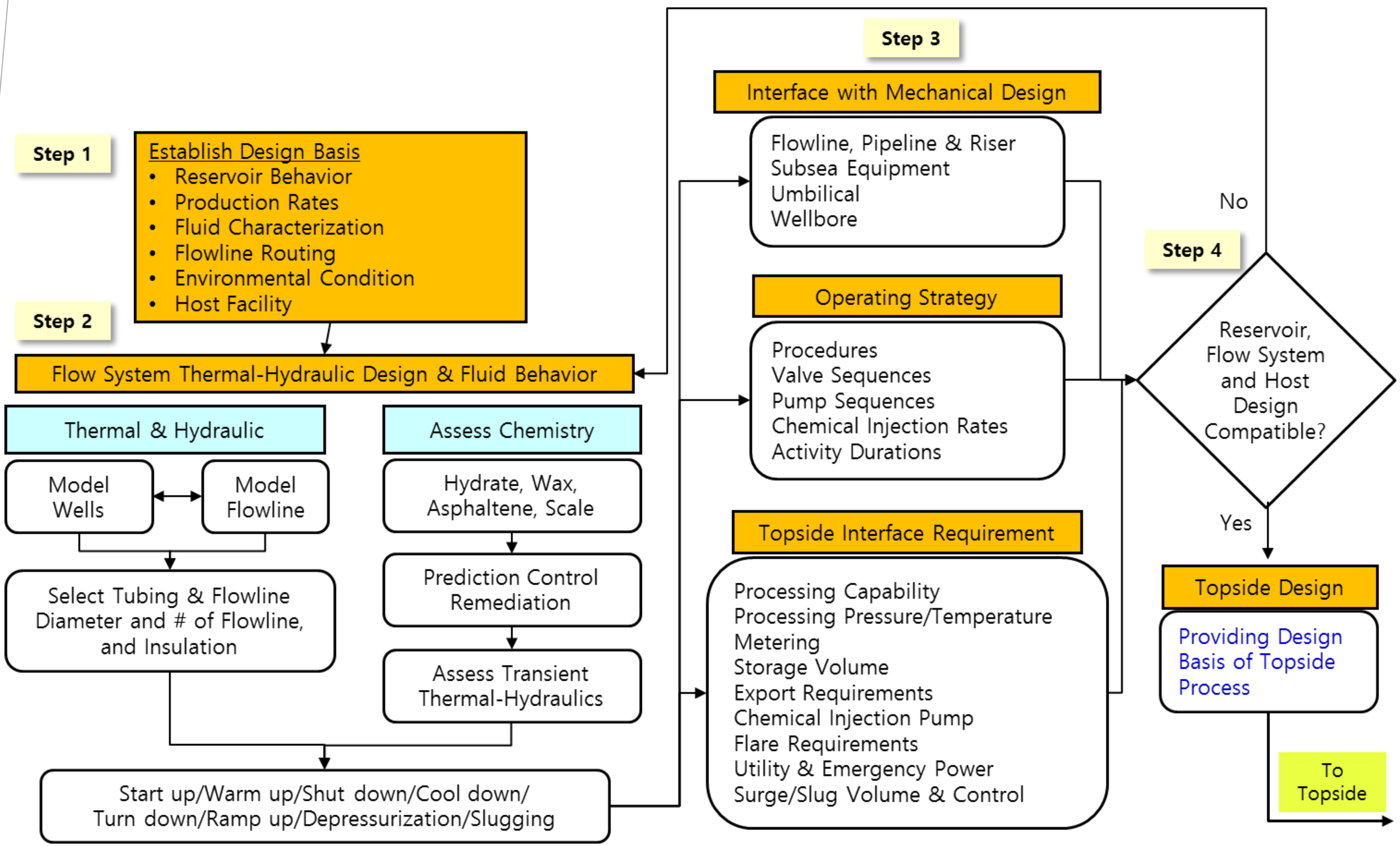




Applications of transient simulations

- The results from transient multiphase flow simulations include:
  : Slug flow modelling
  : Estimates of the potential for terrain slugging
  : Pigging simulation
  : Identification of area with higher corrosion potential, such as water accumulation in low spots in the line and area with highly turbulent/slug flow
  : Start-up, shut-down, and pipeline depressurization simulations
  : Slug catcher design
  : Development of operating guidelines
  : Real time modeling of production scenarios
  : Design of control systems for downstream equipment
  : Operator training

Evaluation of offshore flowline design



Stage 1. Review and finalize design basis

1. Generally, the system is assumed to comprise of flowlines, risers, umbilicals, wellbore, jumpers, manifolds, PLETs, and CPFs.
2. Fluid product obtained from a reservoir is transported to CPF via wellbores, flowlines, and risers. Various chemicals and electricity are transferred from CPF to the subsea through umbilicals.
3. The following input resources are required to run a simulation based on the system explained above:
   : Field scheme (platform type, size and location of equipment)
   : Reservoir compositions, pipeline property (pipeline geometry, pipeline diameter / material / thickness, insulation material / thickness)
   : Environmental conditions (air temperature / velocity, water temperature / velocity)
   : Boundary conditions (reservoir conditions, topside arrival conditions)
4. Fluid characterization should be included in this step, and relevant materials are described in Note 1.

Stage 2. Thermodynamic design and fluid behavior

- Steady-state analysis
    1. Carry out a thermal & hydraulics analysis by using steady-state simulation to obtain fluid temperature, pressure, flow rate, flow velocity, and liquid hold up profile of the pipeline fluid.
    2. Calculate inner diameter of the pipeline using the results.
    3. Determine specifications for a pump or a compressor for use in topside or subsea.

- Shutdown analysis
    1. Carry out a ramp down analysis prior to the shutdown simulation to obtain the minimum slug free flow rate. Plan a ramp down scenario accordingly, and then proceed.
    2. Locate potential regions for hydrate formation using DTHYD in order to analyze the hydrate risk using the shutdown simulation. Assume cool down time as the time span when the temperature is above 0°C on DTHYD. Find the temperature region where hydrate formation is at high risk by observing the water hold up, simultaneously.
    3. WAT (Was Arrival Temperature) is used to check whether or not wax deposition has taken place. It is possible to calculate the time taken for fluid to reach the gel point or WAT during the shutdown operation.
    4. If dead oil displacement carried out, it is possible to calculate the dead oil volume and injection pressure.

- Start-up analysis
    1. Analyze the flow regime by carrying out thermal & hydraulic analysis and identify whether slugging occurs or not. Calculate maximum surge volume by surge analysis and determine the size of surge tanks.
    2. In case of a cold restart, warm-up time can be calculated. Warm-up time is when the temperature is below 0°C on DTHYD. Additional 3°C on DTHYD can be regarded as an engineering margin. Figure out the amount of hydrate inhibitor based on the warm-up time obtained.
    3. Be cautious of hydrate, wax, or any other solid deposition during the cold restart.
    4. Keep an eye out for the DTHYD variables during OLGA simulation.

- Pigging analysis
    1. Both mechanical pigging and injection of chemical inhibitors are required in removing pipeline debris.
    2. Estimate the amount of accumulated wax for effective pigging operation. Calculate the pigging frequency using this. Calculate the outlet pressure while pigging, and predict the flow regime of the pipeline and its maximum surge volume.
    3. Note the following variables during OLGA simulation: ID (flow regime), SURGELIQ (surge liquid volume).

- Depressurization of flowlines

  : If depressurization occurs between shutdown and startup, it is possible to calculate the maximum liquid / gas rate, minimum temperate, depressurization time during the blow down by depressurization analysis.

- Remediation strategy set-up

  : An appropriate remediation method – characterized by each fields – is needed in the event of hydrate, wax, or any other solid depositions. Refer to ***Note 2*** for detailed remediation management strategies. Information related to hydrates is shown in ***Note 3***.

- Corrosion / erosion analysis

  : Corrosion can occur inside or outside the pipeline. Internal carrion can be divided into sweet and sour corrosion according to the differing composition of CO_2 and H_2S.

- Sand deposition analysis

  : Sand flowing in from the reservoir causes erosion and this directly affects the production rate. It is possible to lengthen lifetime of field production and ensure stable production by an appropriate sand management.

- Stage 3

  : Based on the obtained thermal/hydraulic analysis results in stage 2, the design of offshore and topside production systems can be performed using the company's internal design guideline

  : Line sizing – flowline, riser, jumper, spool, umbilical.

  : Vessel sizing – slug catcher, separator, reflux drum, gas and oil processing units, condensate storage tank, inhibitor storage tank.

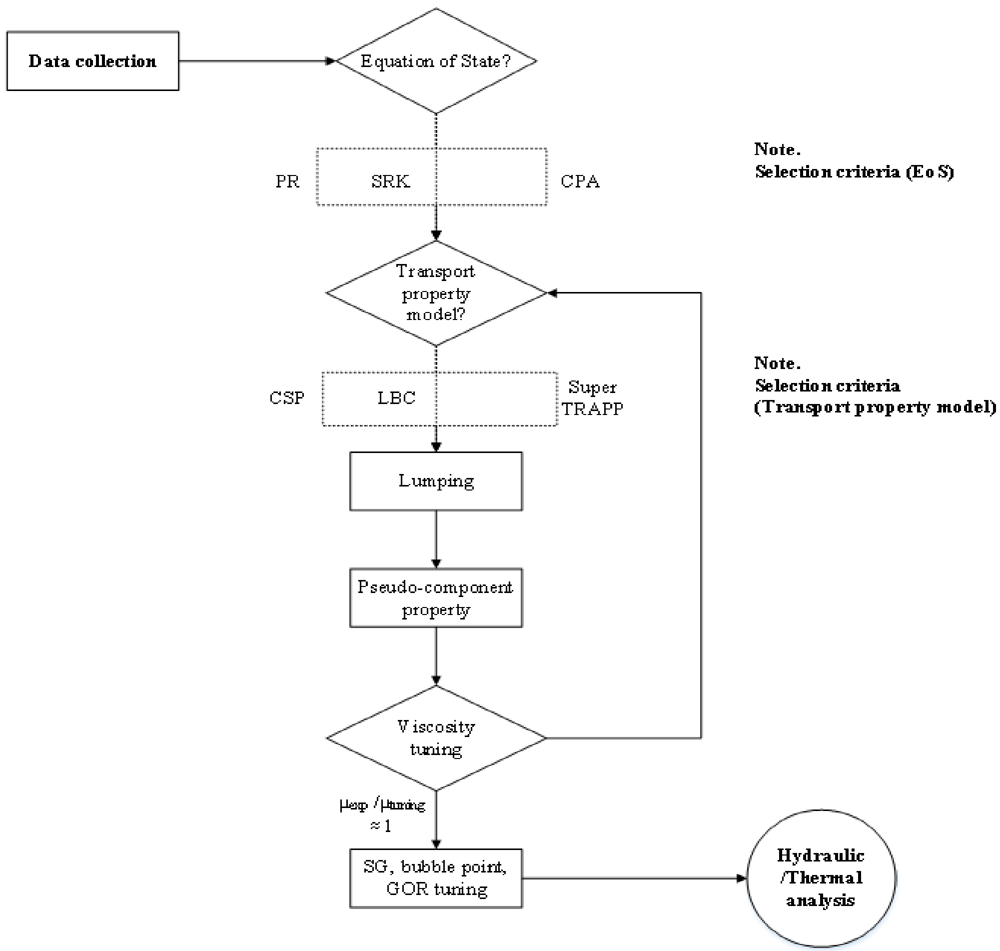
  : Pressure rating – pressure safety valves, pumps, compressors

  : Operation philosophy – valve opening/closing, pump sequences for injection and export, chemical injection,

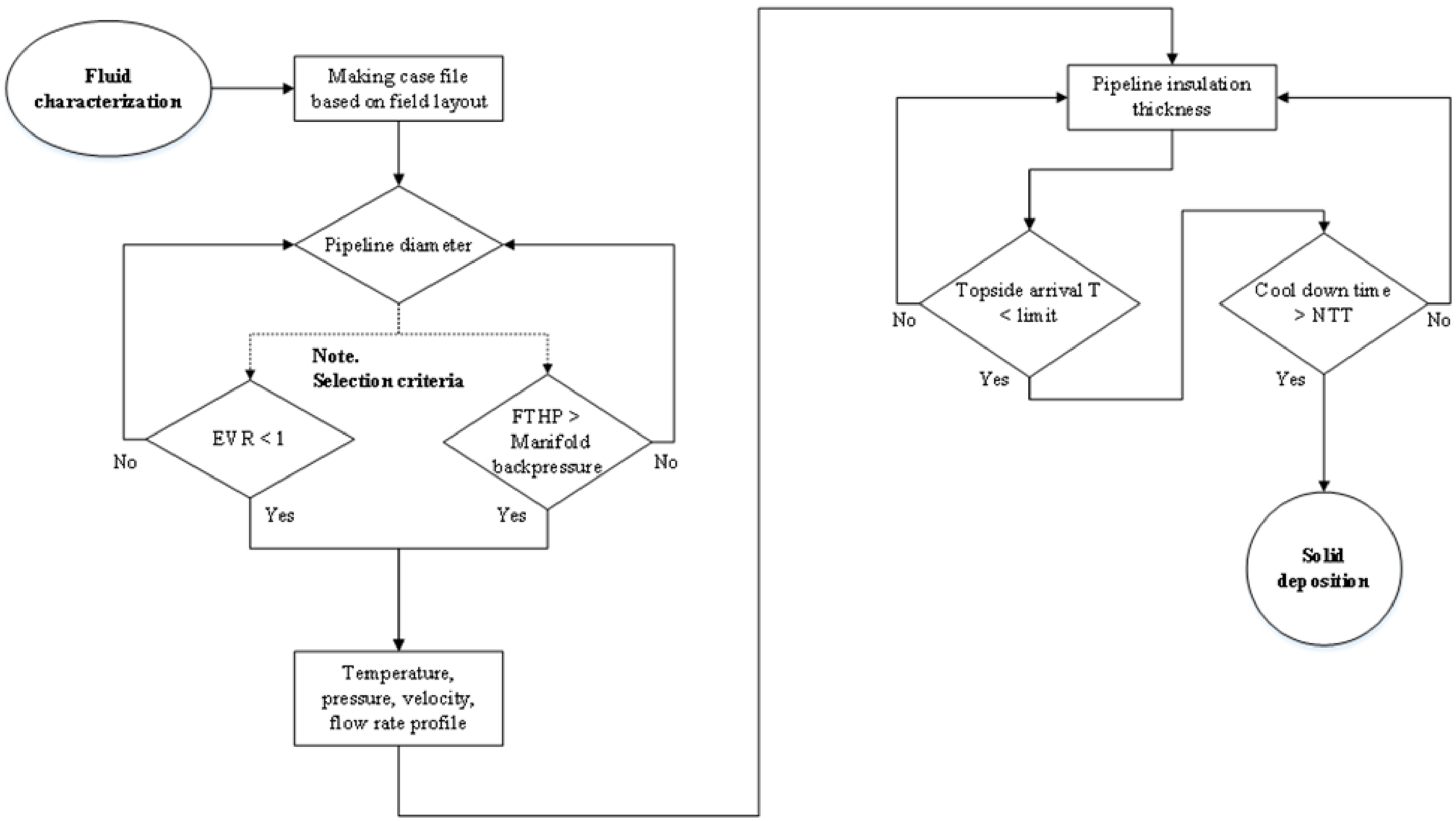
- Stage 4

  : Following the company's internal design guideline, verify the design and operation philosophy of offshore and topside production systems

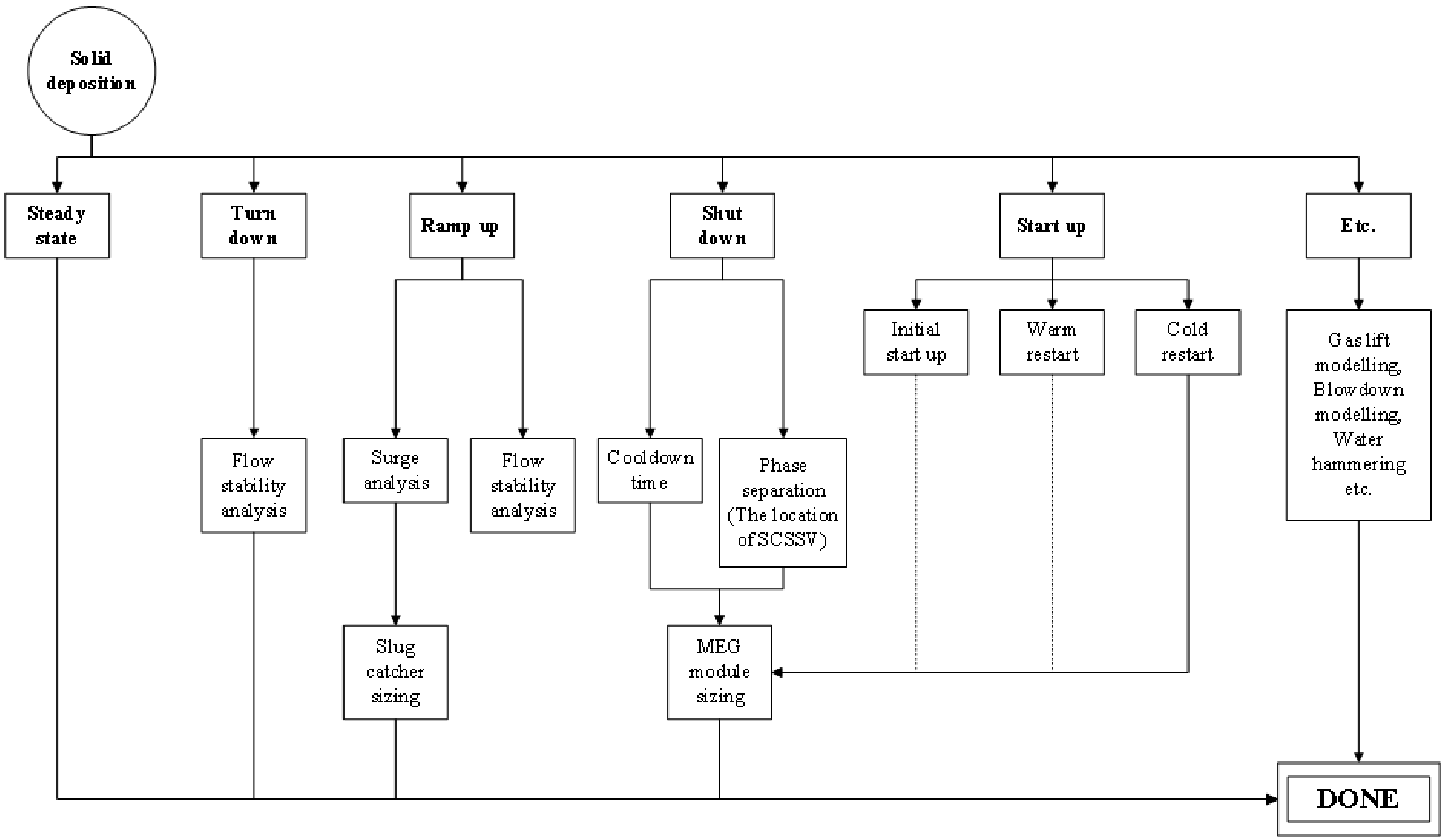
- Note 1. Fluid characterization



- Note 2. Multiphase flow simulation



• Note 3. Hydrate prevention



Summary

- Multiphase flow and solid deposition issues can be faced for the development of offshore oil and gas fields. Each issue has its own characteristic and needs special care to avoid unwanted outcomes such as production stoppage.

- The complex relationship between the flow assurance issues even make the problem worse, thus reliable work process is required.

- The flow assurance work process is composed of i) fluid characterization, ii) thermal/hydraulic analysis, iii) solid deposition analysis, and iv) production system design.

- The work process provide detailed approach to conduct flow assurance study for target offshore field by incorporating multiphase flow simulation with OLGA. It will provide an insight to field engineers to design and operation of their production system

Thank you