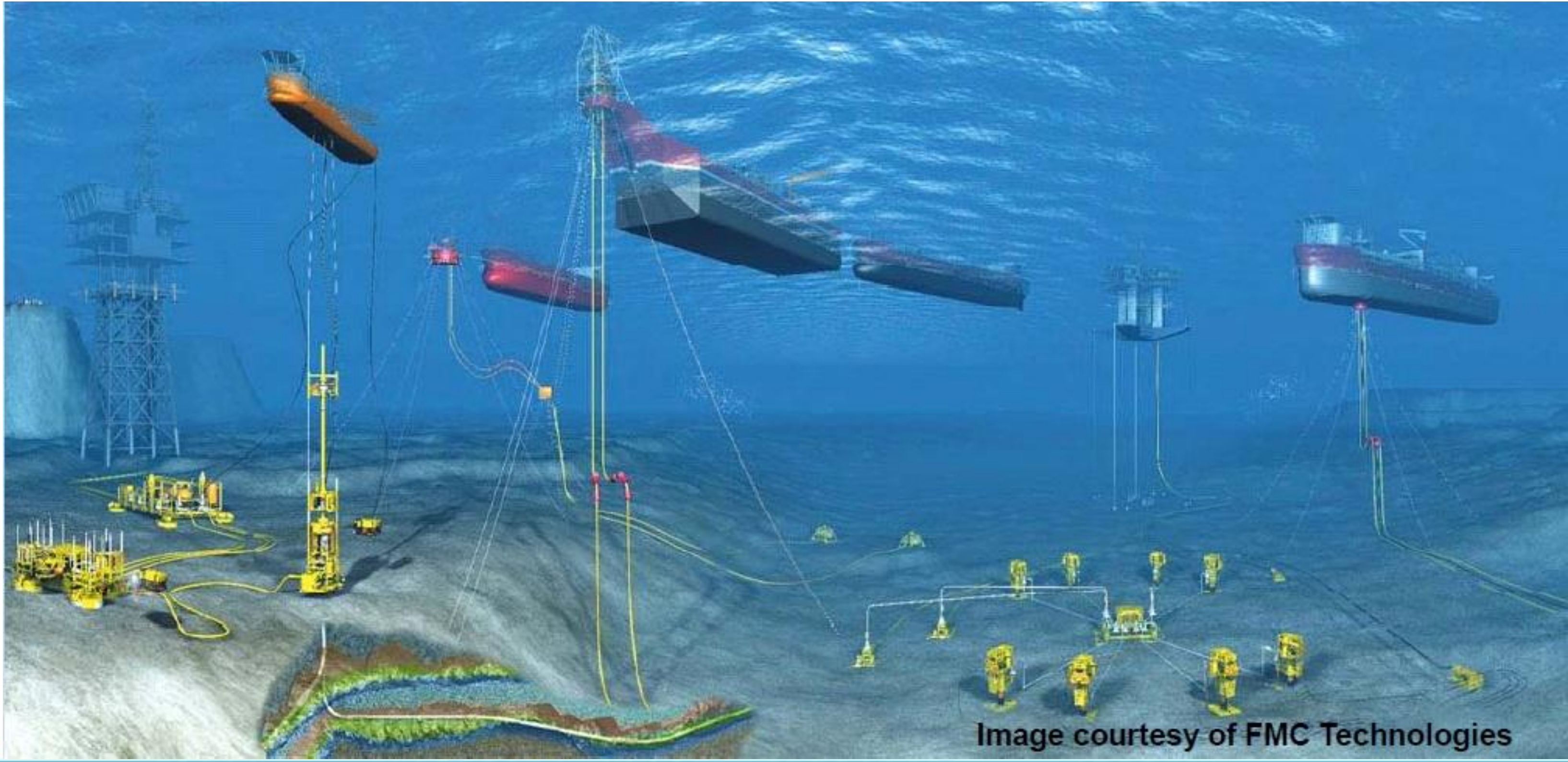
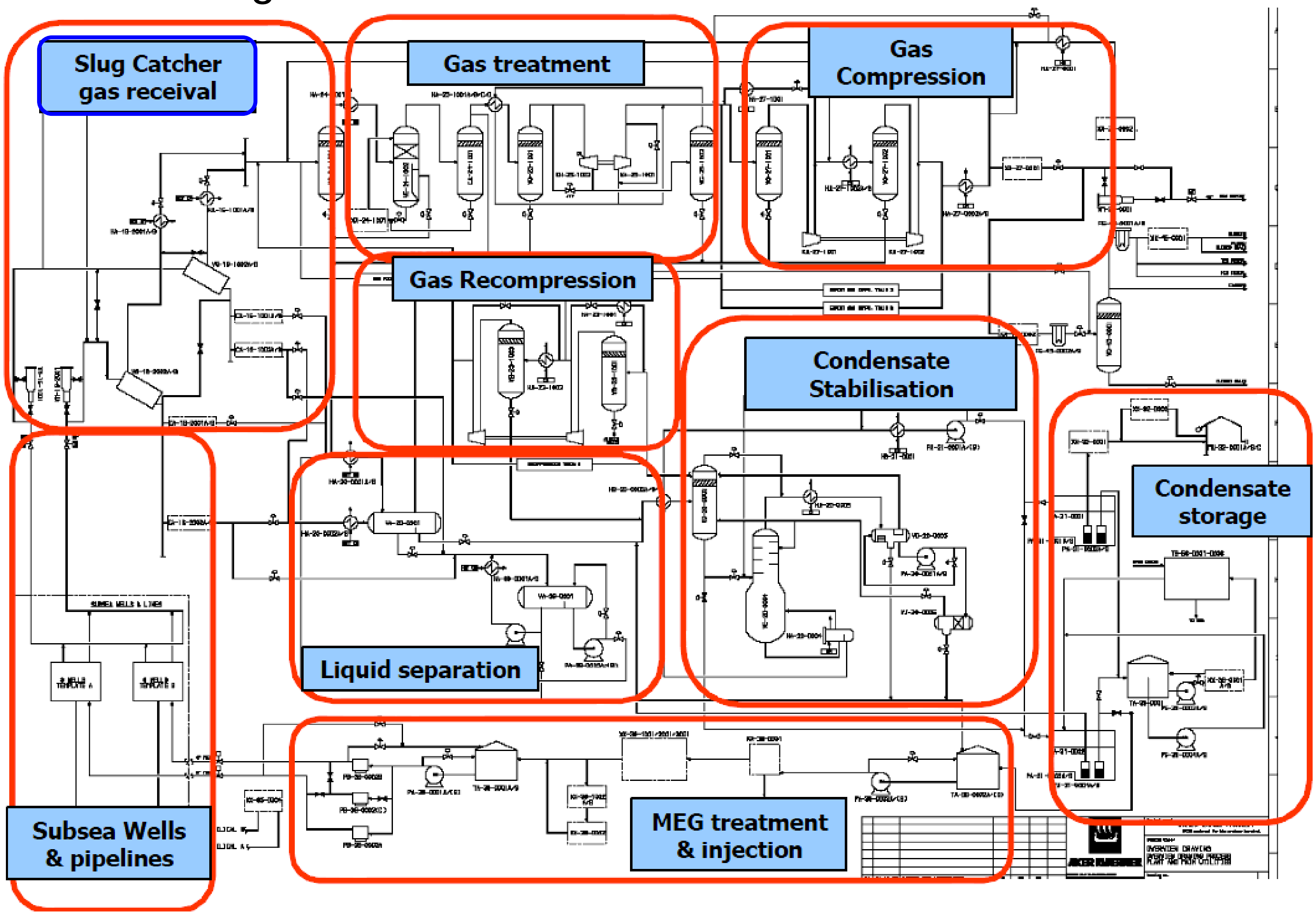


Introduction to Offshore Platform Engineering

Yutaek Seo

Gas condensate flowline slug catcher

- Ormen Lange




2 Slug Catcher units 1500m³ capacity
Can be connected to provide 3000m³ capacity

Inlet receiving

- Gas and liquids that enter the gas processing facilities pass emergency shutdown valves, and then go to inlet receiving, where condensed phases drop out. Gas from inlet receiving goes to inlet compression if necessary, and the liquids go to storage for further processing.

- Separator principles

: Effective phase separators protect downstream equipment designed to process a single phase. It is the critical first step in most processes in gas plants and typically is a simple vessel with internal components to enhance separation.

Slugging during ramp up and pigging

- Ramp Up:

  : Total Liquids Produced

  = holdup at the lower flowrate (minus) holdup at the higher rate.

  : The actual liquid production rate during this period will depend on the fluids, the flowline design and the flow conditions.

- Pigging: The greatest effects on liquid production during pigging occur with gas condensate flowlines. The entire flowline liquid holdup (except for the pig by-pass volume) will be produced in front of the pig.

Need for a slug catcher

- During non-steady state conditions (such as start-up, shutdown, turndown, and pigging) or when slugging during normal production occurs (low flowrates)
- The process controllers alone may not be able to sufficiently compensate for the wide variations in fluid flow rates, vessel liquid levels, fluid velocities, and system pressure caused by the slugs

Hydrodynamic slug size prediction (FPS vs SI)

- $$\ln(L_s) = -25.4144 + 28.4948\,(\ln(d))^{0.1}$$

  where :

  L_s = *average slug length , ft*

  d = *pipe inside diameter , in*

- $$\ln(L_s) = -65.807 + 59.115\,(\ln(d))^{0.1}$$

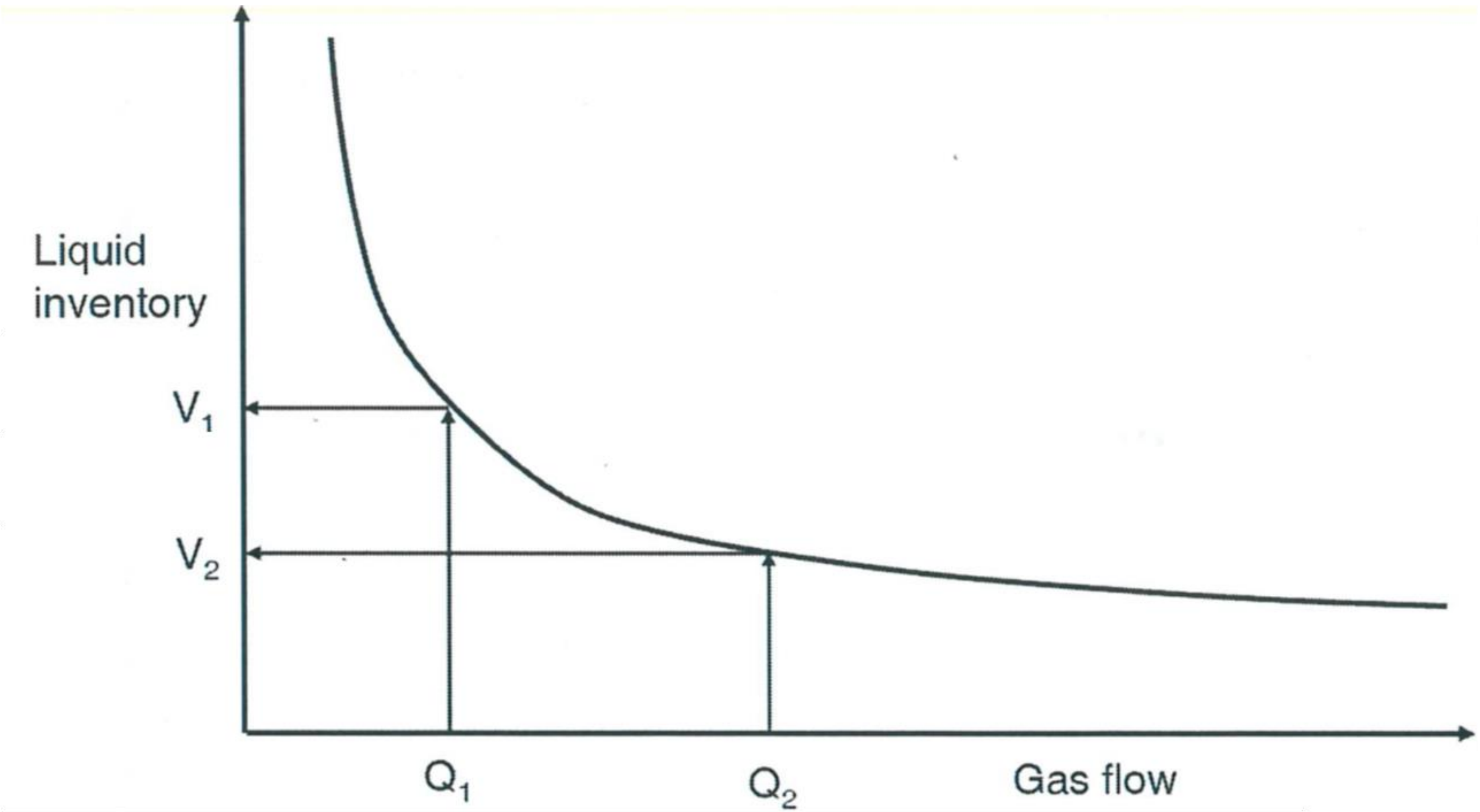
  where :

  L_s = *average slug length, m*

  d = *pipe inside diameter, mm*

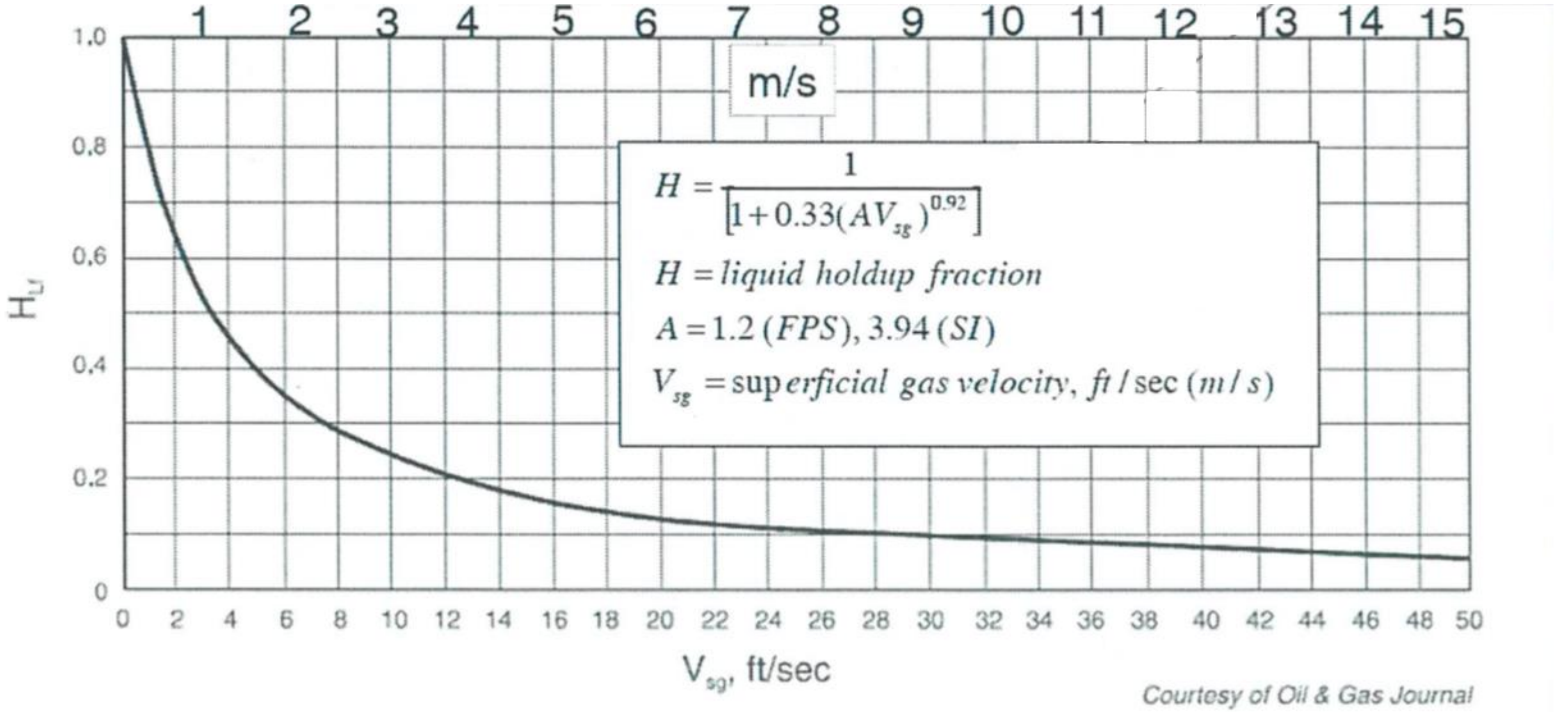
- Design slug length typically taken as 4 ~ 5 times L_s

Pipeline liquid holdup



Simple holdup correlation - Flanigan

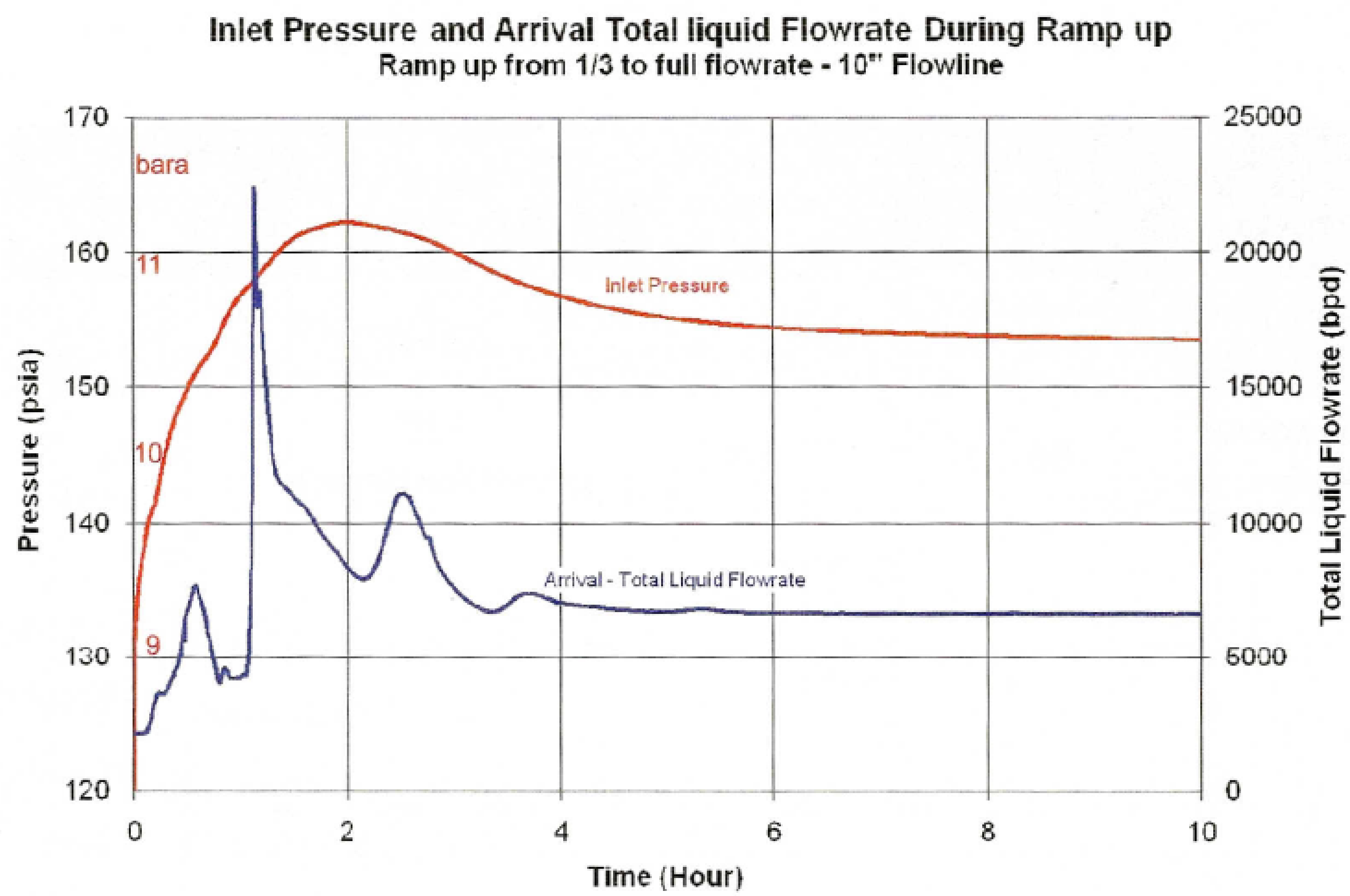
- Slug size is based on “Hold Up” difference between flow rate 1 and 2



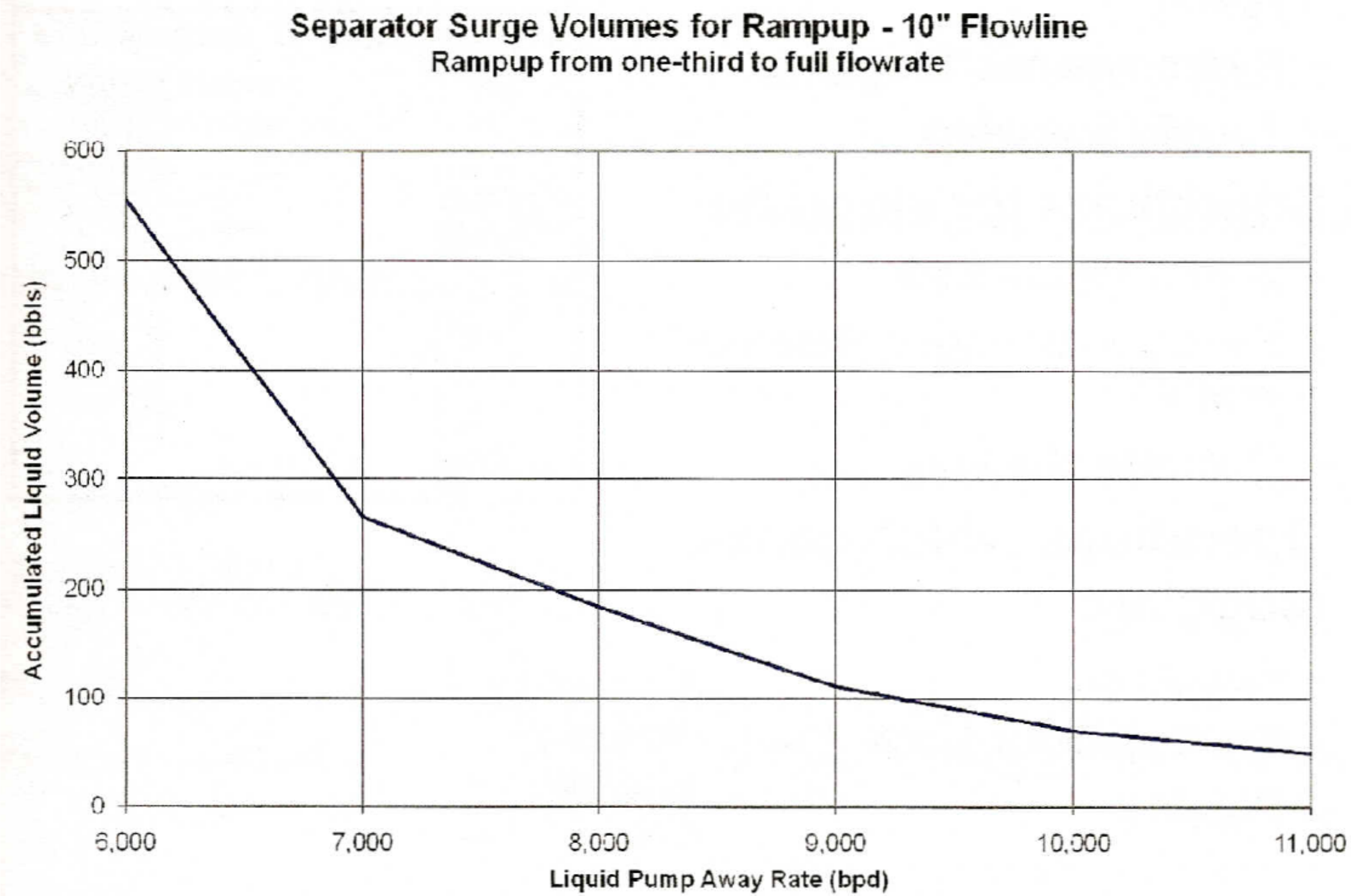
where, $V_{sg} = A\frac{q_g\, z\, T}{d^2\, P}$

q_g *in MMm³/d, T in K, d in m, P in kPa, A in 5.19 (SI)*

Ramp up flowrates and pressure



Separator surge volume during ramp up

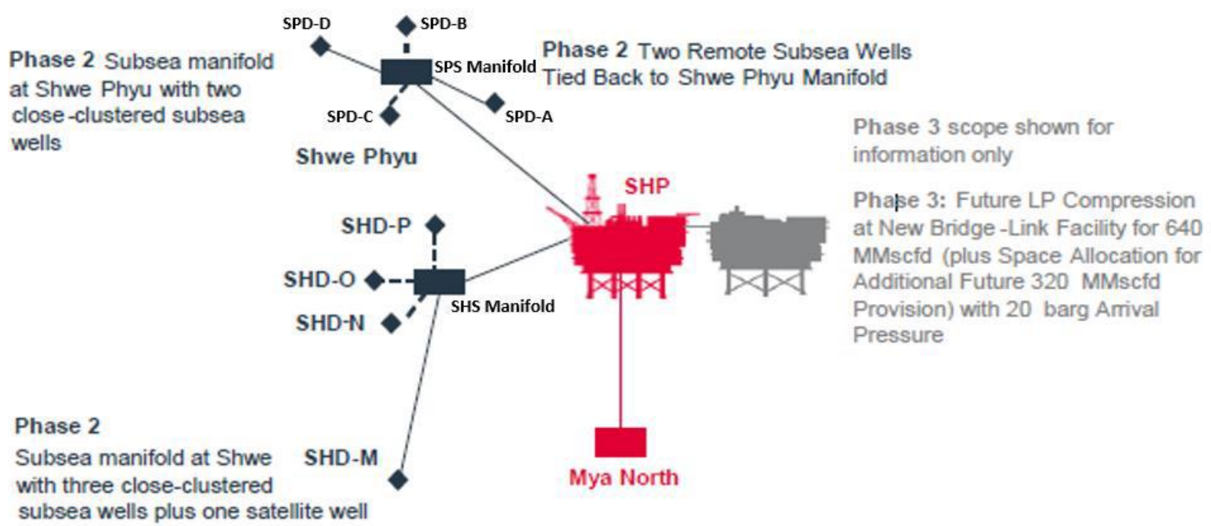


Simulation for Subsea-Topside integration

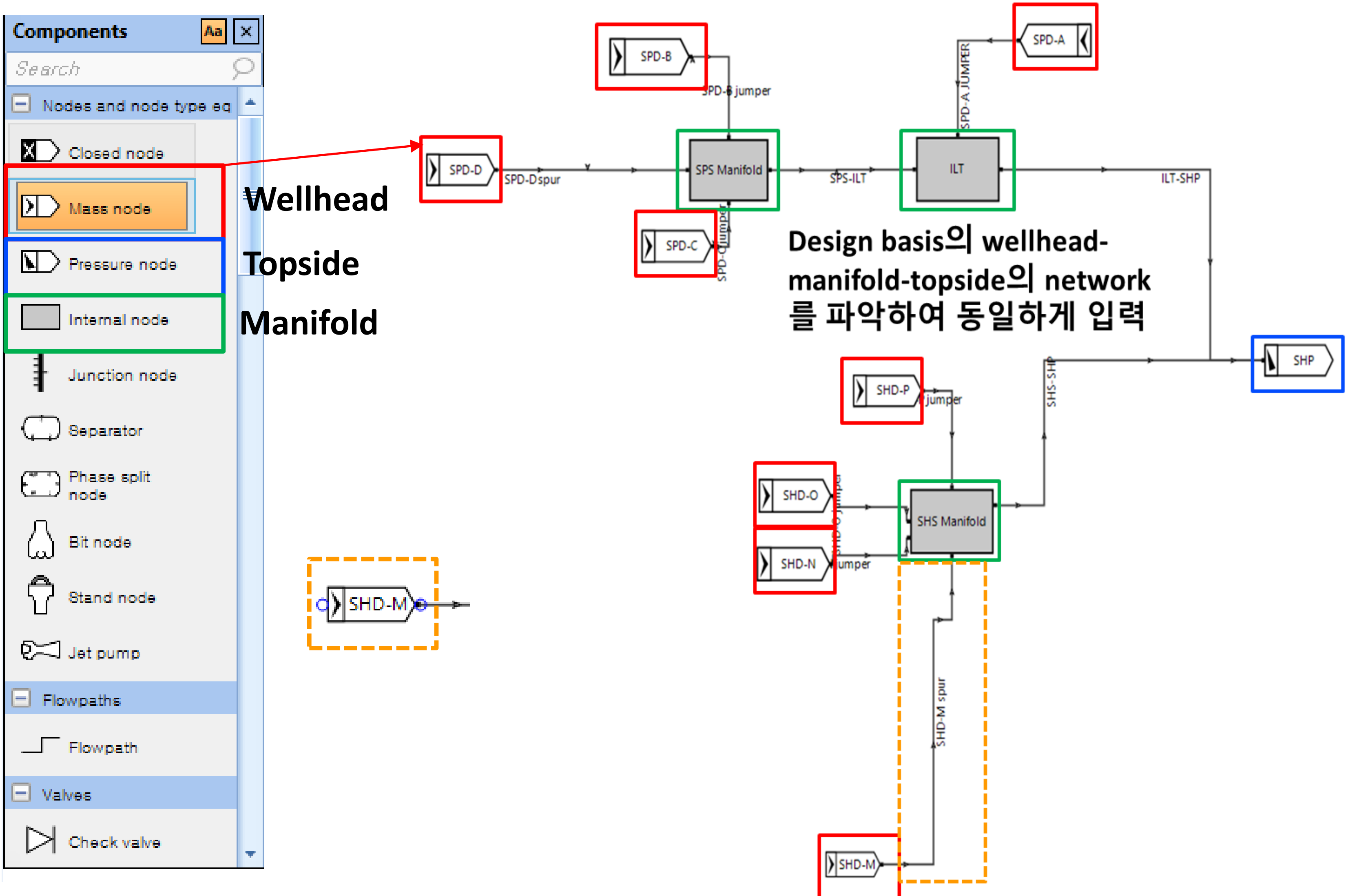
- The uses for transient multiphase flow *simulators* include*:*
  - Slug flow modeling
  - Estimates of the potential for terrain slugging
  - Pigging simulation
  - Identification of areas with higher corrosion potential, such as water accumulation in low spots in the line and areas with highly turbulent/slug flow
  - Startup, shutdown and pipeline depressurizing simulations
  - Slug catcher design
  - Development of operating guidelines
  - Real time modeling including leak detection
  - Operator training
  - Design of control systems for downstream equipment

Offshore platform operation

- Shwe Subsea (SHS) : three close-clustered wells(SPD-N,O,P)와 one remote well(SPD-M), one spare slot이 모여 SHP로 이송 (Five-slot manifold)
- Shwe Phyu manifold (SPS) : two close-clustered wells(SPD-B,C), two remote wells (SPD-A,D), two spare slot이 모여 SHP로 이송 (Six-slot manifold)
  - Base case : remote well SPD-A의 유체가 SPS에서 모인 후 SHP로 이송
  - Alternative case : SPD-A 의 유체가 main production pipeline 중간에 위치한 ILT에서 모여 SHP로 이송



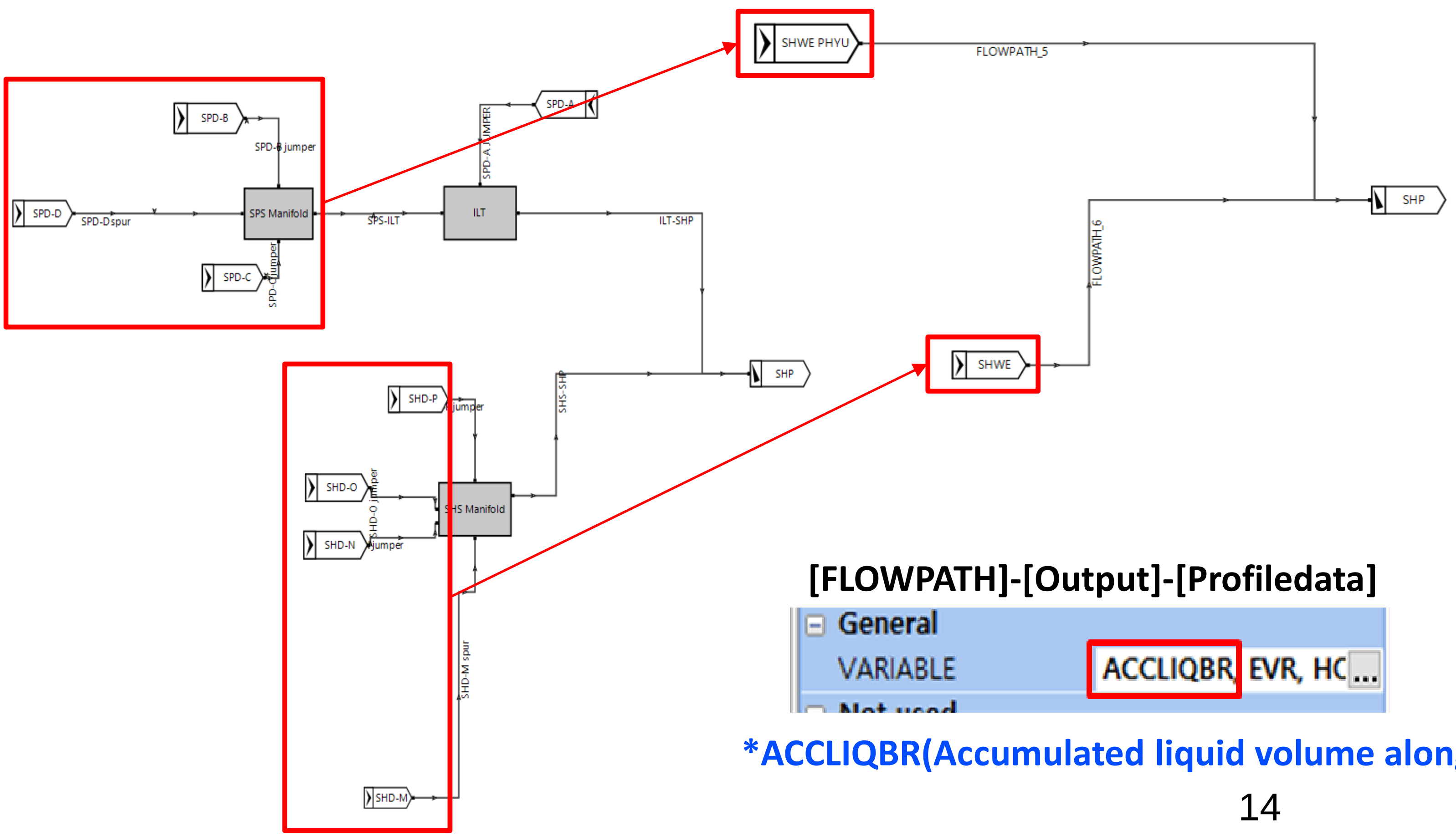
Multiphase flow simulation model



Design basis의 wellhead-manifold-topside의 network를 파악하여 동일하게 입력

Steady state operation: Liquid holdup analysis

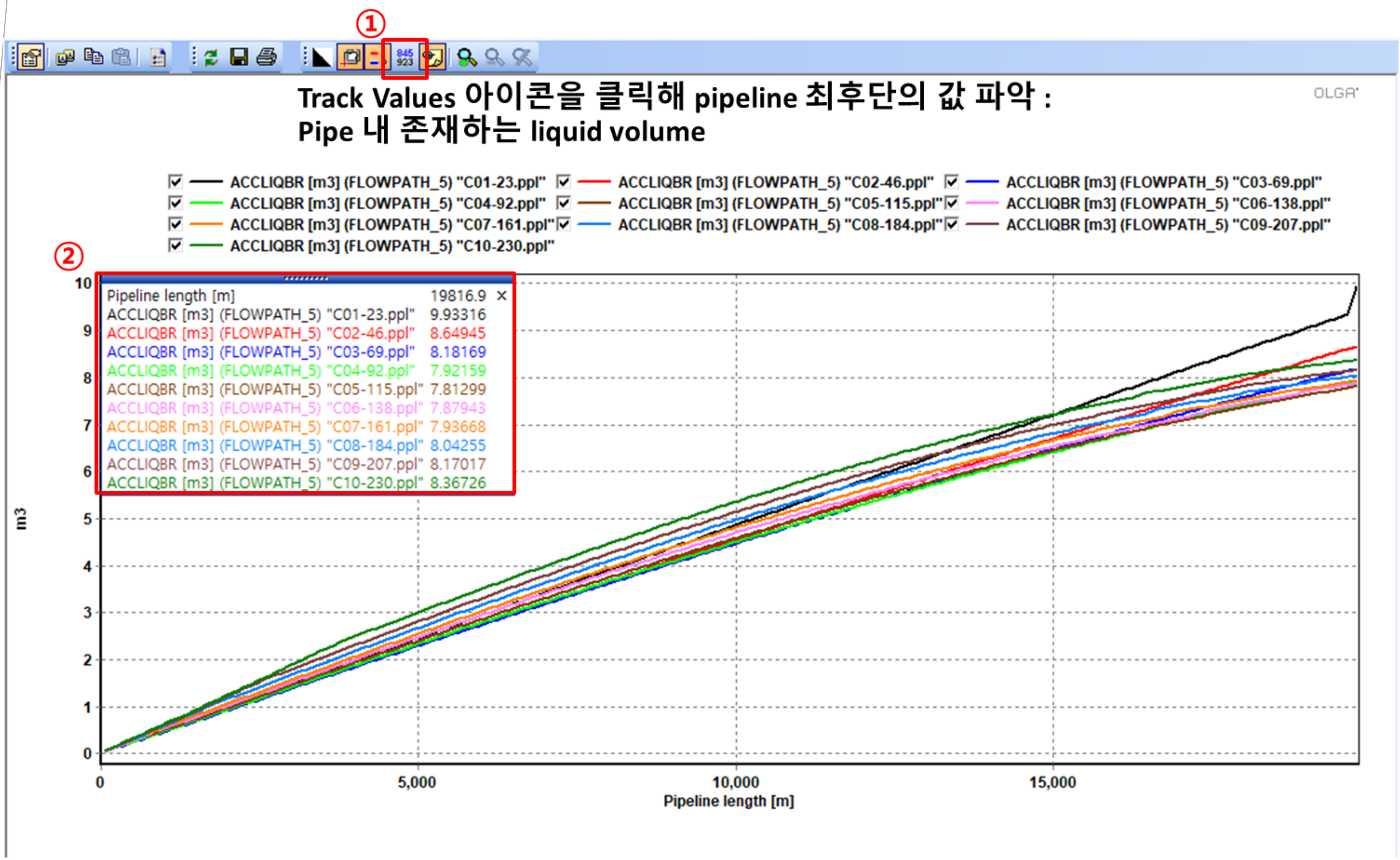
- Liquid holdup 분석은 jumper, spur line을 제외한 main pipeline에서 수행.
- Maximum well deliverability 유량인 230MMSCFD(Shwe phyu), 190 MMSCFD (Shwe)를 기준으로 10%~100% 유량일 때의 pipe 내 liquid volume을 계산



[FLOWPATH]-[Output]-[Profiledata]

***ACCLIQBR(Accumulated liquid volume along branch)**

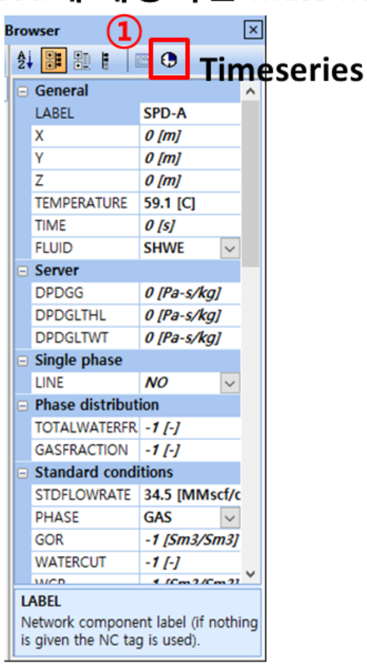
Track Values 아이콘을 클릭해 pipeline 최후단의 값 파악 :
Pipe 내 존재하는 liquid volume

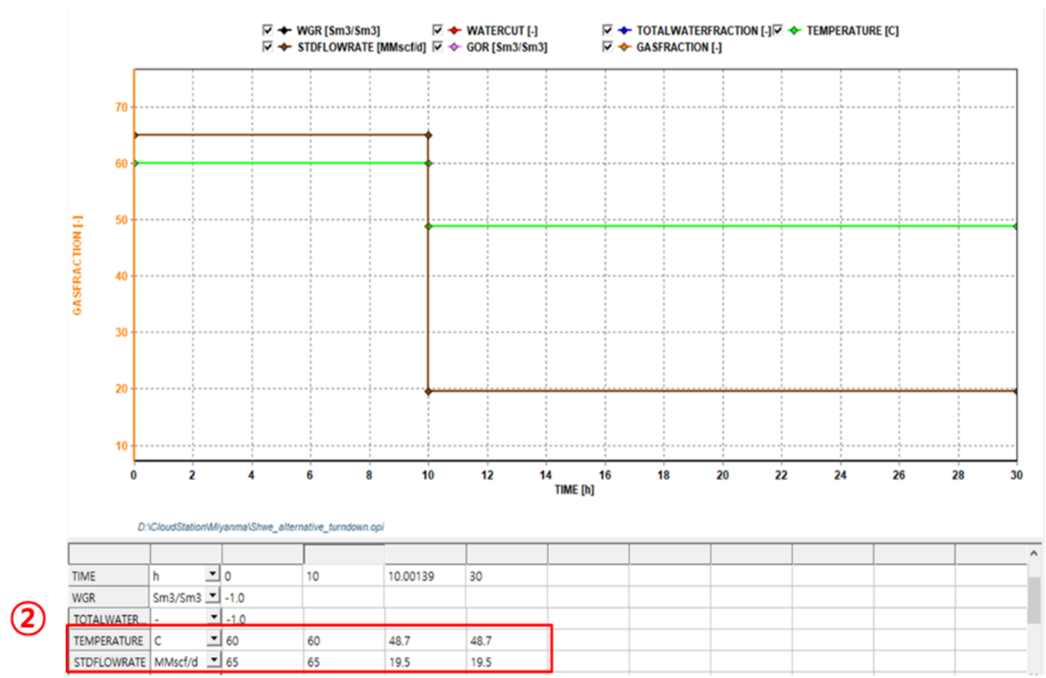


Transient operation: Turndown

- Steady-state analysis를 통해 minimum turndown rate 계산 가능.
  - HP condition : maximum flowrate의 30%
  - LP condition : maximum flowrate의 20%
- Transient operation scenario: 100% 유량으로 운전하는 도중에 minimum turndown 유량으로 5초 동안 빠르게 subsea well choke valve를 닫는 시나리오

각 Wellhead에 해당하는 Mass node

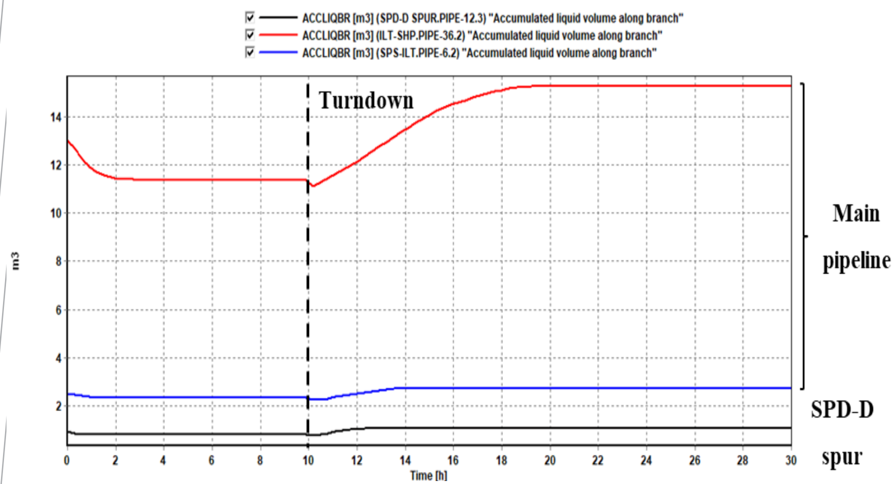




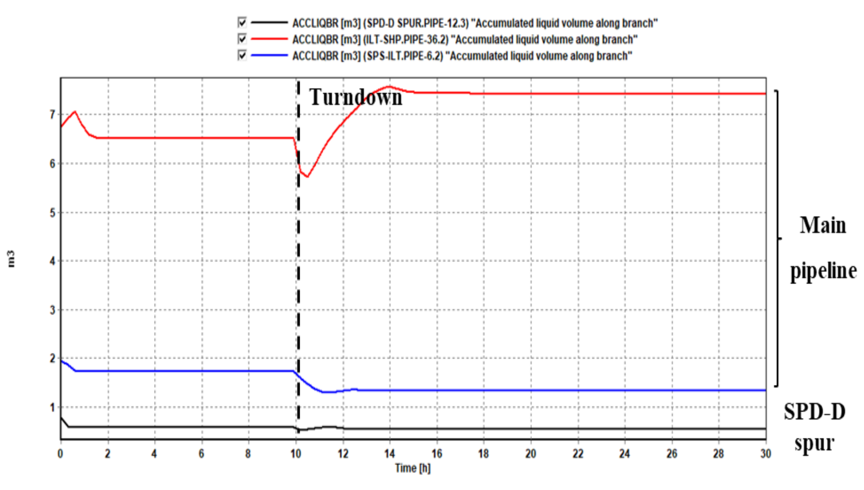
***모든 mass node의 timeseries 각각 설정**

Pipeline 내 liquid 양 변화 [ACCLIQBR]

HP condition



LP condition

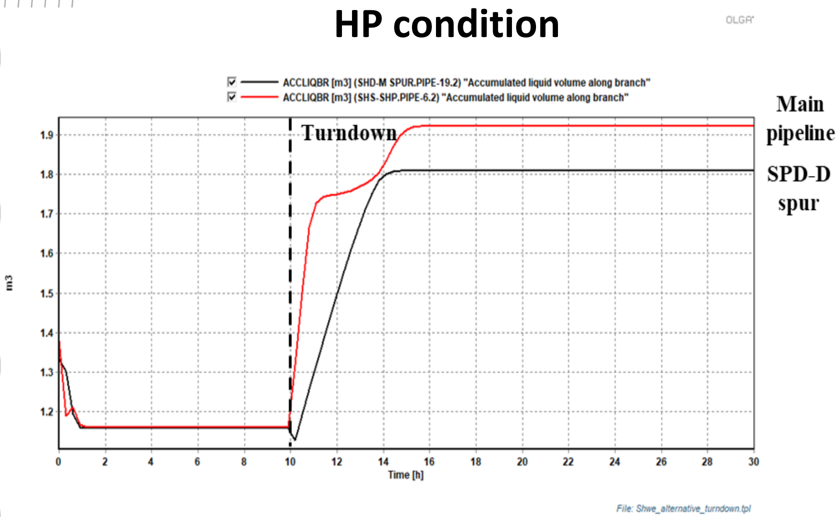


- HP condition
  - main pipeline에서는 약 10시간 동안 4.25m³의 liquid가 pipeline 내에 추가적으로 증가함
  - turndown 시 SPD-D spur에서는 약 2.5시간 동안 0.24m³ 의 liquid가 추가적으로 pipeline 내에 쌓이게 됨

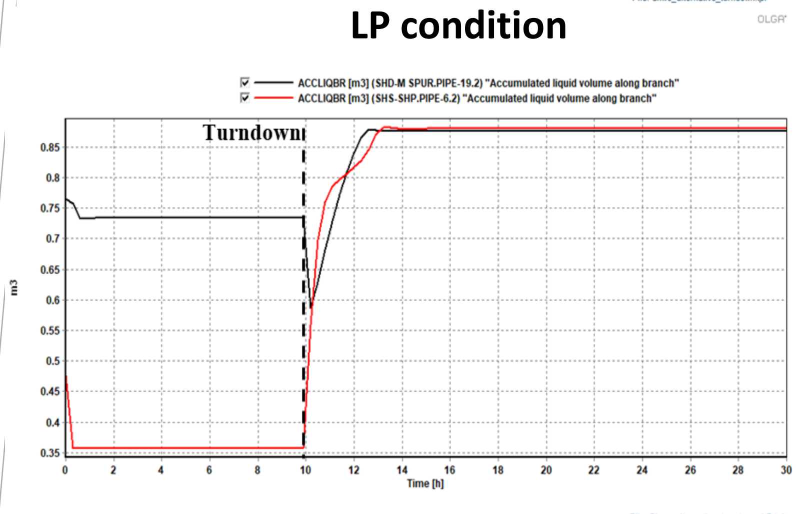
- LP condition
  - SPD-D well에서 manifold 까지의 pipeline 내 liquid 양은 큰 변화 없음.
  - main pipeline의 경우 8시간동안 0.52m³의 liquid가 추가적으로 더 쌓이게 됨

Pipeline 내 liquid 양 변화 [ACCLIQBR]

HP condition



LP condition

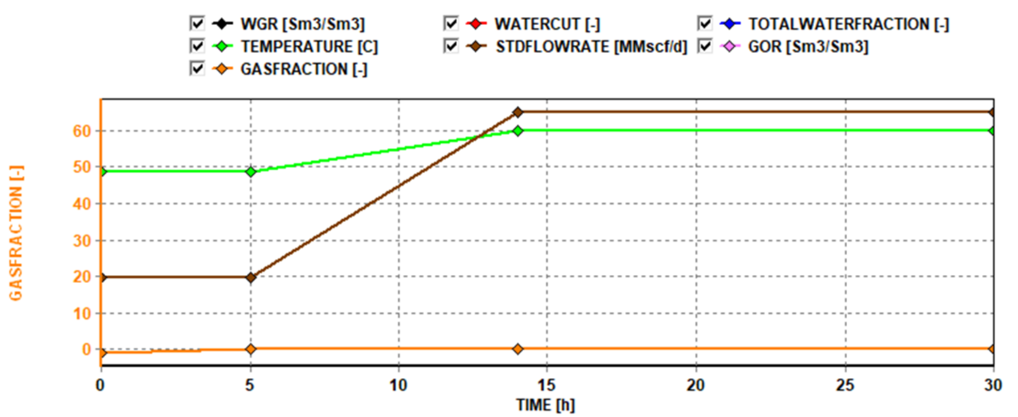


- HP condition
  - SPD-M well에서 manifold 사이의 pipeline의 경우 5시간 동안 0.66m^{3}의 liquid가 추가적으로 쌓이게 됨
  - Main pipeline의 경우 6시간 동안 0.73m^{3}의 liquid가 추가적으로 pipeline 내에 축적됨
- LP condition
  - SPD-M well에서 manifold 사이의 pipeline의 경우 4시간 동안 0.14m^{3}의 liquid가 추가적으로 쌓이게 됨
  - Main pipeline의 경우 6시간 동안 0.52m^{3}의 liquid가 추가적으로 pipeline 내에 쌓이게 됨

Transient operation: Ramp-up

- Minimum turndown rate에서 maximum flowrate으로 생산량을 증가시킬 때 나타나는 결과 시뮬레이션
- Turndown 운전에서 1) 4시간/ 2) 24시간 동안 ramp up 하는 시나리오
- Ramp-up 시 topside 쪽으로 유입되는 liquid가 정량적 분석 - QLST

각 mass node의 timeseries



D:\CloudStation\Miyanma\Shwe_alternative_rampup_HP.opi

	Units				
TIME	h	0	5	14	30
WATERCUT	-	-1.0			
TOTALWATER	-	-1.0			
TEMPERATURE	C	48.7	48.7	60	60
STDFLOWRATE	MMscf/d	19.5	19.5	65	65

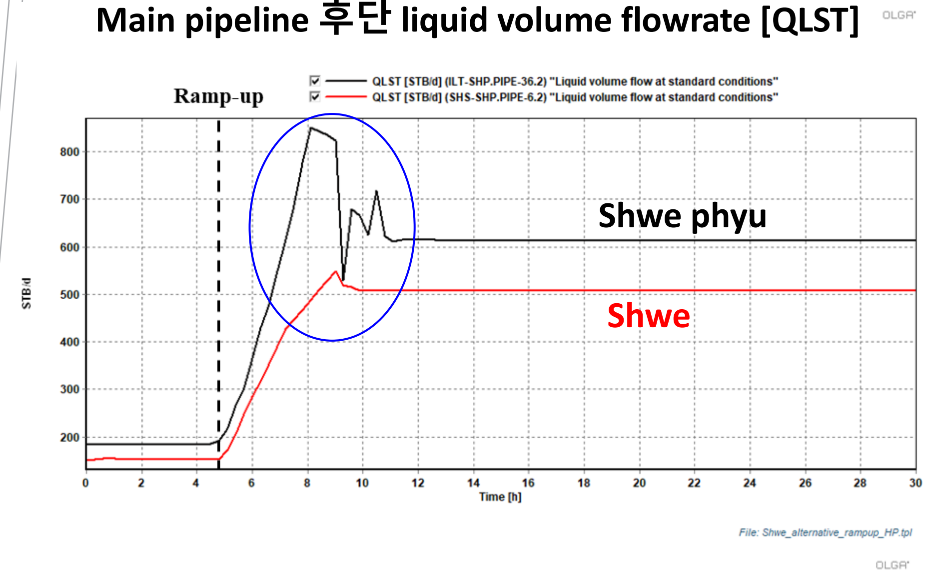
***모든 mass node의 timeseries 각각 설정**

Main pipeline 끝에 Trenddata : QLST 추가

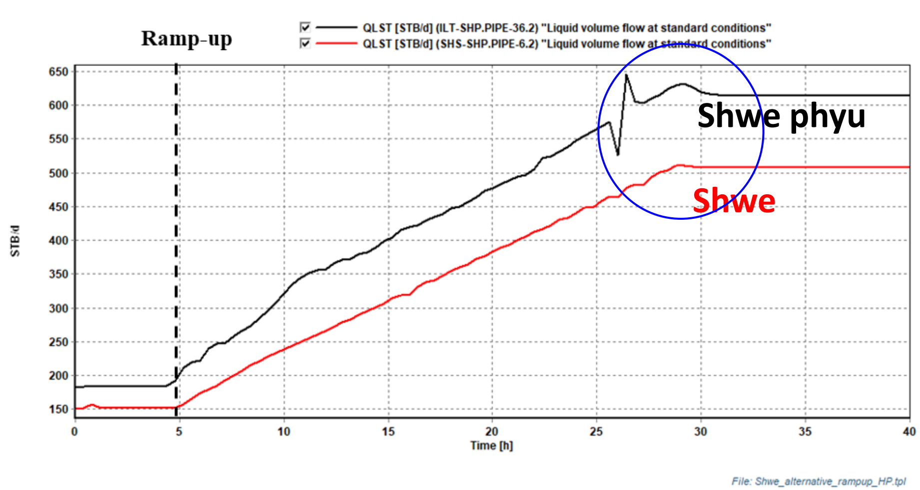
Position	
PIPE	PIPE-36
SECTION	2 [max 3]
General	
VARIABLE	ACCLIQBR, QLST
Not used	

***QLST : liquid volume flow at standard condition**

Main pipeline 후단 liquid volume flowrate [QLST]



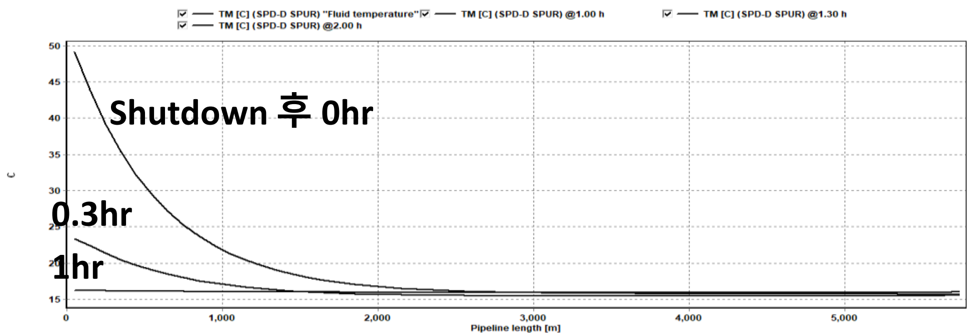
- 4 hour ramp-up
  - Maximum arrival liquid flowrate
  : 850 bbl/d (Shwe phyu)
  : 545 bbl/d (Shwe)
  - Ramp-up 운전 도중 플랫폼으로 유입되는 liquid hydrocarbon을 수용 가능한 inlet facility 필요



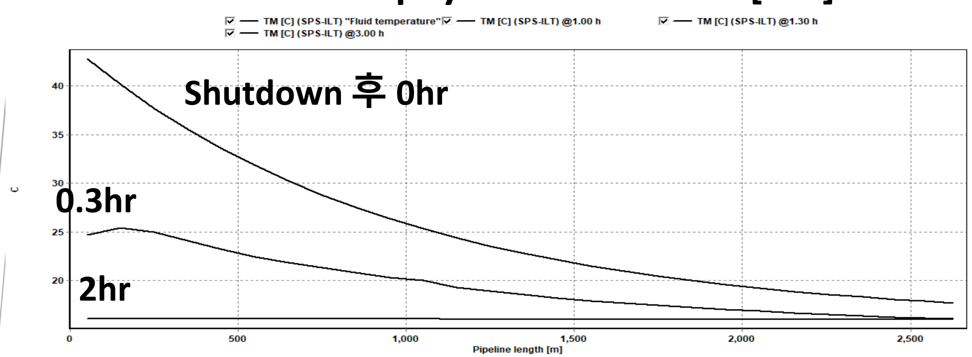
- 24 hour ramp-up
  - 4시간동안 ramp-up 시키는 것에 비해 확연히 maximum liquid flowrate이 줄어든 것을 확인 가능

Transient operation: Shut-down

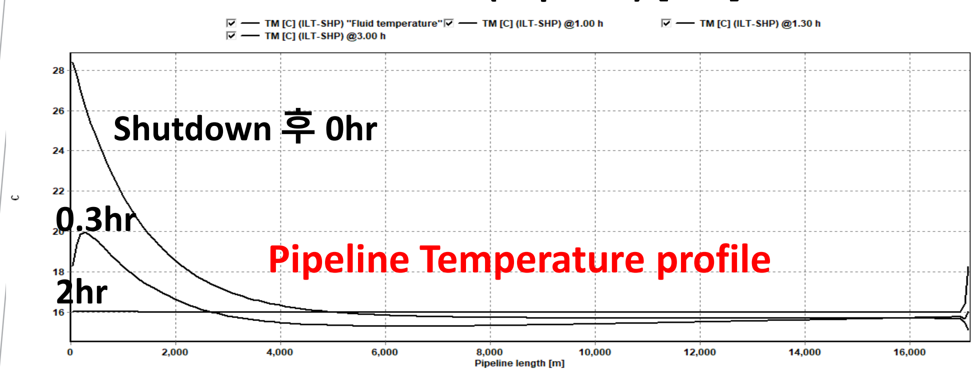
SPD-D well ~ Shwe phyu manifold [TM]



Shwe phyu manifold ~ ILT [TM]



ILT ~ SHP(Topside) [TM]



- SPD-D spur line

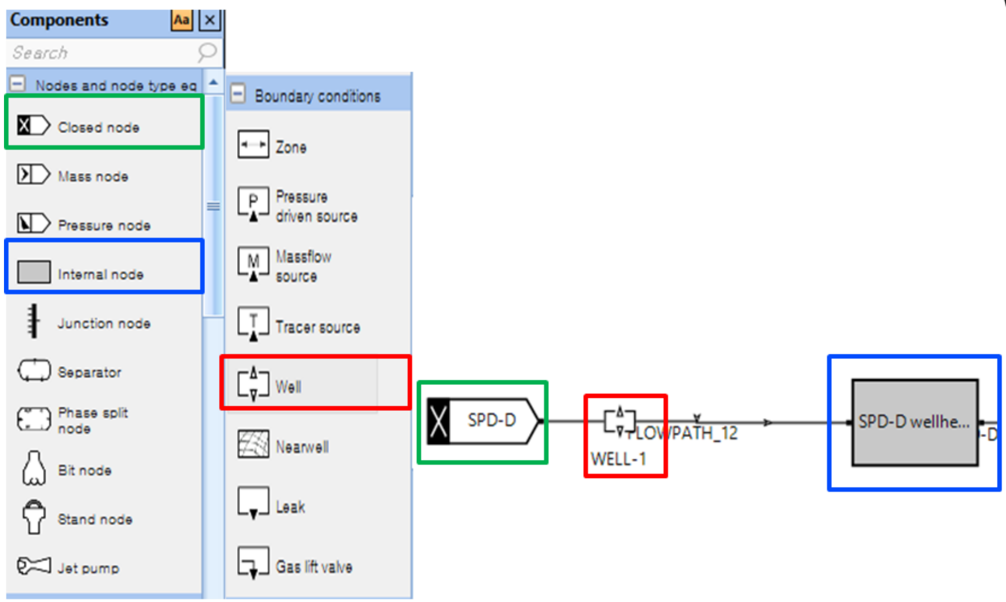
  : shutdown 이후 한시간이 지난 뒤 주변 온도와 평형

- Main pipeline

  : shutdown 이후 두시간이 지난 뒤 주변 온도와 평형

Transient operation: Start-up

- Wellhead에 위치한 subsea choke가 열리면서 나타나는 Joule-Thompson cooling 에 의해 downstream쪽 온도가 얼마나 낮아지는지 분석 : hydrate inhibition 분석
- Subsea choking에 의해 wellbore 부터 wellhead까지의 tubing이 packing되는 것을 모사하기 위해 OLGA의 well module 필요



Well module parameter 예시

General	
LABEL	BDC1C_1
PRODOPTION	FORCHHEIN
INJOPTION	FORCHHEIN
RESPRESSURE	406.9 [bara]
RESTEMPERATU	152 [C]
TIME	*0 [s]*
LOCATION	*MIDDLE*
ISOTHERMAL	*YES*
Standard conditions	
WATERCUT	*-1 [-]*
WGR	*-1 [Sm3/Sm3]*
CGR	*-1 [Sm3/Sm3]*
GORST	*-1 [Sm3/Sm3]*
Position	
PIPE	PIPE-1
SECTION	1 [max 6]
Well inflow coefficients	
BINJ	0
CINJ	0
BPROD	0.030244
CPROD	5.8e-011
Not used	

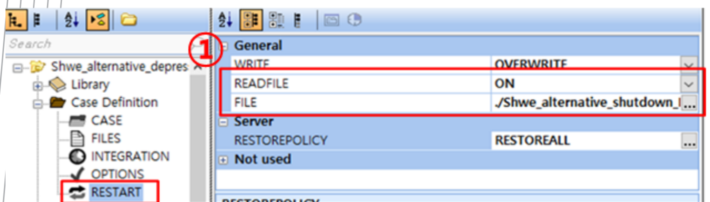
① **Well option 선택**

② **Reservoir P/T 입력**

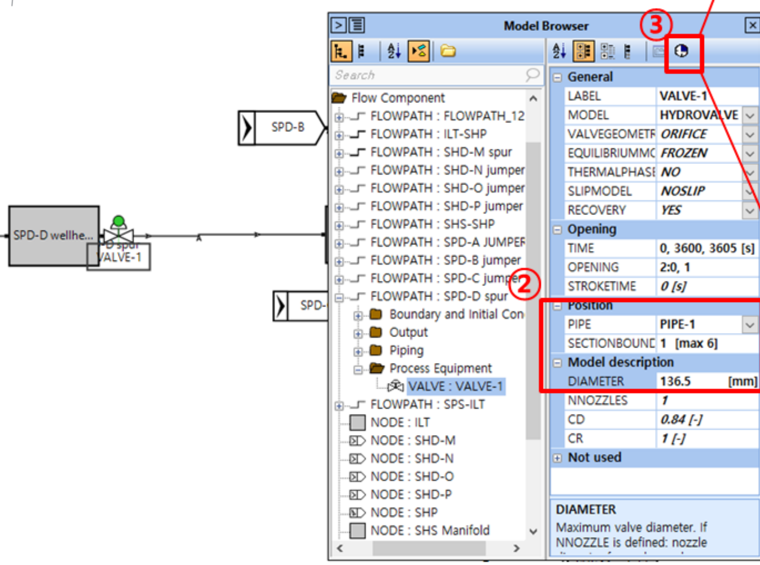
③ **Well module position**

④ **Well coefficients**

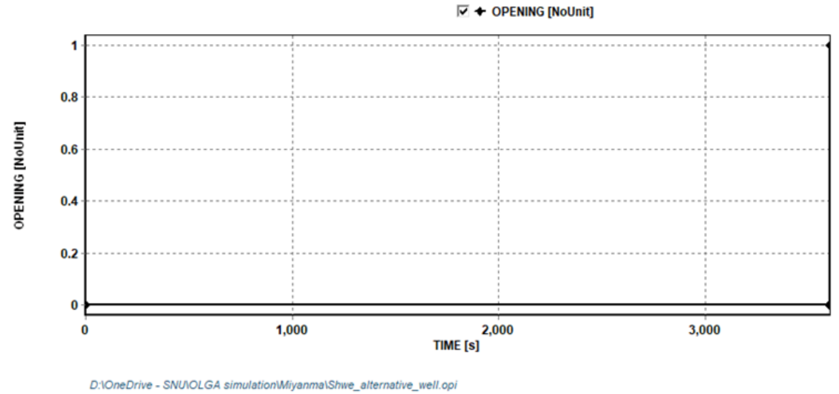
[Case Definition]-[RESTART]



Valve wellhead 후단에 설치 후 time series 설정

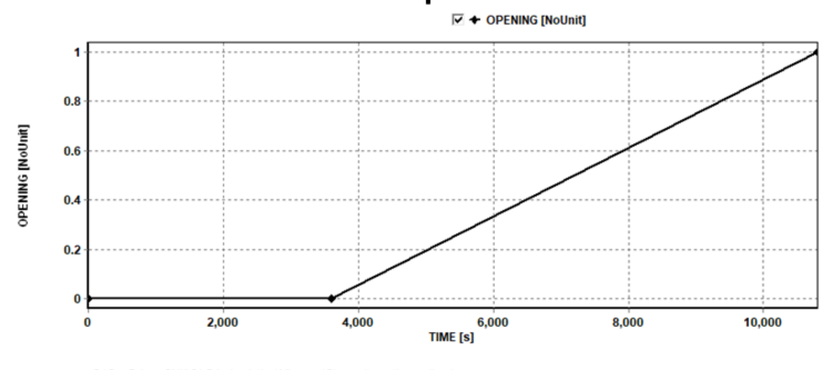


Instant start-up (5sec)

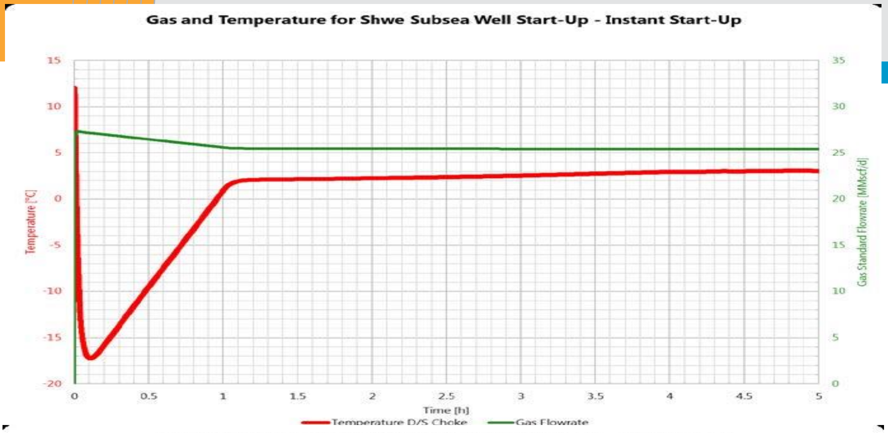


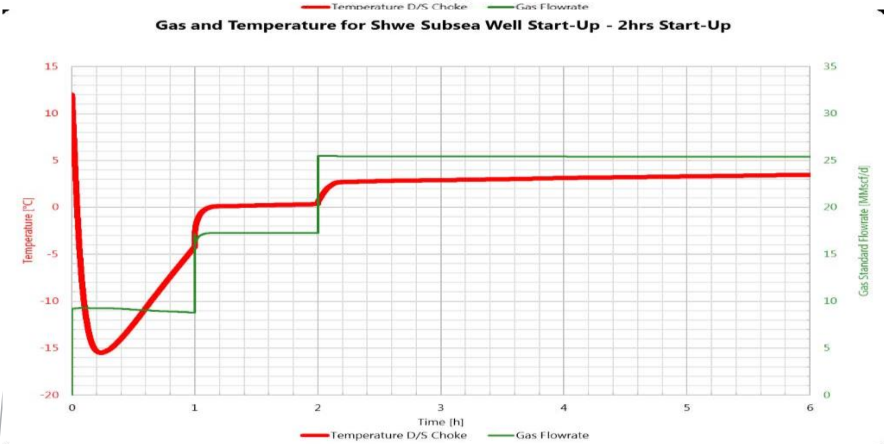
	Units			
TIME	s	0	3600	3605
OPENING	NoUnit	0	0	1

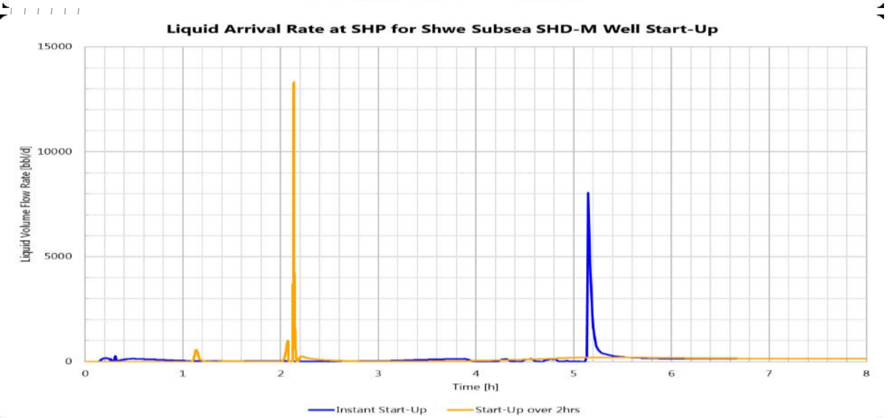
Start-up over 2 hours



	Units			
TIME	s	0	3600	10800
OPENING	NoUnit	0	0	1







- Instant start-up

  Minimum temperature : -17.5ºC

- 2hr start-up
  - Minimum temperature : -16.8 ºC
  - 1시간 start-up에 비해 최저 온도 상승
  - 1-2hr 사이의 온도 상승은 liquid flow 의 갑작스런 증가에 의함

- Liquid arrival rate at topside
  - Instant start-up : 8050 bbl/d
  - 2hr start-up : 13300 bbl/d
  - 매우 빠른 속도로 liquid가 들어오며, inlet facility 설계에 반영 필요.

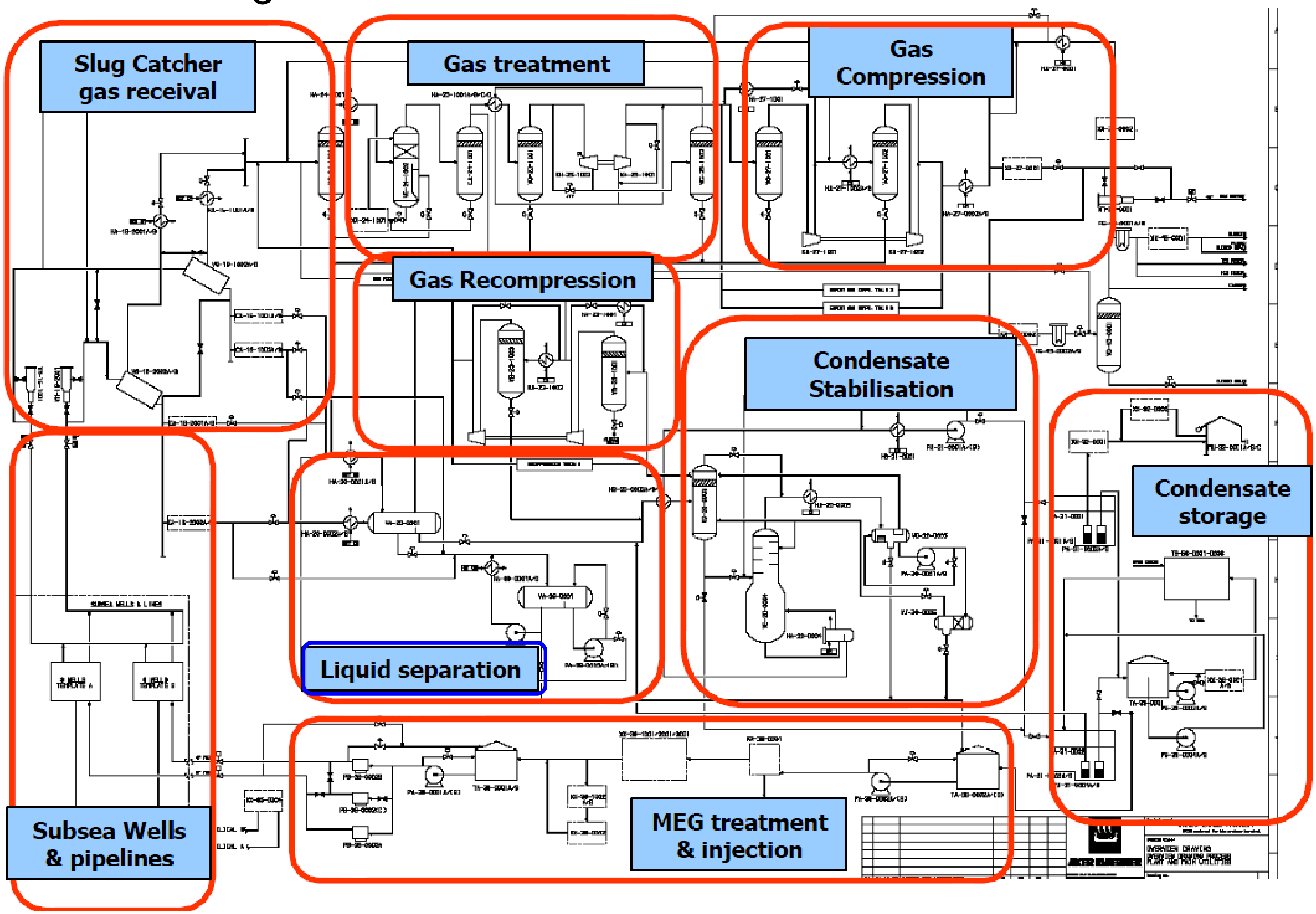
*비교 – ramp up liquid arrival rate

: 850 bbl/d (Shwe phyu)

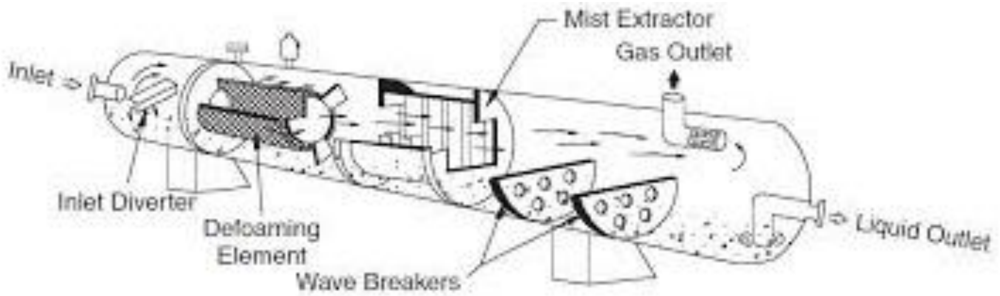
: 545 bbl/d (Shwe)

Gas condensate flowline slug catcher

- Ormen Lange



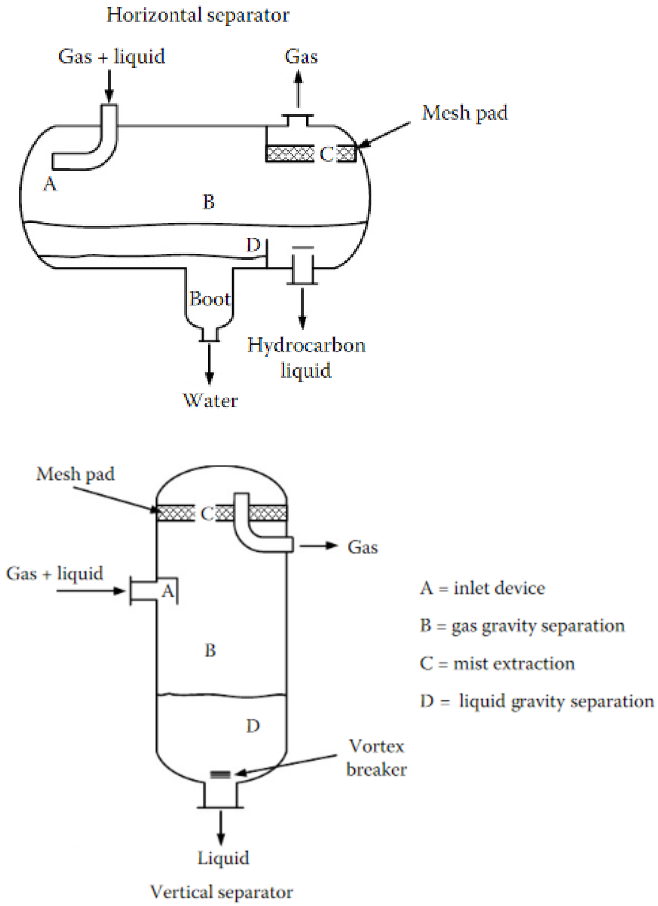
Horizontal separator



Gas-Liquid separation

- Separator vessel orientation can be vertical or horizontal.
- Vertical separators are most commonly used when the liquid-to-gas ratio is low or gas flow rates are low. They are preferred offshore because they occupy less platform area.
- However, gas flow is upwards and opposes the flow of liquid droplets. Therefore, vertical separators can be bigger and, thus, more costly than horizontal separators. Inlet suction scrubbers at compressor stations are usually vertical.
- Horizontal separators are favored for large liquid volumes or if the liquid-to-gas ratio is high. Lower gas flow rates and increased residence times offer better liquid dropout.
- The larger surface area provides better degassing and more stable liquid levels as well.

- Following figure shows a schematic of gas-liquid separators and indicates the four types of separation:
- Primary separation
- Gravity settling
- Coalescing
- Liquid collecting



Primary separation

- Primary separation is accomplished by utilizing the difference in momentum between gas and liquid.
- Larger liquid droplets fail to make the sharp turn and impinge on the inlet wall.
- This action coalesces finer droplets so that they drop out quickly.
- Although inlet geometries vary, most separators use this approach to knock out a major portion of the incoming liquid.

Gravity settling

- Gravity settling requires low gas velocities with minimal turbulence to permit droplet fallout.
- The terminal-settling velocity, V_T, for a sphere falling through a stagnant fluid is governed by particle diameter, density differences, gas viscosity, and a drag coefficient that is a function of both droplet shape and Reynolds number.
- the Reynolds number is defined as

$$N_{\mathrm{Re}} = D_P V_T \rho_g / \mu_g, \qquad (3.4)$$

  where D_p is particle diameter, ρ_g is the density, and μ_g is the viscosity.
- Thus, calculations for V_T are an iterative process.

Coalescing

- The coalescing section contains an insert that forces the gas through a torturous path to bring small mist particles together as they collect on the insert. These inserts can be mesh pads, vane packs, or cyclonic devices.

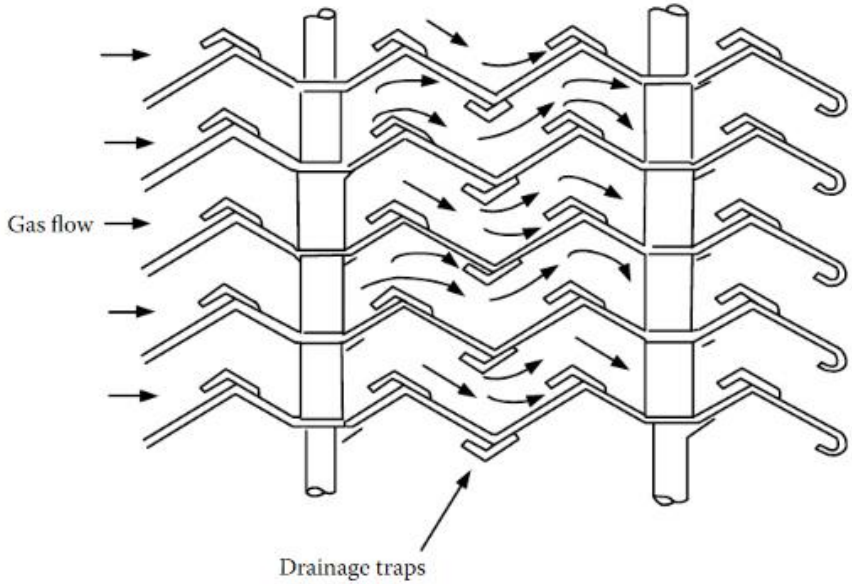
TABLE 3.2
Features of Mist Extracting Devices

	Wire Mesh	Vane Pack
Gas capacity factor, C in Equation 3.8, ft/sec (m/sec)	0.22 – 0.39 (0.067 – 0.12)	Horizontal flow 0.9 – 1.0 (0.27 – 0.30) Vertical flow 0.4 – 0.5 (0.12 – 0.15)
Droplet efficiency	99 – 99.5% removal of 3- to 10-micron droplets	99% removal of 10- to 40-micron droplets
Turndown range, % of design gas rate	30 – 110	Rapid decrease in efficiency with decreased gas flow
Pressure drop, inches of water (kPa)	< 1 (0.25)	0.5 to 3.5 (0.12 to 0.87)

Source: Engineering Data Book (2004b).

- Mesh pads are either wire or knitted mesh, usually about 6 inches (15 cm) thick, and, preferably, are mounted horizontally with upward gas flow, but they can be vertical.
- They loose effectiveness if tilted. Mesh pads tend to be more effective at mist removal than vane packs but are subject to plugging by solids and heavy oils.

- Following figure shows several elements of a vane pack, which are corrugated plates, usually spaced 1 to 1.5 inches (2.4 to 3.8 cm) apart, that force the gas and mist to follow a zigzag pattern to coalesce the mist into larger particles as they hit the plates.



- Coalesced drops collect and flow out the drainage traps in the plates. Although not as effective at removing small drops, they are ideal for “dirty” service because they will not plug.

Liquid collection

- The liquid collection section acts as a holder for the liquids removed from the gas in the above three separation sections.
- This section also provides for degassing of the liquid and for water and solids separation from the hydrocarbon phase.
- The most common solid is iron sulfide from corrosion, which can interfere with the liquid-liquid separation. If a large amount of water is present, separators often have a “boot,” as shown in the horizontal separator, at the bottom of the separator for the water to collect.
- The Engineering Data Book (2004) estimates that retention times of 3 to 5 minutes are required for hydrocarbon-water separation by settling.

Residence time for separator applications

- The residence time is simply the volume of the phase present in the vessel divided by the volumetric flow rate of the phase.
- Typical retention times for common gas-liquid separations

TABLE 3.3
Typical Retention Times for Gas-Liquid Separations

Type of Separation	Retention Time (Minutes)
Natural gas condensate separation	2 – 4
Fractionator feed tank	10 – 15
Reflux accumulator	5 – 10
Fractionation column sump	2[a]
Amine flash tank	5 – 10
Refrigeration surge tank	5
Refrigeration economizer	3
Heat medium oil surge tank	5 – 10[b]

[a] If the fractionator column sump is feeding a downstream fractionator column, it should be sized as a feed tank (McCartney, 2005).
[b] This vessel must have adequate space to allow for expansion of the heat medium from ambient to operating temperature (McCartney, 2005).

Source: Engineering Data Book (2004b).

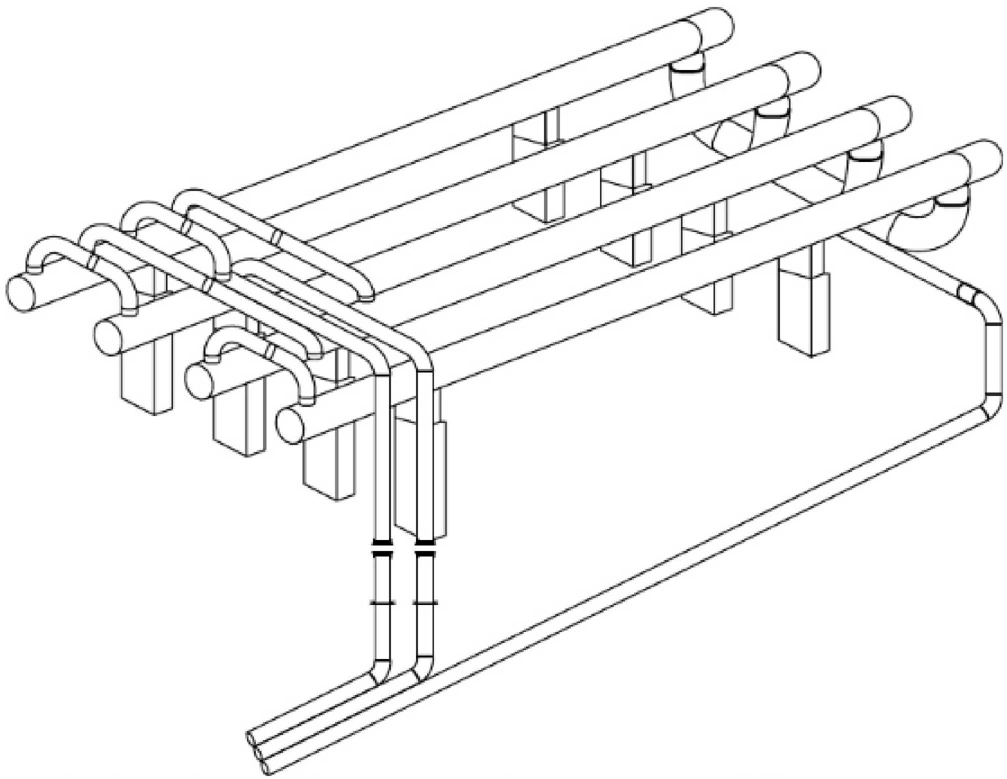
Slug catcher configurations

- This section briefly describes two kinds of slug catchers, manifolded piping and inlet vessels.
- The most difficult part of a slug catcher design is the proper sizing. Sizing requires knowledge of the largest expected liquid slug, as liquid pump discharge capacity on the slug catcher will be trivial compared with the sudden liquid influx.
- Manifolded Piping

  : One reason piping is used instead of separators is to minimize vessel wall thickness. This feature makes piping attractive at pressures above 500 psi (35bar).

  : The simplest slug-catcher design is a single-pipe design that is an increased diameter on the inlet piping. However, this design requires special pigs to accommodate the change in line size.

- A schematic of typical multi-pipe harp design for a slug catcher.



- The number of pipes varies, depending upon the required volume and operating pressure. Also, some designs include a loop line, where some of the incoming gas bypasses the slug catcher.
- Primary separation occurs when the gas makes the turn at the inlet and goes down the pipes. Liquid distribution between pipes can be a problem, and additional lines between the tubes are often used to balance the liquid levels. In harp designs, the pipes are sloped so that the liquid drains toward the outlet.
- Gravity settling occurs as the gas flows to the vapor outlet on the top while the liquid flows out the bottom outlet.
- Pipe diameters are usually relatively small(usually less than 48 inches [120 cm]), so settling distances are short.

Inlet vessels

- These slug catchers, commonly called inlet receivers, are simply gas-liquid separators that combine slug catching with liquid storage.
- They are usually employed where operating pressures are relatively low or where space is a problem.
- Horizontal vessels are preferred, unless area is limited (as on offshore platforms), because they provide the highest liquid surface area.
- Usually two or three vessels are manifolded together to permit larger volumes and to allow servicing of one vessel without plant disruption. Length-to-diameter ratios are typically 3:1 to 5:1 to maintain a low gas velocity through the gravity-settling section.

Comparison of slug catcher configurations

- Land or surface requirements

  : If no land constraints apply, piping is attractive. If constraints are severe, as on offshore platforms, vertical vessels are preferred. Otherwise horizontal vessels are the best choice.

- Operating pressure.

  : If inlet pressures are greater than about 500 psi(35 bar), significant savings in material costs can be achieved by use of the smaller diameter piping slug catcher.

- Gas-liquid separation capability.

  : Horizontal vessels provide the best separation, whereas piping provides the least because its main function is to catch liquid slugs. The large liquid surface area of horizontal vessels provides the best degassing. Piping has the shortest gas residence time when liquid levels are properly maintained in the vessels. However, with piping, small diameter gas scrubbers can be used for demisting.

- Liquid storage.

  : Horizontal vessels can act as primary liquid storage, whereas liquids from vertical vessels and piping must be sent to another vessel. Regardless of slug catcher used, liquids will go to low-pressure flash drums to recover light ends.

Thank you!