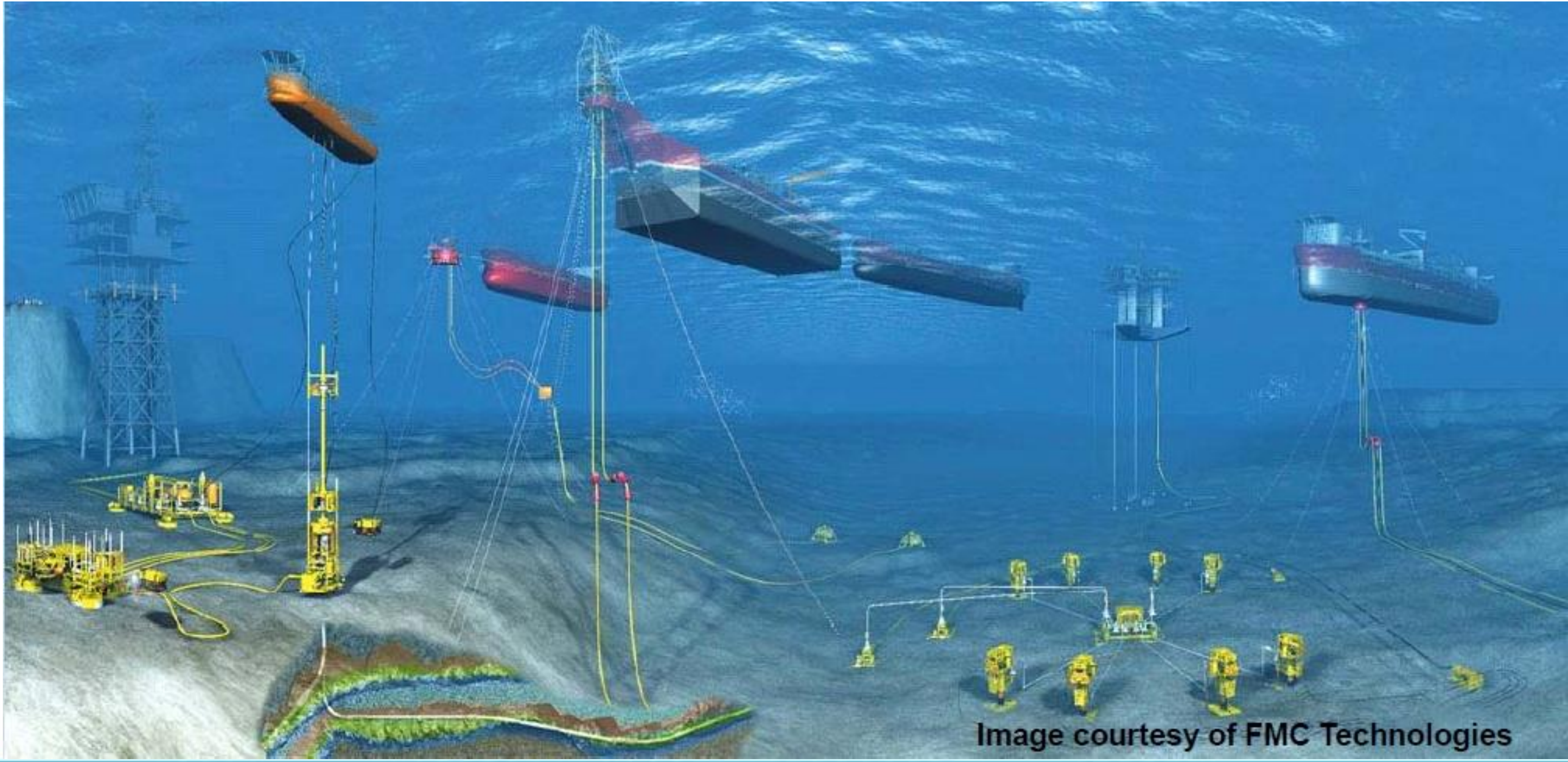


Introduction to Offshore Platform Engineering

Yutaek Seo

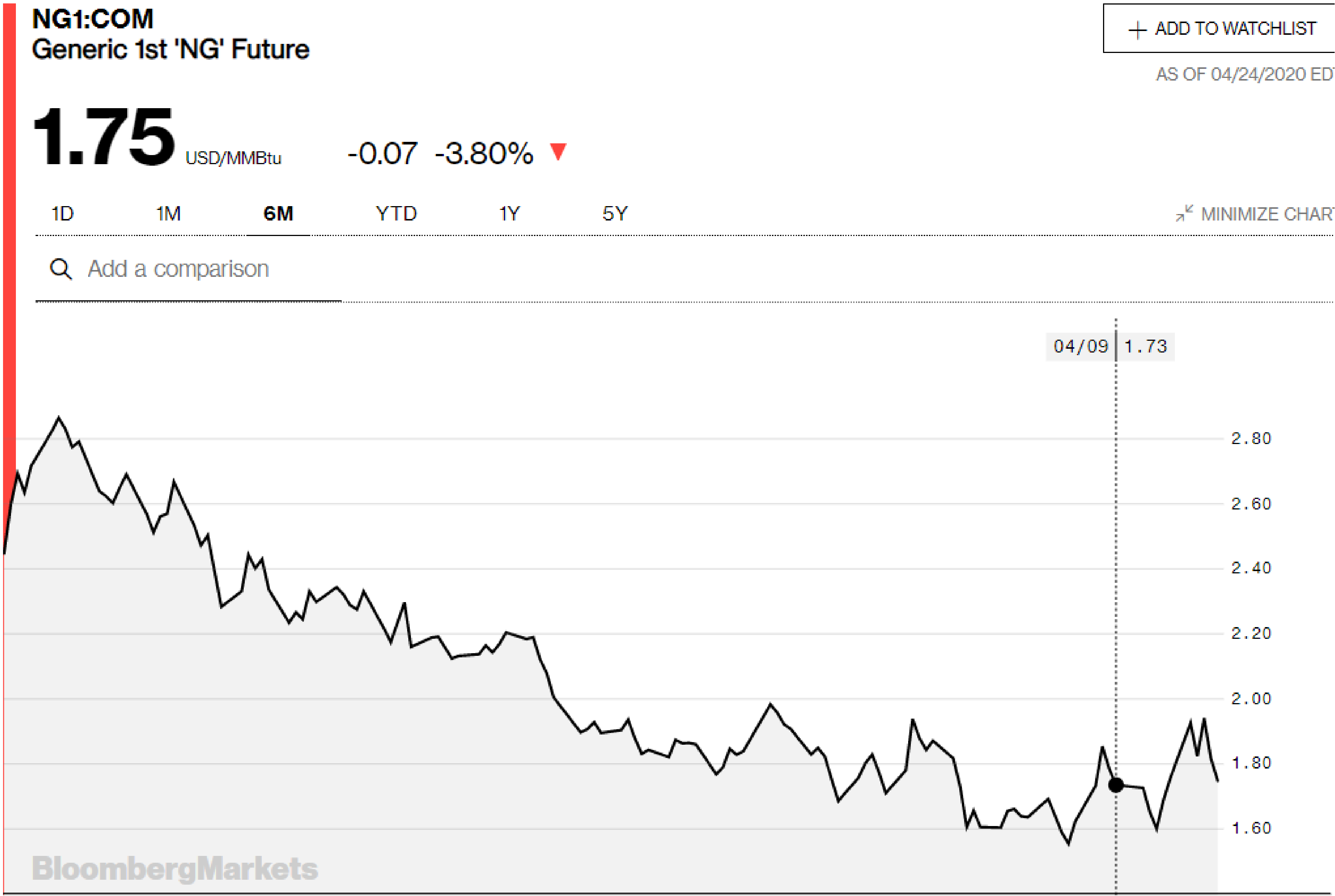
Crude Oil & Natural Gas

INDEX	UNITS	PRICE	CHANGE	%CHANGE	CONTRACT	TIME (EDT)
CL1:COM **WTI Crude Oil (Nymex)**	USD/bbl.	16.94	+0.44	+2.67%	Jun 2020	4/24/2020
CO1:COM **Brent Crude (ICE)**	USD/bbl.	21.44	+0.11	+0.52%	Jun 2020	4/24/2020
CP1:COM **Crude Oil (Tokyo)**	JPY/kl	20,750.00	+250.00	+1.22%	Sep 2020	4:30 PM
NG1:COM **Natural Gas (Nymex)**	USD/MMBtu	1.75	-0.07	-3.80%	May 2020	4/24/2020

Oil and Gas for Energy Mix
: Development options – FPSO vs pipeline

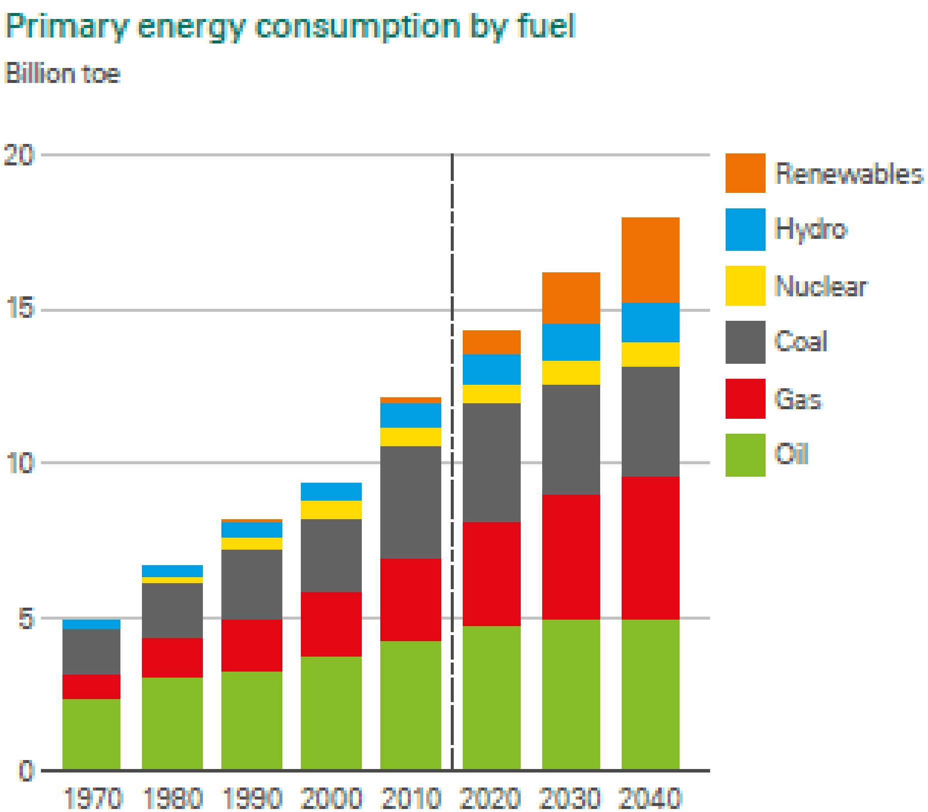
WTI Crude oil chart

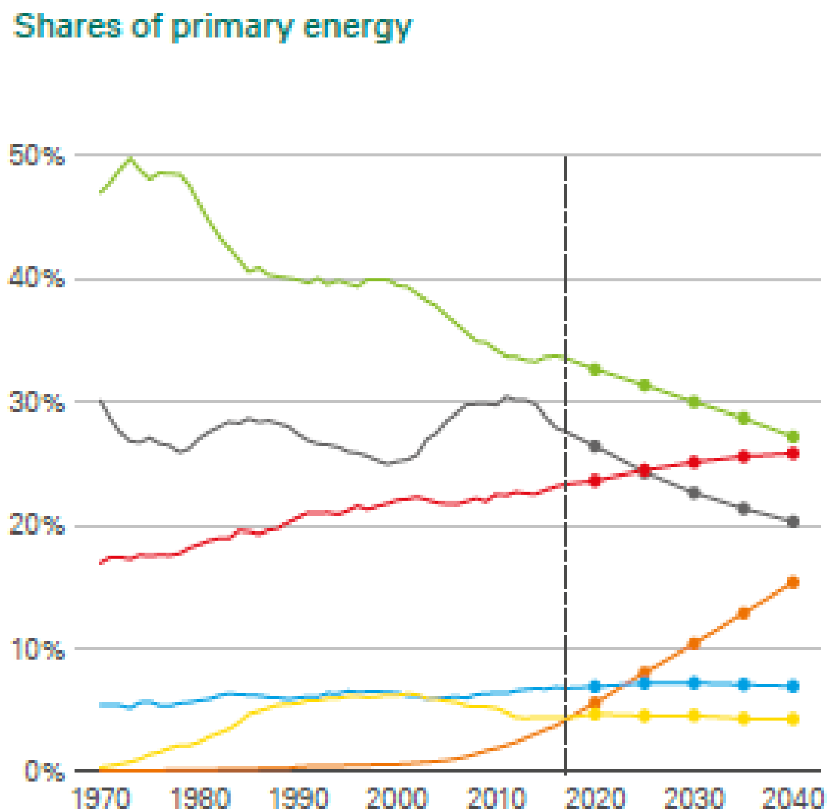
Natual gas chart



Energy mix in 2019 (BP Energy Outlook to 2040)

- The transition to a lower carbon fuel mix continues.





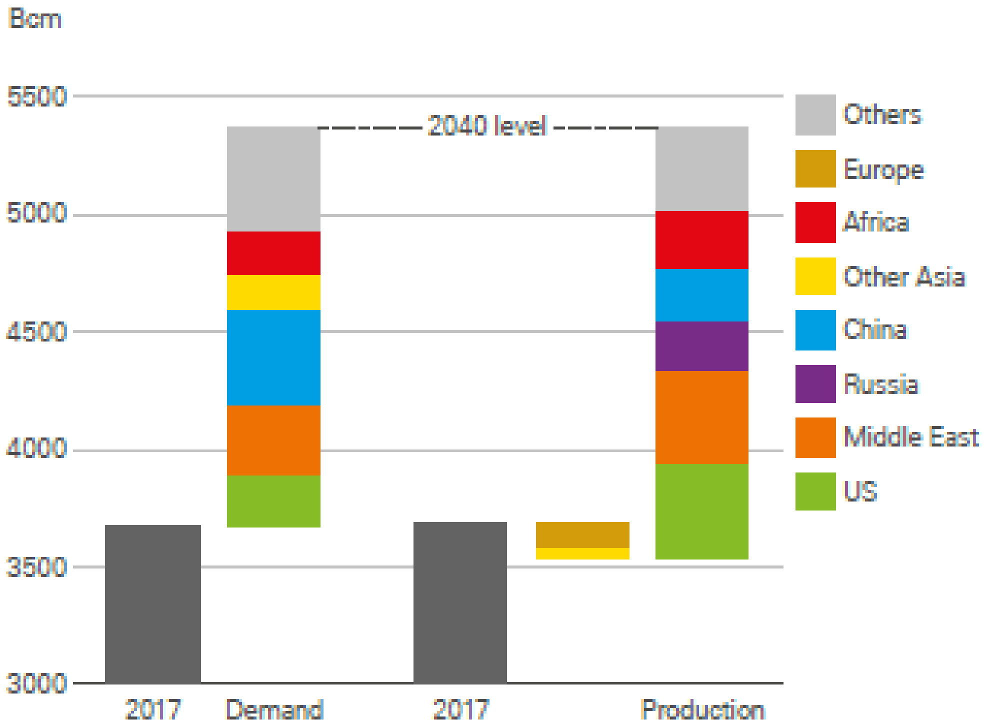
Transition to lower carbon fuel mix

- The transition to a lower-carbon energy system continues, with renewable energy and natural gas gaining in importance relative to oil and coal.
- In the ET scenario, renewables and natural gas account for almost 85% of the growth in primary energy, with their importance increasing relative to all other sources of energy.
- Renewable energy (7.1% p.a.) is the fastest growing source of energy, contributing half of the growth in global energy, with its share in primary energy increasing from 4% today to around 15% by 2040.
- Natural gas (1.7% p.a.), grows much faster than either oil or coal, overtaking coal to be the second largest source of global energy and converging on oil by the end of the Outlook.
- Oil (0.3% p.a.) increases during the first half of the Outlook, although much slower than in the past, before plateauing in the 2030s.
- Coal consumption (-0.1% p.a.) is broadly flat over the Outlook, with its importance in the global energy system declining to its lowest level since before the industrial revolution.

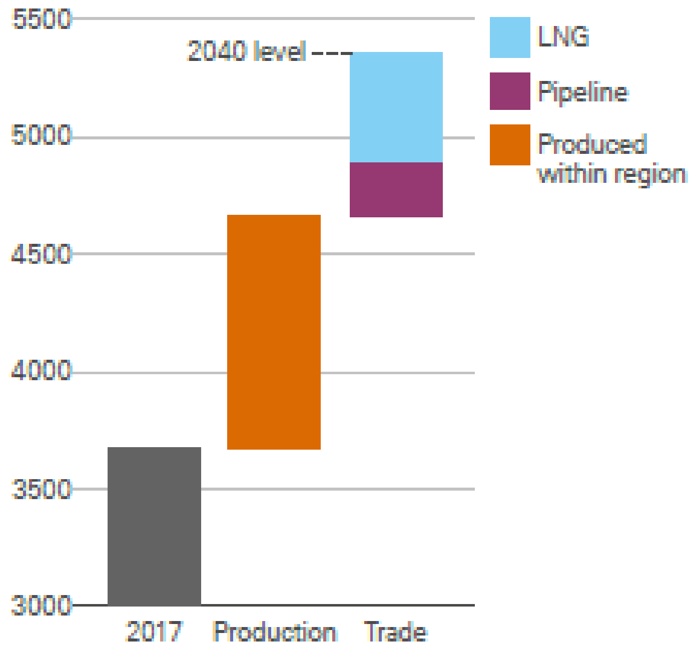
Natural gas outlook

- Natural gas grows strongly, with broad-based demand low-cost supplies and increasing global availability.
- Gas demand grows in almost every country and region considered in the outlook.

Gas demand and production, 2017-2040



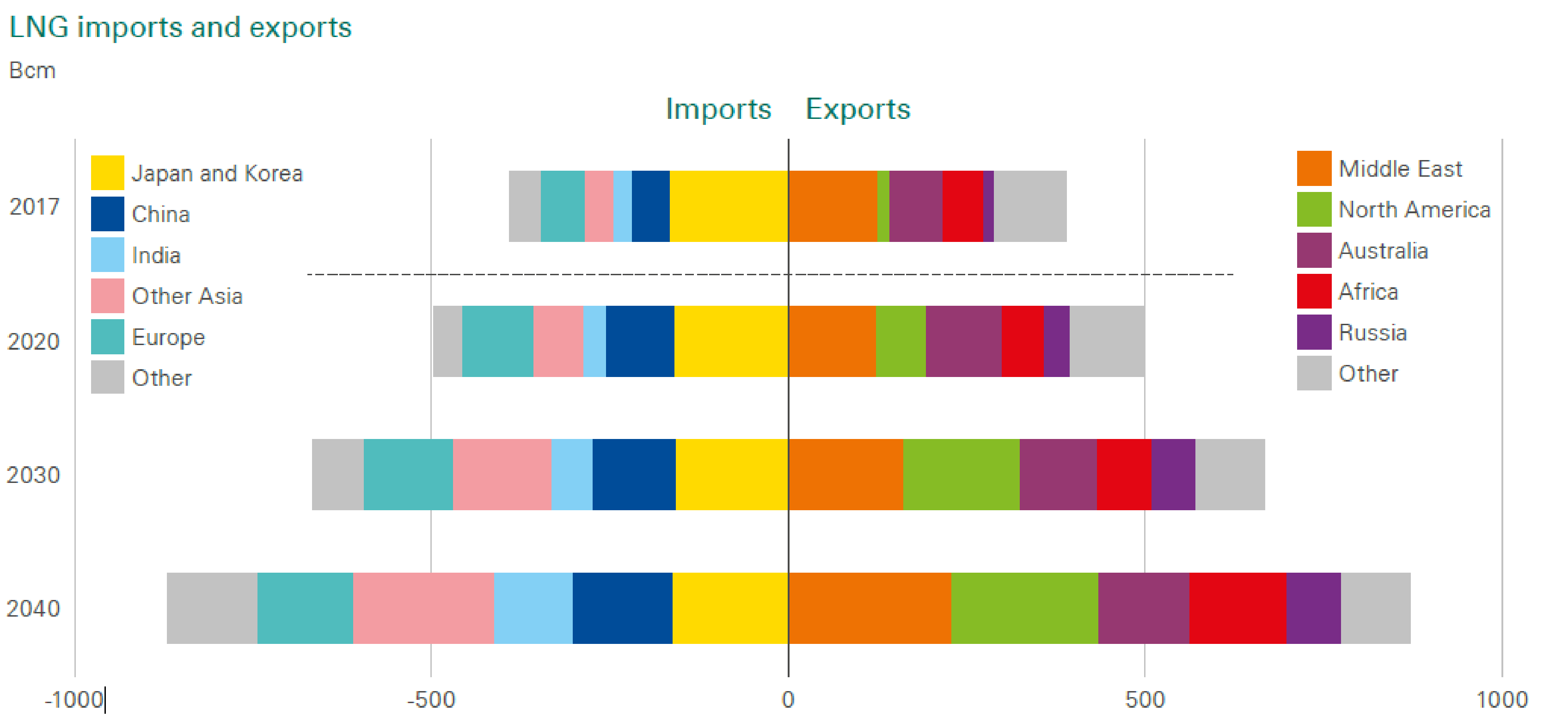
Gas trade, 2017-2040



- Natural gas grows strongly, supported by broad-based demand, plentiful low-cost supplies, and the increasing availability of gas globally, aided by the growing supplies of liquefied natural gas (LNG).
- In the ET scenario, natural gas grows at an average rate of 1.7% p.a. - increasing nearly 50% by 2040 - the only source of energy, along with renewables, whose share in primary energy increases over the Outlook.
- Growth in gas demand is widespread, increasing in almost every country and region considered in the Outlook. The increase is driven in broadly equal amounts by use in power and industry. Transport records the fastest growth, albeit with small volumes.
- Global gas production is led by the US and Middle East (Qatar and Iran) – who together account for almost 50% of the growth in gas production over the Outlook – supported by strong increases in output in both China and Russia.
- The importance of gas trade continues to grow over the Outlook, driven by robust expansion of LNG supplies which account for more than 15% of total gas demand in 2040, overtaking inter-regional pipeline shipments in the late 2020s.

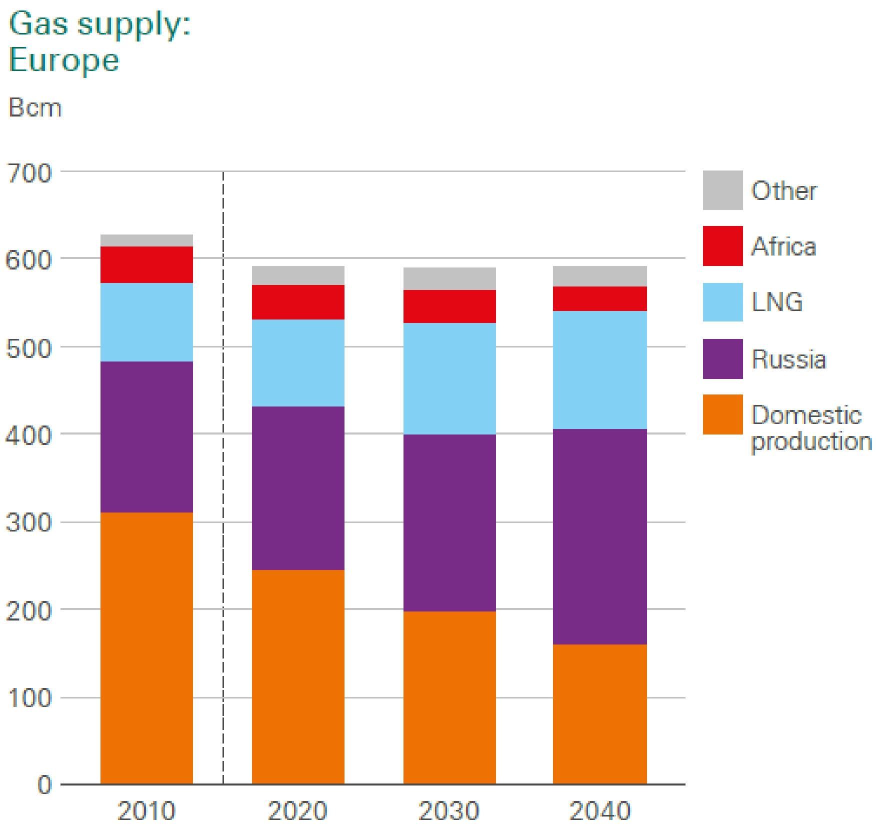
LNG trades

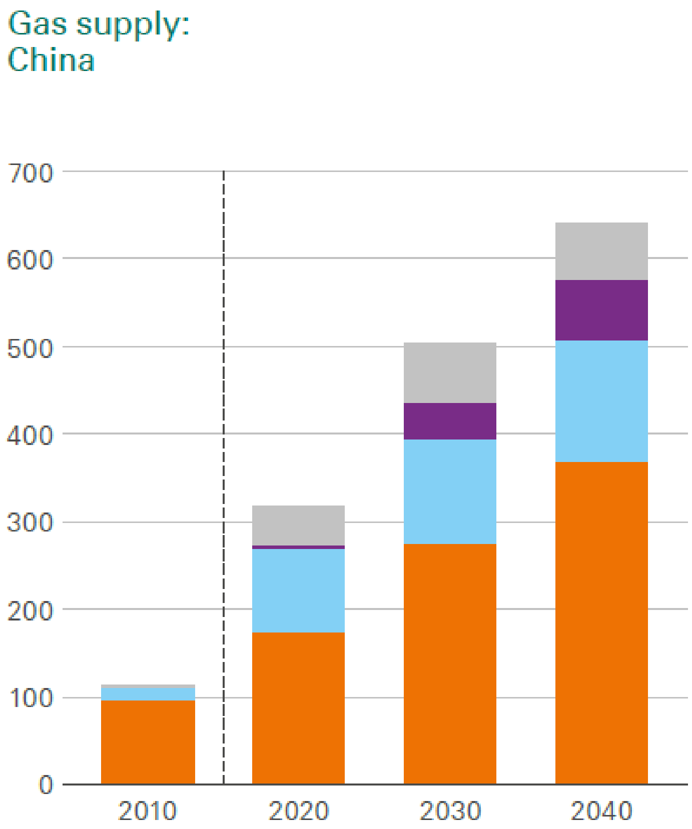
- LNG exports increase significantly, led by US and Qatar, fostering a more competitive and globally-integrated market.
- Global LNG volumes are set to expand substantially, leading to a more competitive, globally integrated gas market.
- In the ET scenario, LNG trade more than doubles, reaching almost 900 Bcm in 2040 up from around 400 Bcm in 2017.



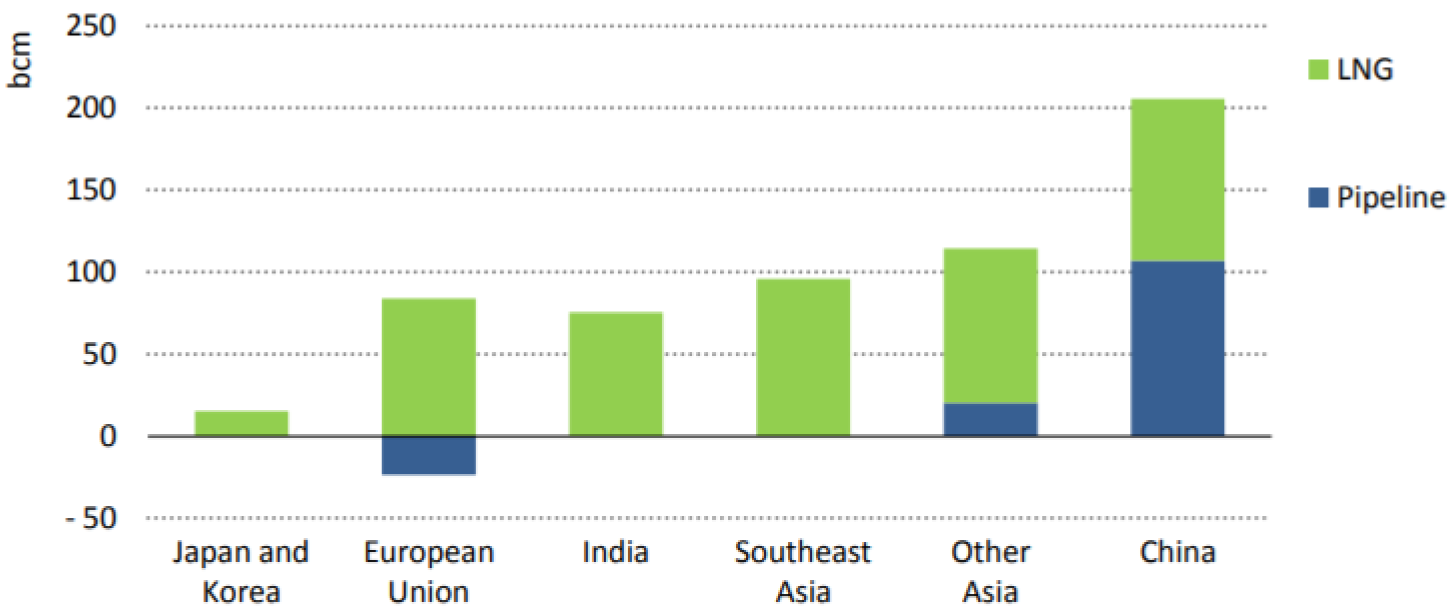
- The increase in LNG exports is led by North America, followed by the Middle East, Africa and Russia. As the LNG market matures, the US and Qatar emerge as the main centres of LNG exports, accounting for around 40% of all LNG exports by 2040.
- Asia remains the dominant market for LNG imports, although the pattern of imports within Asia shifts, with China, India and Other Asia overtaking the more established markets of Japan and Korea, and accounting for around half of all LNG imports by 2040.
- Europe remains a key market, both as a ‘balancing market’ for LNG supplies and a key hub of gas-on-gas competition between LNG and pipeline gas (see pp 100-101).
- The precise profile of LNG volume growth will depend on the timing and availability of the new investments needed to finance the considerable expansion. The cyclical nature of LNG investments means there is a risk that the development of the LNG market will continue to be associated with periods of volatility.

- The increasing diversity of gas exports leads to greater competition between LNG and pipeline gas, especially in Europe and China – two of the largest importers of gas.



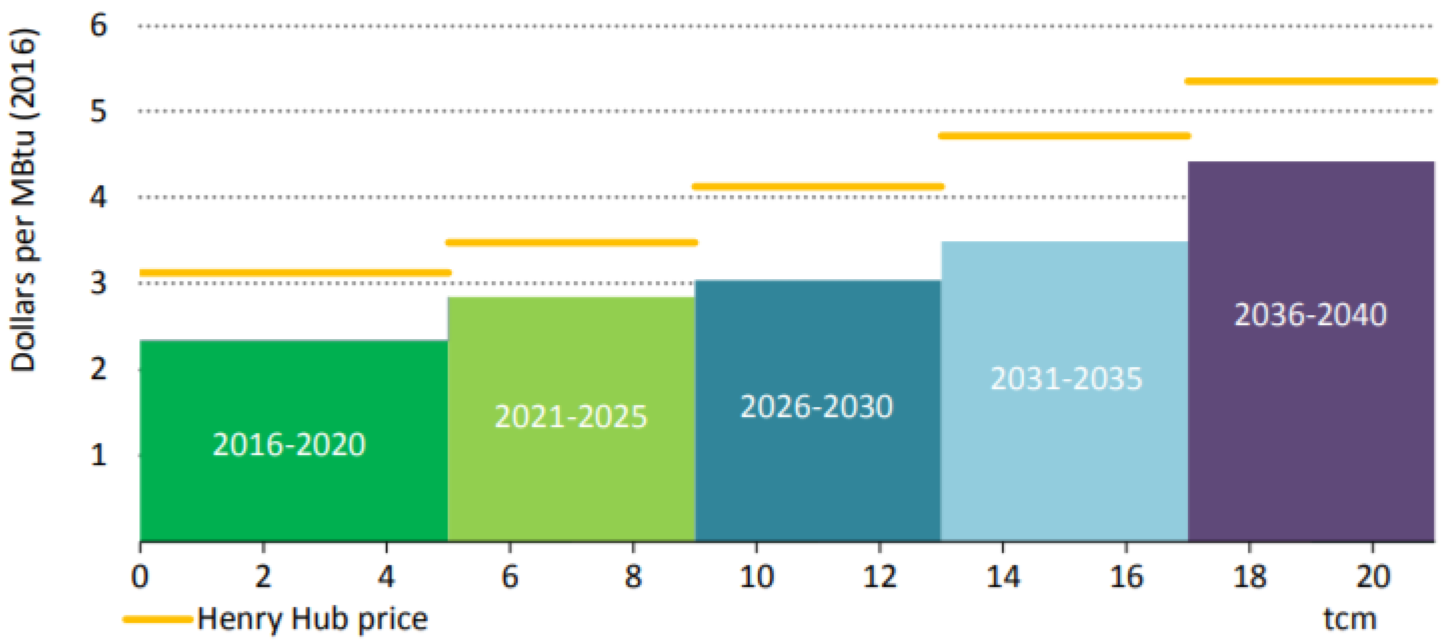


- The countries that have good domestic gas production prospects will rely on the existing and newly-built pipeline infrastructure.
- Asian countries lead the growth in global gas trade; outside china, new pipeline trade routes find it hard to advance in a market with LNG readily and flexibility available, such countries as Malaysia, Thailand, Pakistan, and Bangladesh.
- There will be gas-on-gas competition between LNG and pipeline gas.

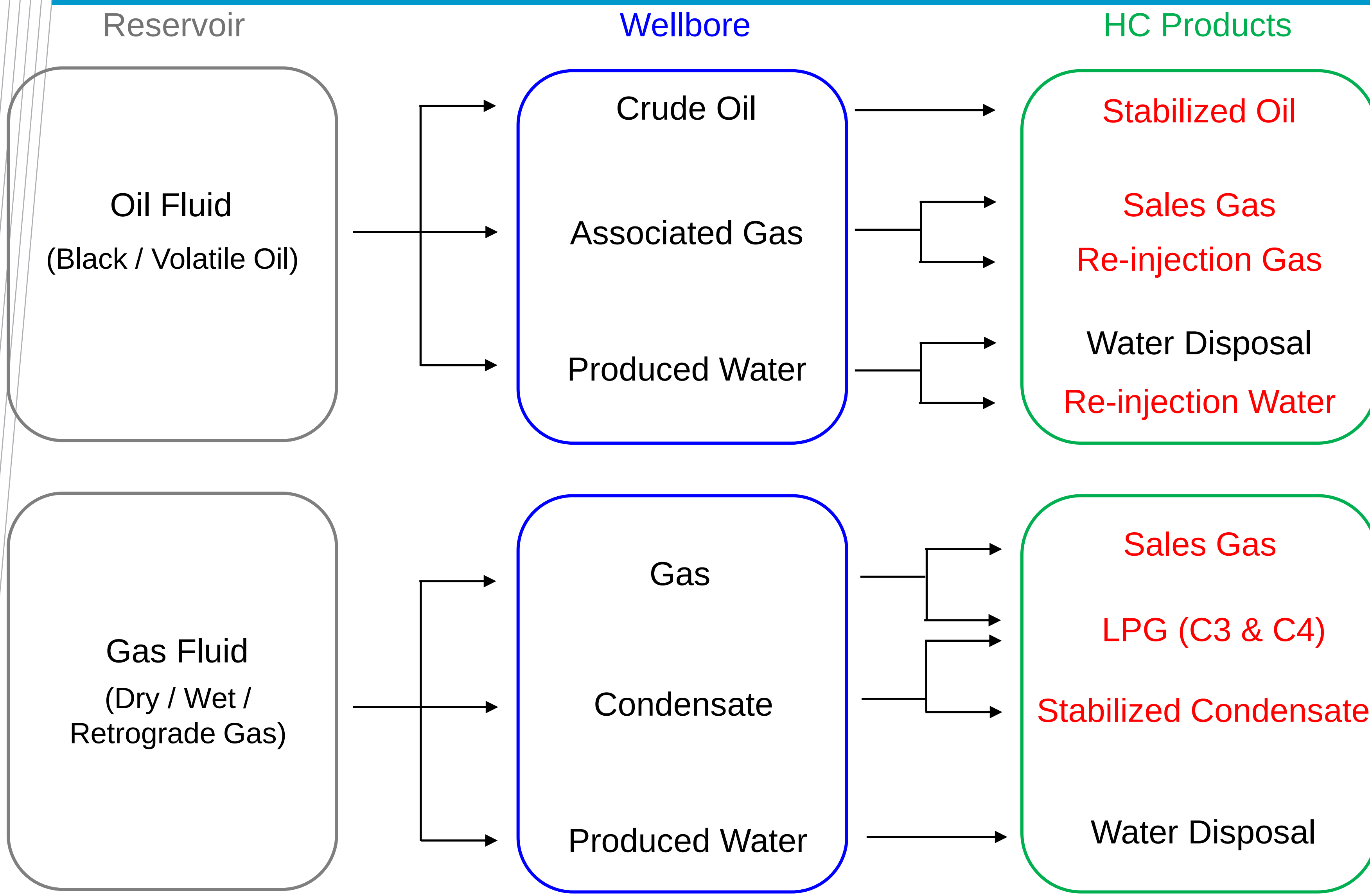


Rising costs of gas resources

- The availability of relatively low cost gas and the resource estimate has led to a more optimistic assessment of the size and number of sweet spots, i.e. the economically most attractive portions of a gas deposit.
- Nonetheless, producers are forced gradually to move away from the sweet spots to less productive zones. Continued technology learning and innovation mitigate the effect of this move on the economics of gas development.
- Overall, however, the cost of new resources developed gradually increases and puts upward pressure on gas prices.



Form Reservoir To Products



Processing in offshore platforms

Oil FPSO

- FPSOs are large ships equipped with processing facilities and moored to a location for a long period.

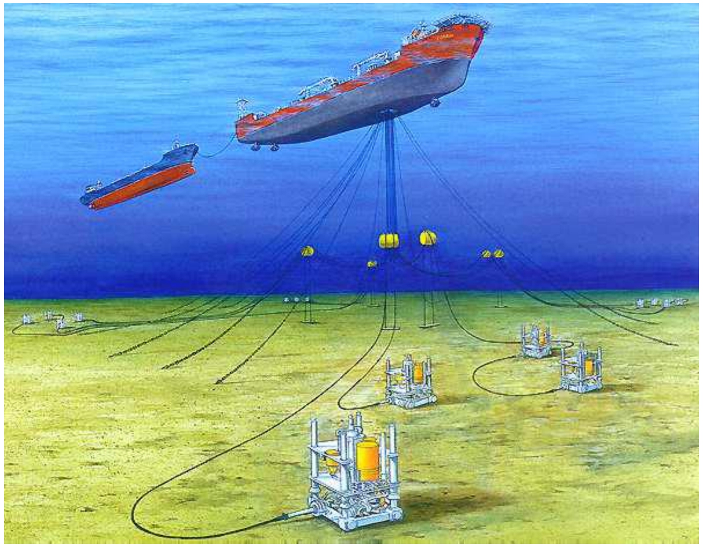
The main types of floating production systems are:

FPSO(floating production, storage, and offloading system),

FSO (floating storage and offloading system), and

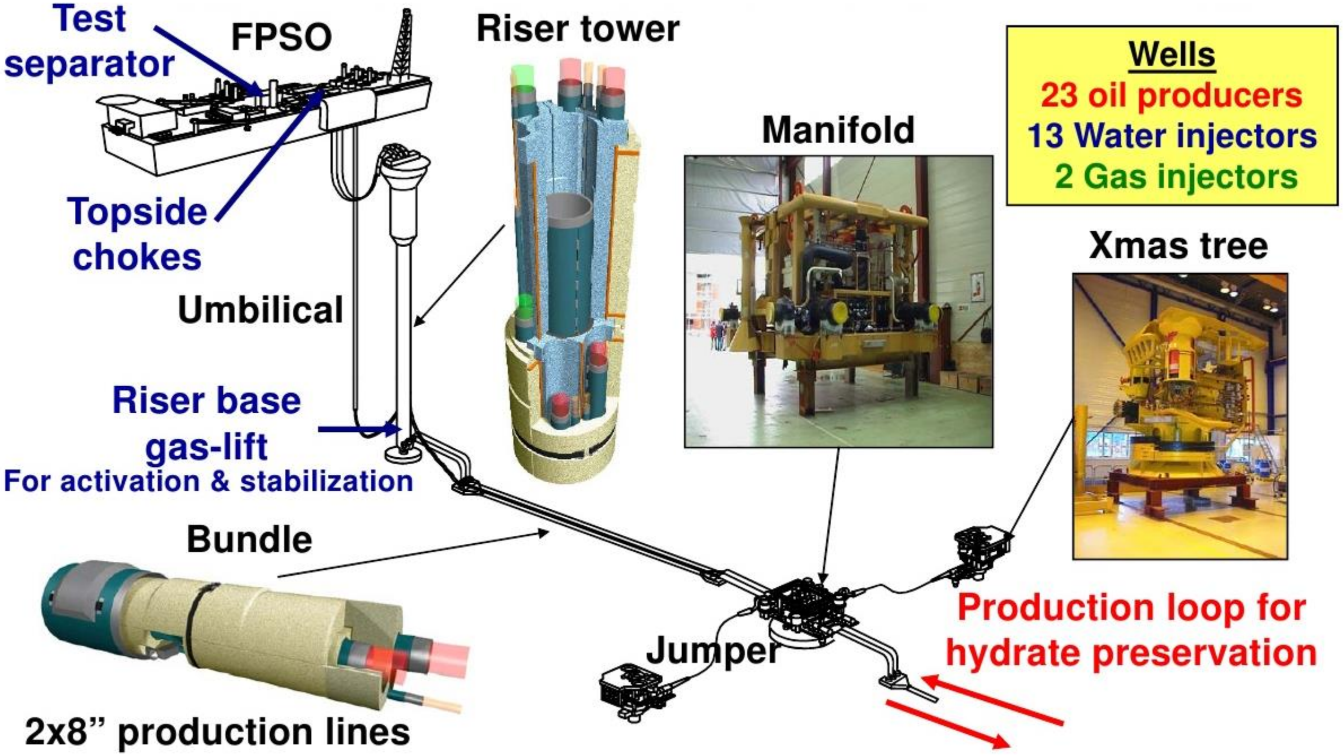
FSU (floating storage unit).

- These ships do not actually drill for oil or gas.



FPSO in West Africa

- Girassol (TotalFinaElf)
  - : Located of NNW Luanda, Angola - 1350m of water
  - : Producing 32º API crude oil from 23 wells
  - : Total storage capacity 2 million bbl of crude oil
  - : Liquid processing 180,000 bpd
  - : 3 million m^3/d gas lift with 8 million m^3/d gas compression and dehydration



FPSO in Western Australia

- **Vincent oil field**

  : Located offshore Exmouth in Western Australia

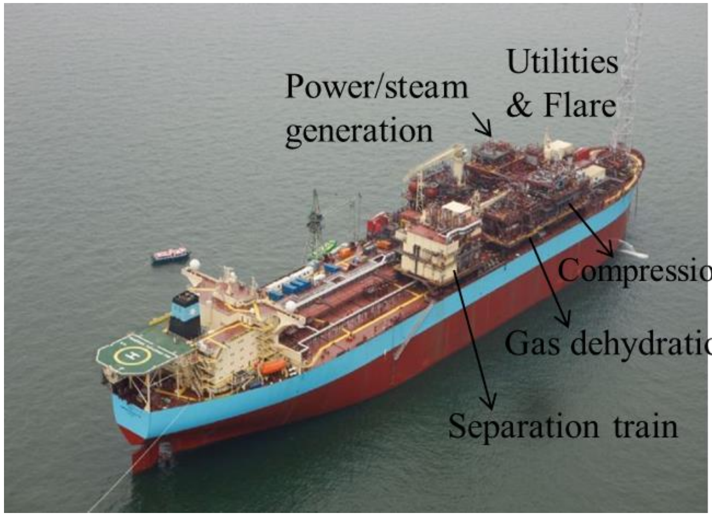
  : Water depth 350m, 17^{o} API crude from 8 wells

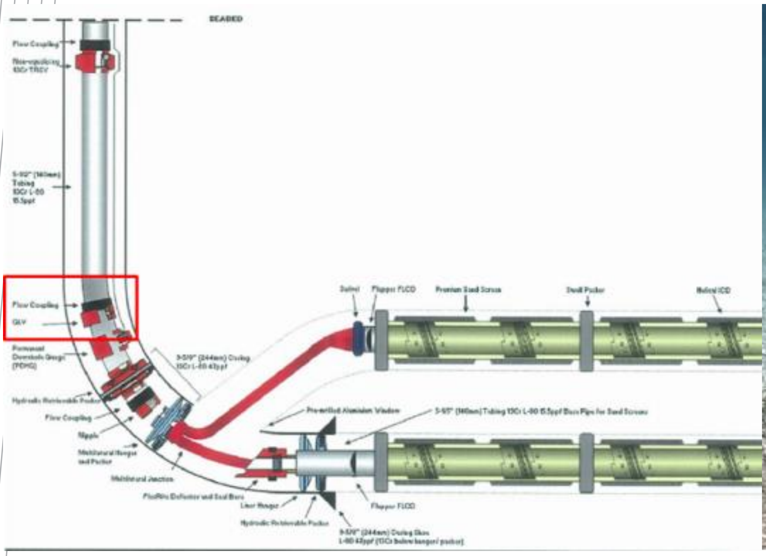
  : Oil column thickness 8.5 ~ 19.0 m

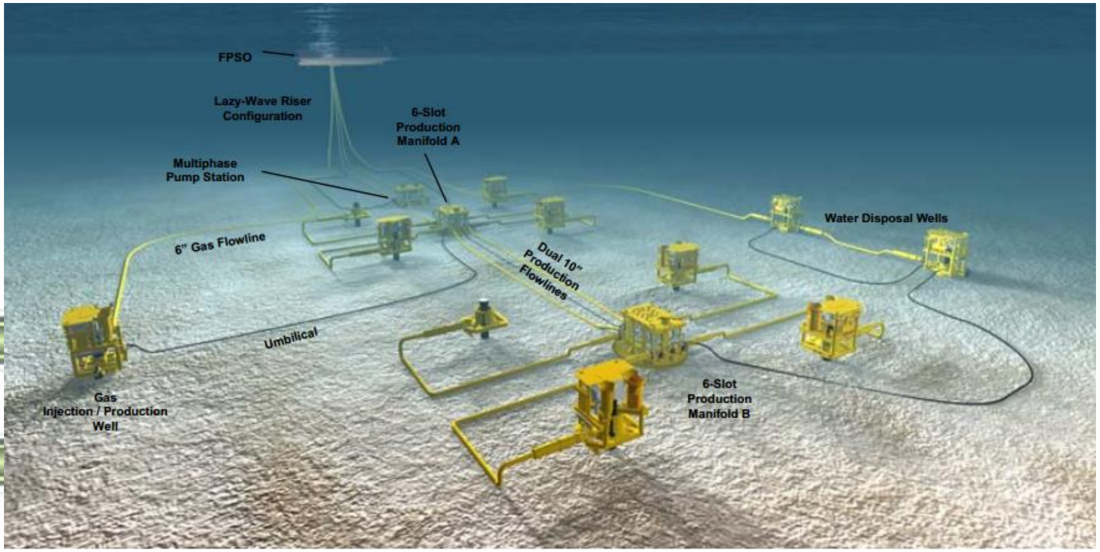
  : Total Liquid processing capacity 120,000 b/d with total storage capacity of 1.2 million barrels of oil

  : Water (150,000 b/d) & Gas (80 MMscf/d) Injection

  : Dual sided hull and disconnectable mooring

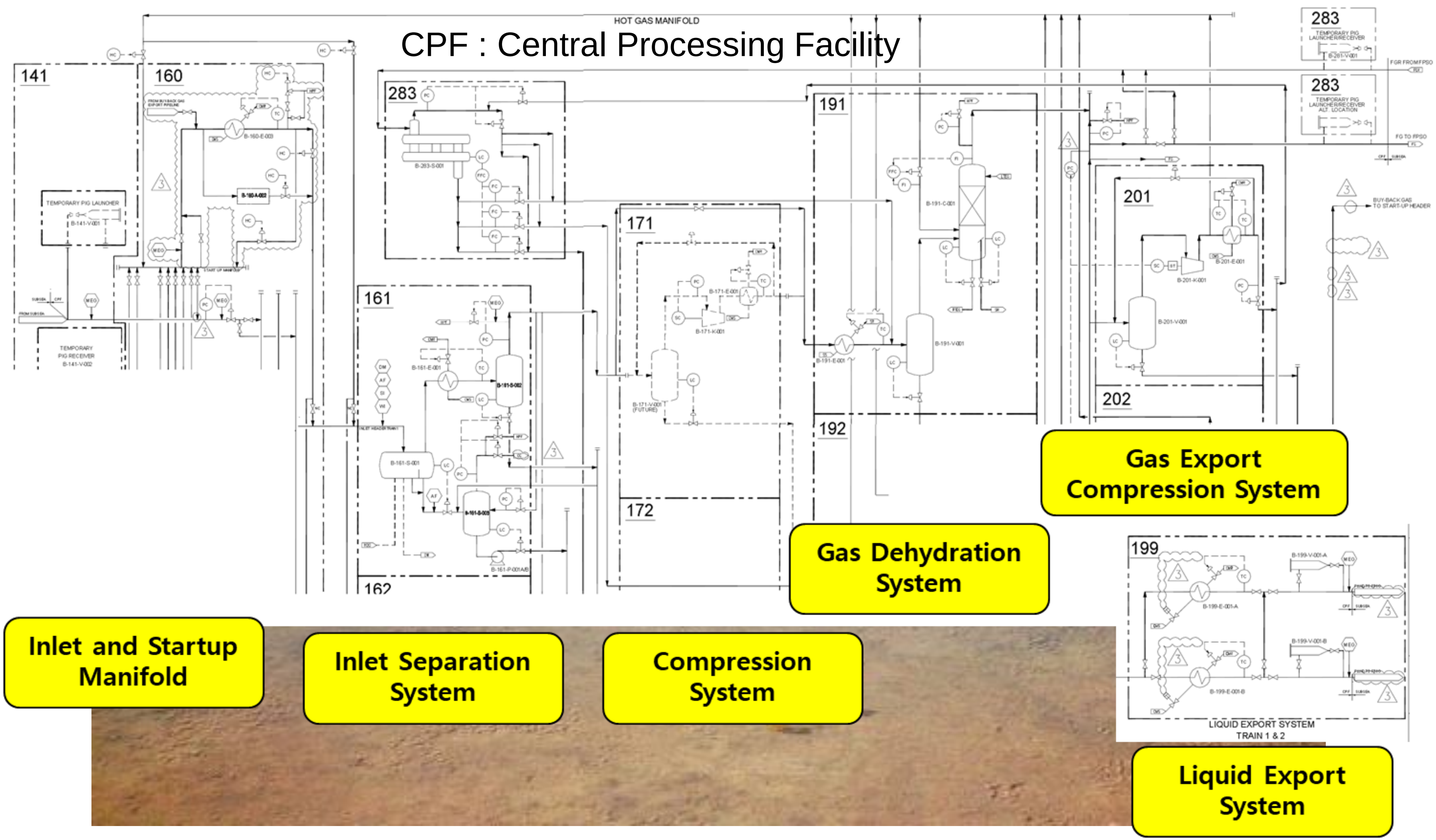




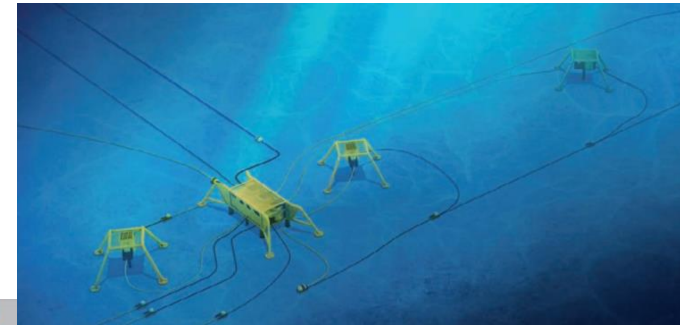


Gas Platform

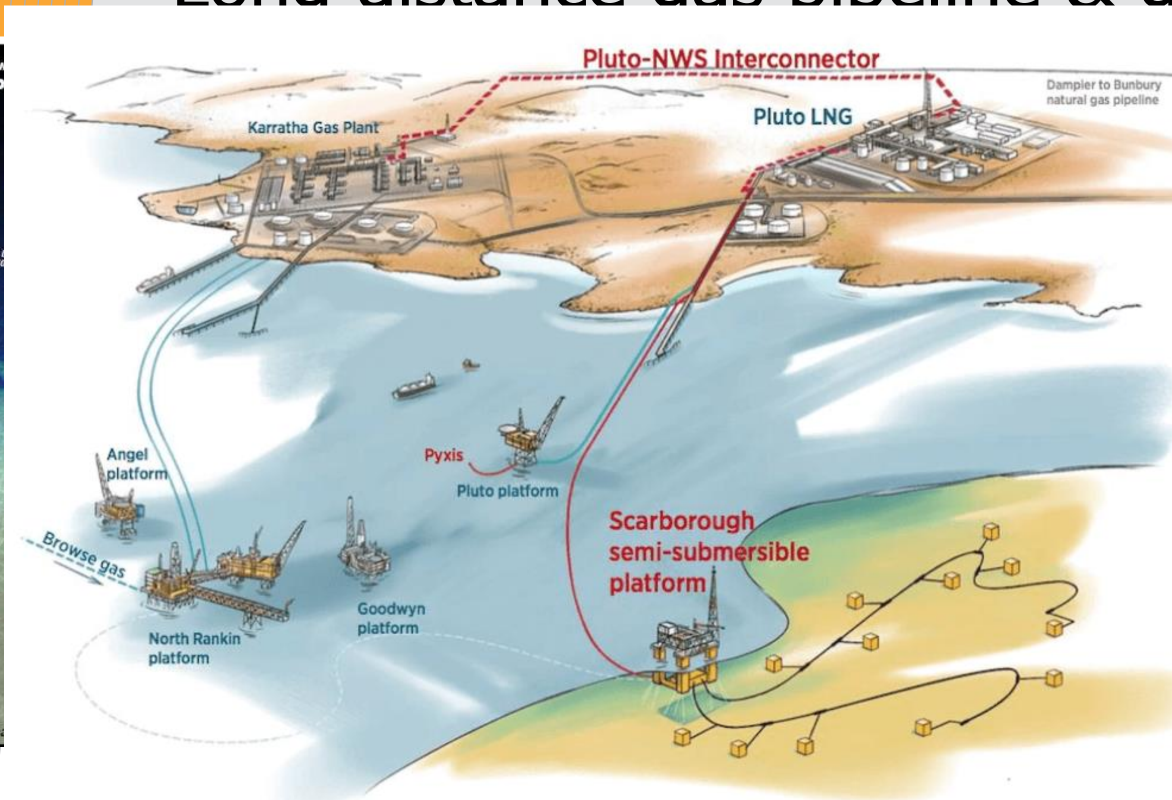
Ichthys Gas / Condensate production platforms for Darwin LNG Project

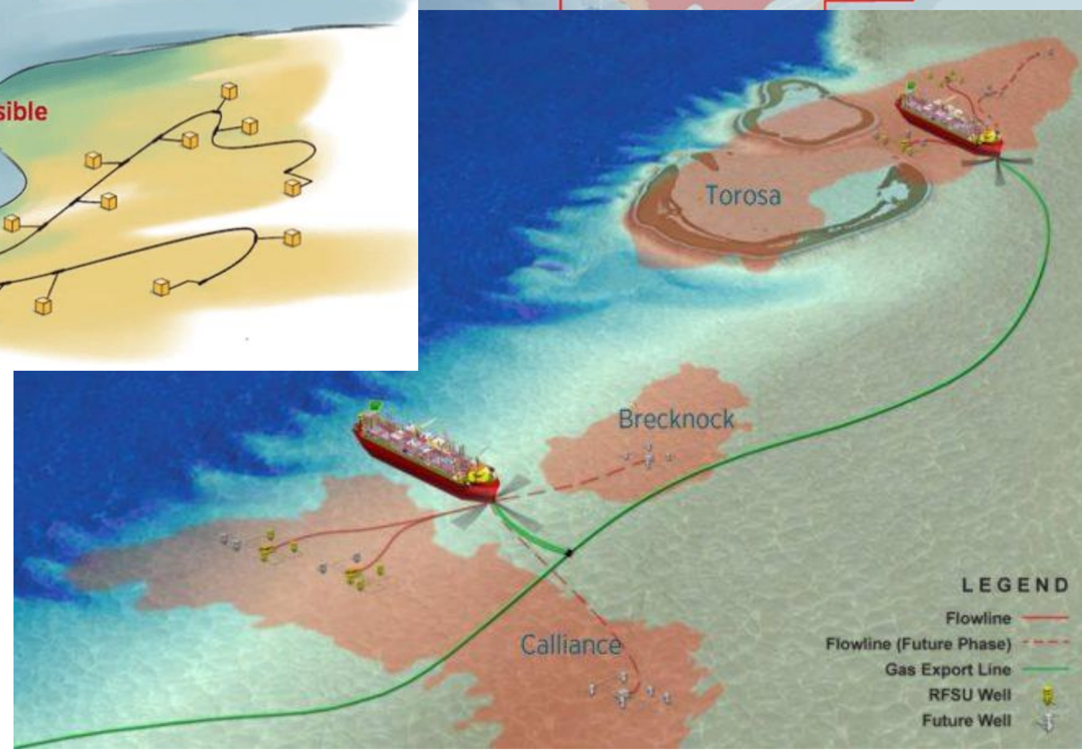


Sakhalin gas pipeline – long distance transport



Long distance gas pipeline & gFPSO



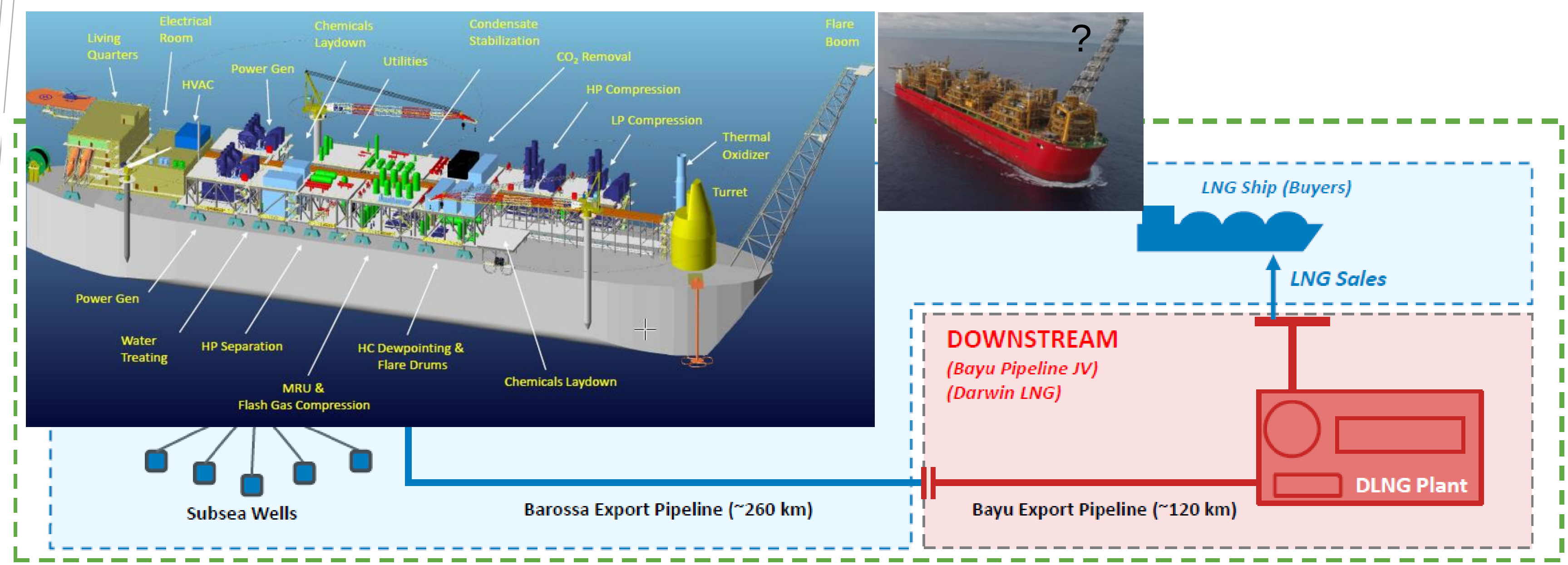


- Woodside is leaning towards the development using two gas Floating Production Storage and Offloading Units (gFPSO) delivering around 10 mtpa of gas to NWS infrastructure by an approximately 900 km pipeline. (2018. 10. 11)

gFPSO (gas-only FPSO)

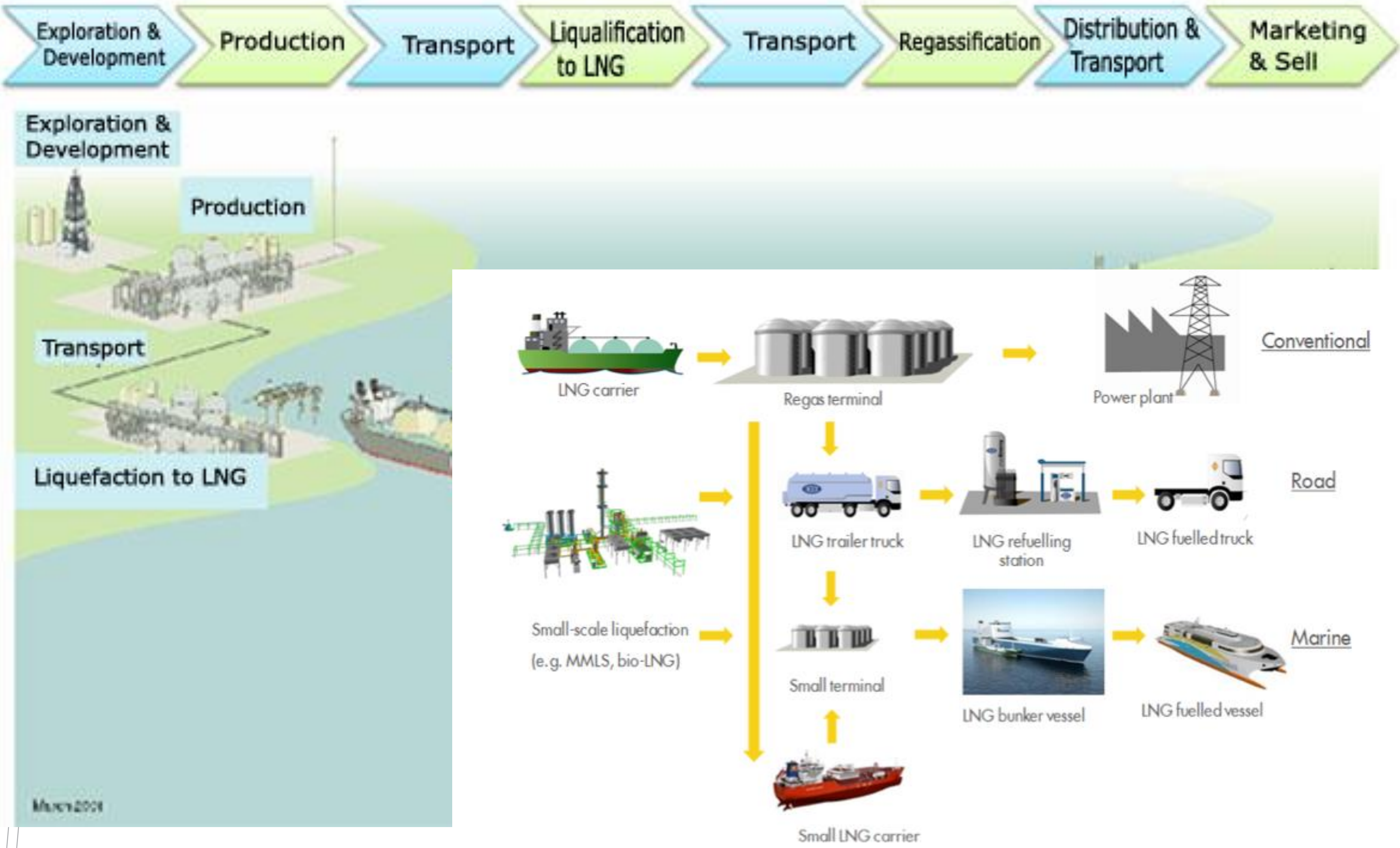
- A GFPSO would essentially be a floating gas production and conditioning facility. Principal export products from a GFPSO would be a LPG liquid, a C5+ condensate liquid and pipeline quality residue gas.
- Technip FMC has developed gas FPSO (Barossa, Tortue and Abadi projects) which is an alternative to FLNG to develop stranded offshore gas fields to export gas for feeding either existing new onshore LNG plants or domestic market.

  : From lean to rich gas (LPG can also be produced)
  : Capability and Knowledge to process any feed gas flow characteristics
  : HSE design capacity to propose mixed solutions (safety gaps, fire walls)



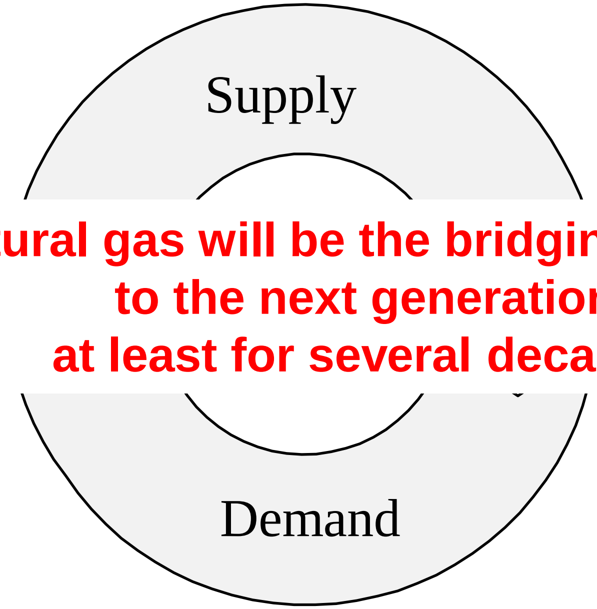
LNG transportation

LNG value chain



Benefit of natural gas?

- Sufficient reserves: onshore and offshore
- New solutions to non-conventional gas development (FPSO, Shale gas production)



Natural gas will be the bridging energy to the next generation at least for several decades

- Greener: Less CO_2
- Less polluting: Negligible NOx, No SOx, No PM
- More economical: Cheaper than crude-driven fuels

Natural gas reserves

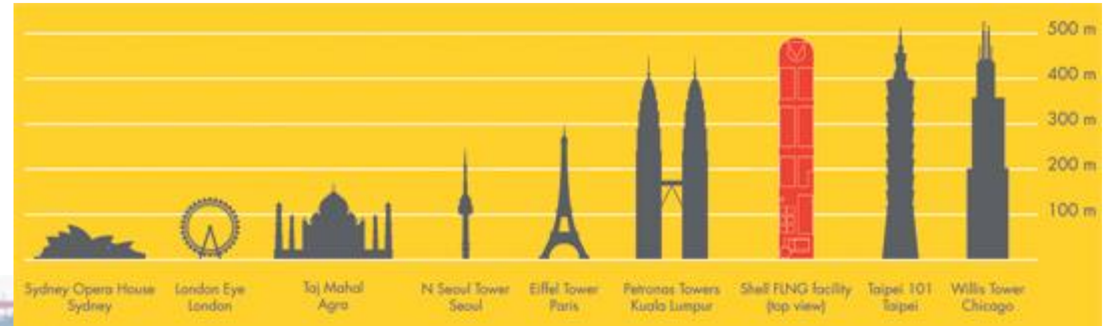
- Remaining technically recoverable natural gas resources by type and region, end-2016 (tcm).

	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
North America	51	11	61	7	79	130	12
Central & South America	28	15	41	-	56	84	8
Europe	19	5	18	5	28	47	5
Africa	51	10	40	0	50	101	17
Middle East	103	9	11	-	20	123	80
Eurasia	134	10	10	17	38	172	74
Asia Pacific	45	21	53	21	94	139	20
World	432	82	233	50	365	796	216

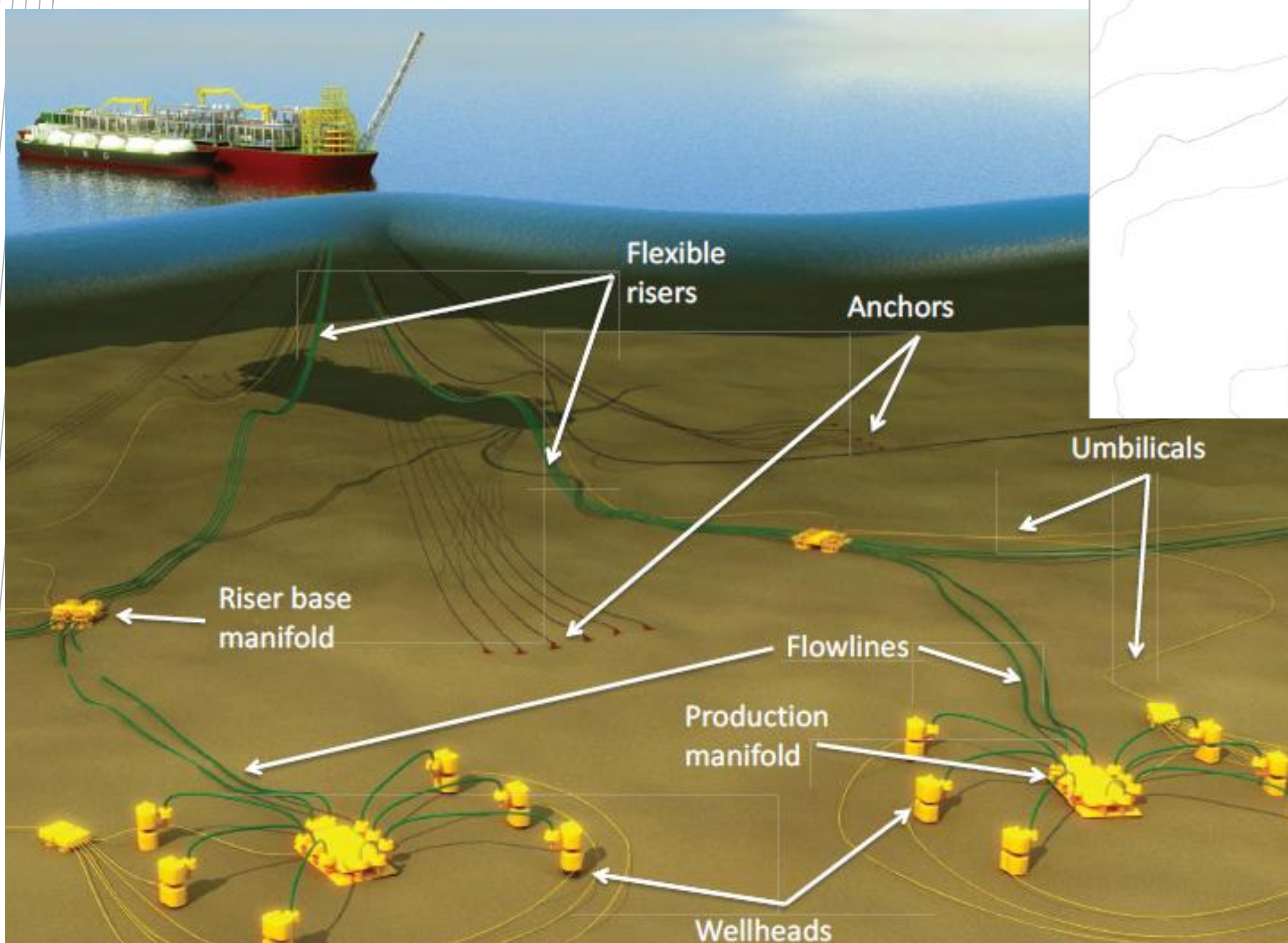
Sources: BGR (2016); BP (2017); Cedigaz (2017); OGJ (2016); US DOE/EIA/ARI (2013); US DOE/EIA (2017); USGS (2012a, 2012b); IEA databases and analysis.

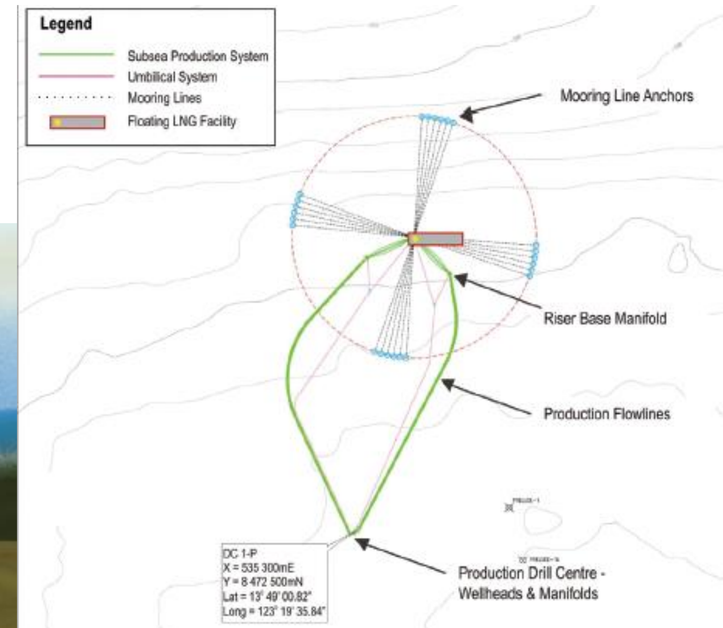
- Production of natural gas expands globally by 1,685 bcm over the next 25 years, reaching over 5,300 bcm in 2040. The United States, Russia and Iran are the three largest gas producers today.

Prelude FLNG

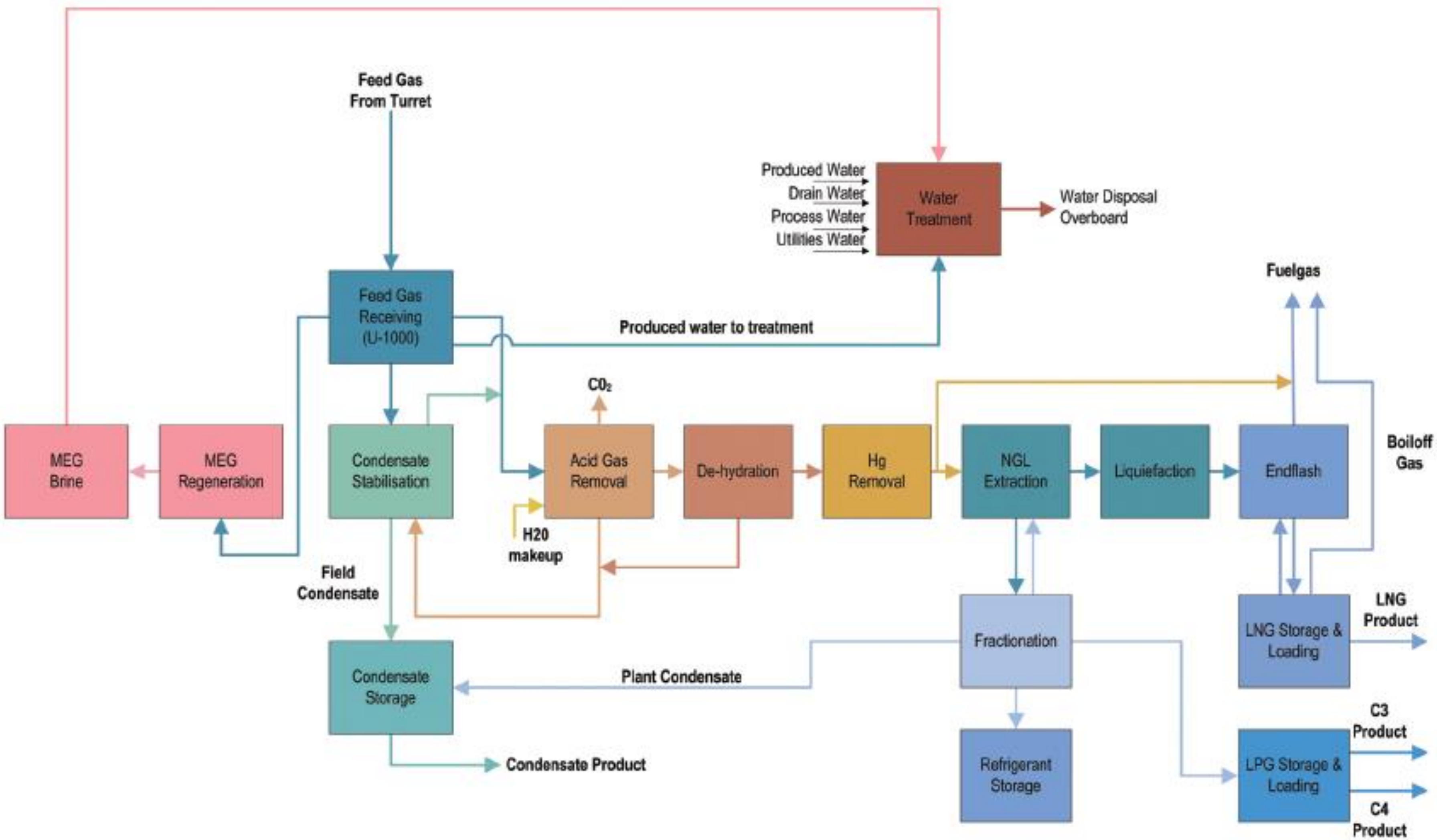


Prelude FLNG in operation



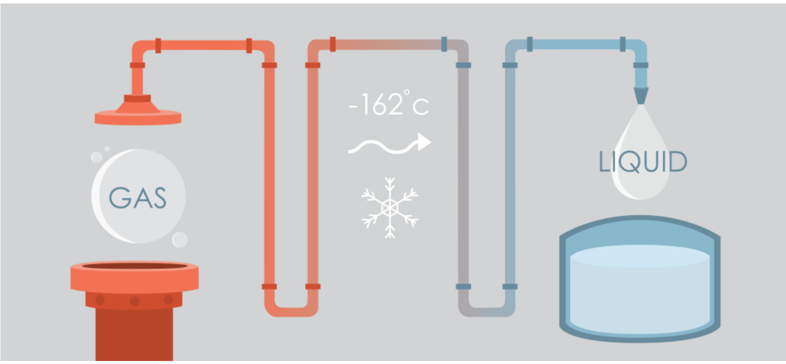


FLNG process overview

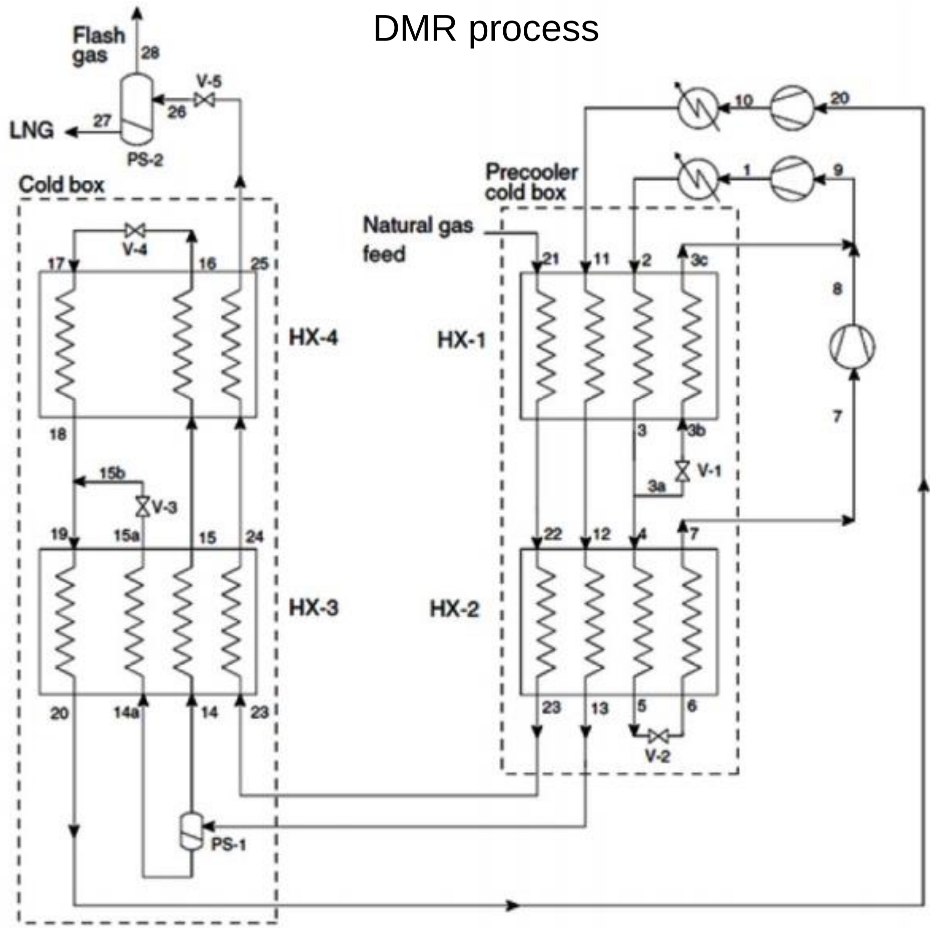


LNG (Liquefied Natural Gas)

- LNG is liquefied natural gas for easy transportation and storage.
- Volume ratio between LNG and natural gas is 1/600 at - 162°C, 1 atm.



Chemical	Chemical Formula	Low	High
Methane	CH_4	87%	99%
Ethane	C_2H_6	<1%	10%
Propane	C_2H_8	>1%	5%
Butane	C_4H_{10}	>1%	>1%
Nitrogen	N_2	0.1%	1%
Other Hydro-carbons	Various	Trace	Trace



DMR process

LNG Properties

- LNG is liquefied natural gas for easy transportation and storage.
- Volume ratio between LNG and natural gas is 1/600 at - 162^{o}C, 1 atm.
- Due to its low temperature, it must be treated as “Cryogenic liquid” requiring special equipment and procedures.
- Contacting cryogenic LNG induces fast cooling and loss of both mechanical strength and functions. Special containment system has to be used for storage of LNG.
- LNG is colorless, odorless, no corrosion, non flammable, and non toxic.
- Specific LNG properties are as follows,
  - Composition
  - Boiling point
  - Density and specific gravity
  - Flammability
  - Flash point

LNG composition

- Natural gas composition may vary depending on the gas fields location and types of processing process.
- LNG production can be made from the natural gas composed of methane, ethane, propane, butane, and small amount of heavy hydrocarbons.
- Impurities include Nitrogen, Carbon dioxide, Hydrogen sulfide, and water. These impurities must be removed through the pretreatment process, increasing methane content more than 85 vol%.

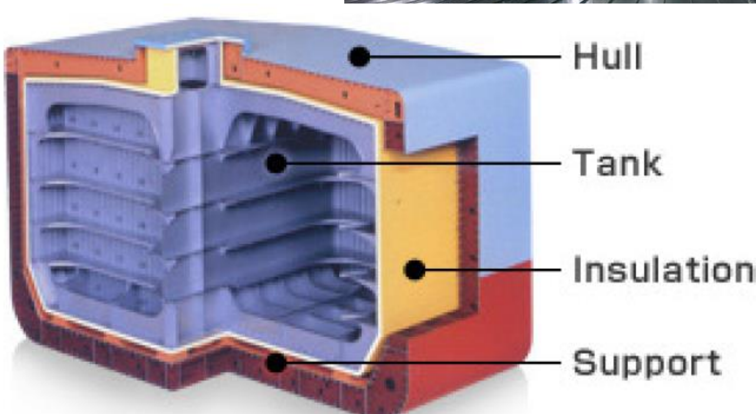
Chemical	Chemical Formula	Low	High
Methane	CH_4	87%	99%
Ethane	C_2H_6	<1%	10%
Propane	C_2H_8	>1%	5%
Butane	C_4H_{10}	>1%	>1%
Nitrogen	N_2	0.1%	1%
Other Hydro-carbons	Various	Trace	Trace

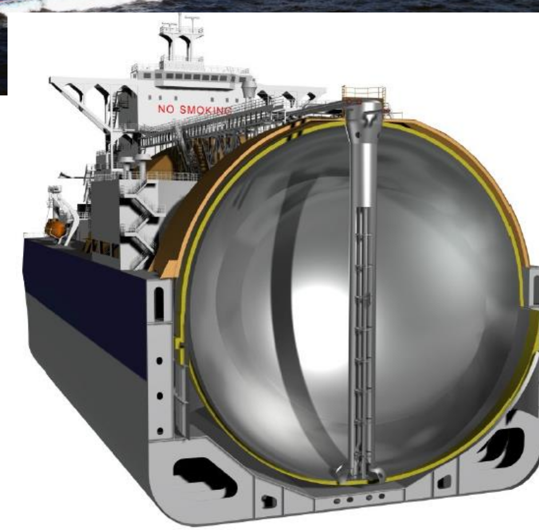
LNG boiling point, density & specific gravity

- LNG boiling point may change with natural gas composition, but normally is $-162^{o}C$ ($-259^{o}F$).
- When cryogenic LNG is exposed to warm air or water, LNG start to boil on the surface.

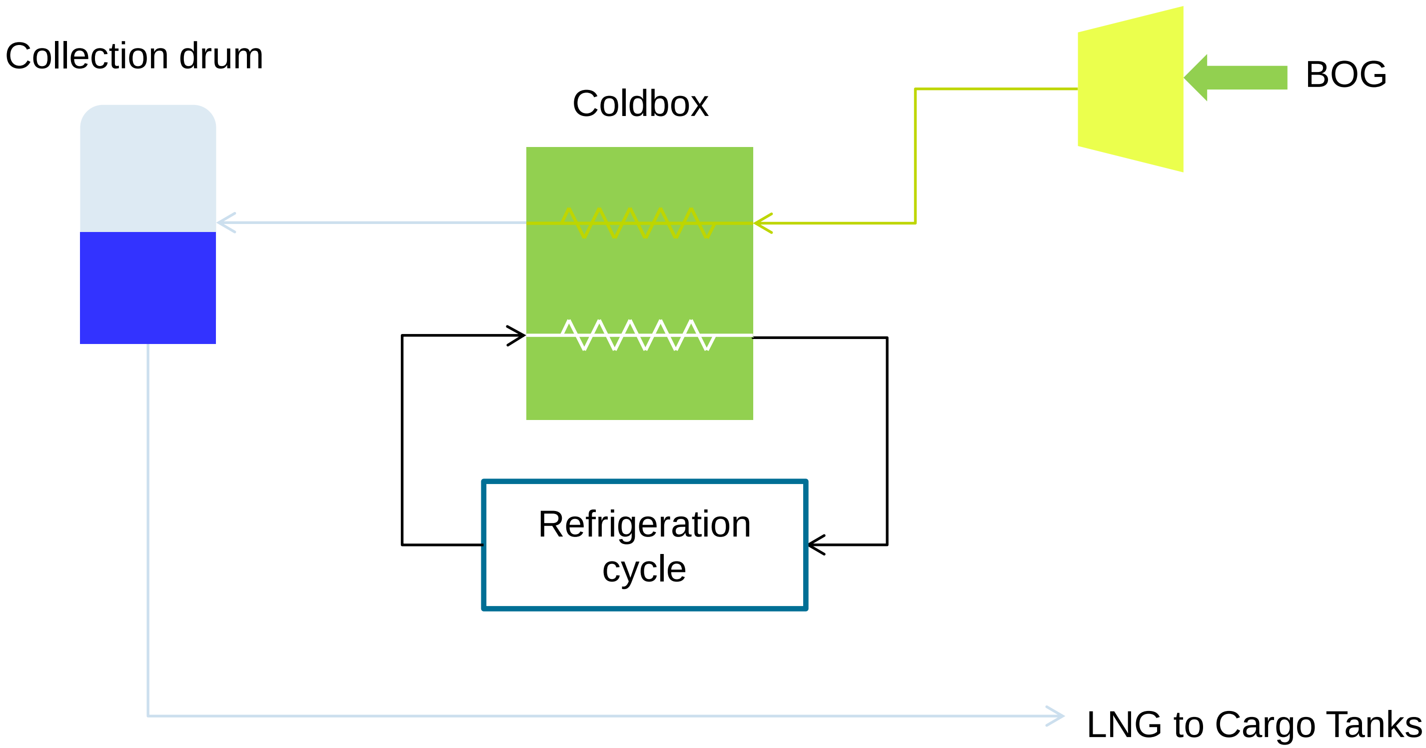
LNG Carrier

- Which type of tanks in it?



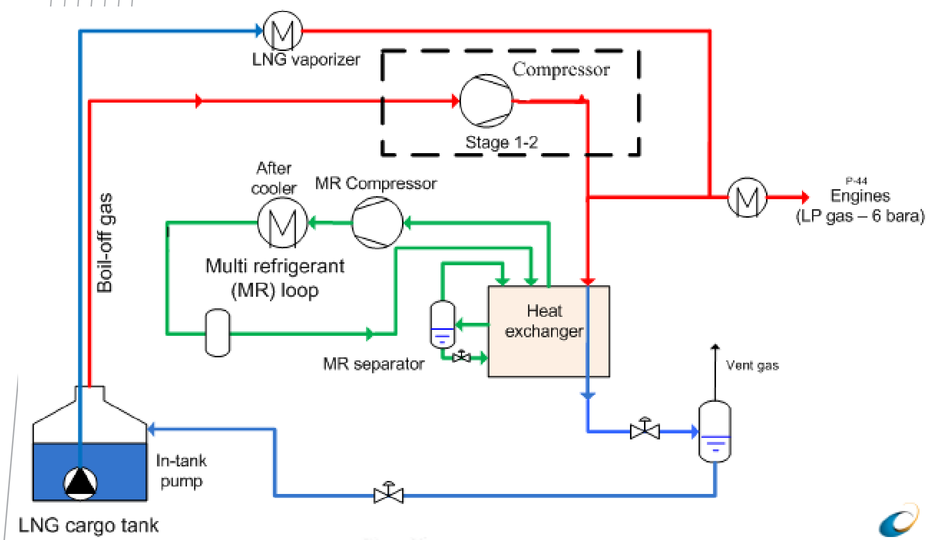


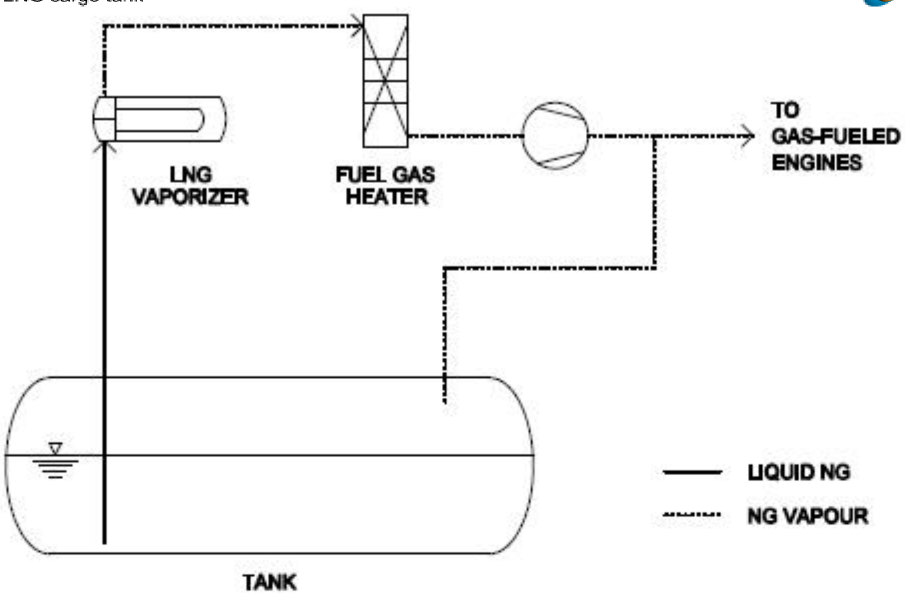
BOG liquefaction technology

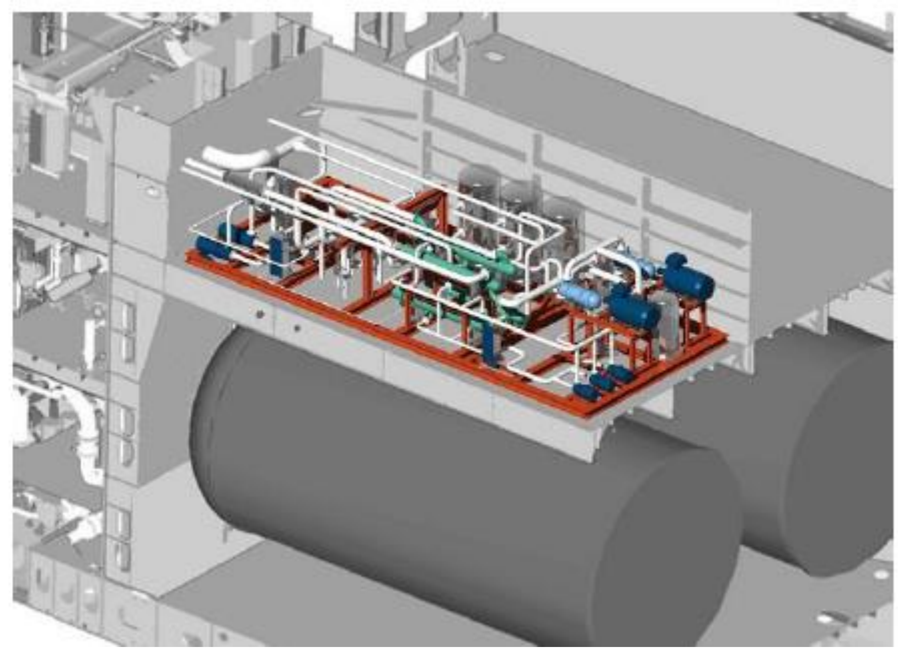


- Effective to treat continuous BOG
- To treat the BOG during LNG bunkering
  - Considerable capacity: 40 ton/hr to treat 40 ton BOG for 1 hr
  - Intermittent operation: 1 hr operation + 9 hr stop

Cargo handling and fuel gas system



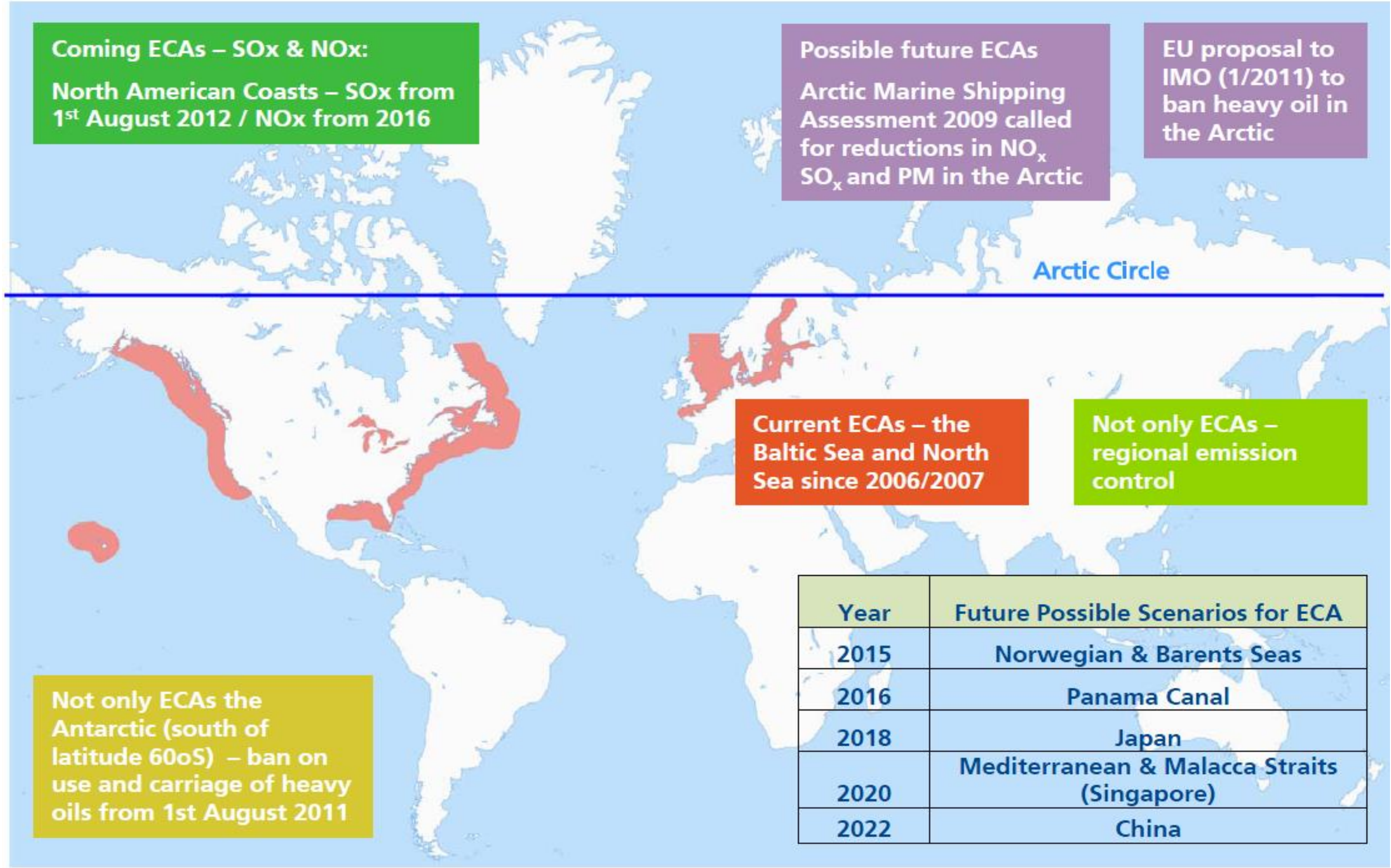




LNG-fuelled ship propulsion

Regulation on fuel quality within emission control area (ECA)

- Currently, the seas around Europe and the North America are ECAs.
- ECAs are expanding, ultimately all over the world.

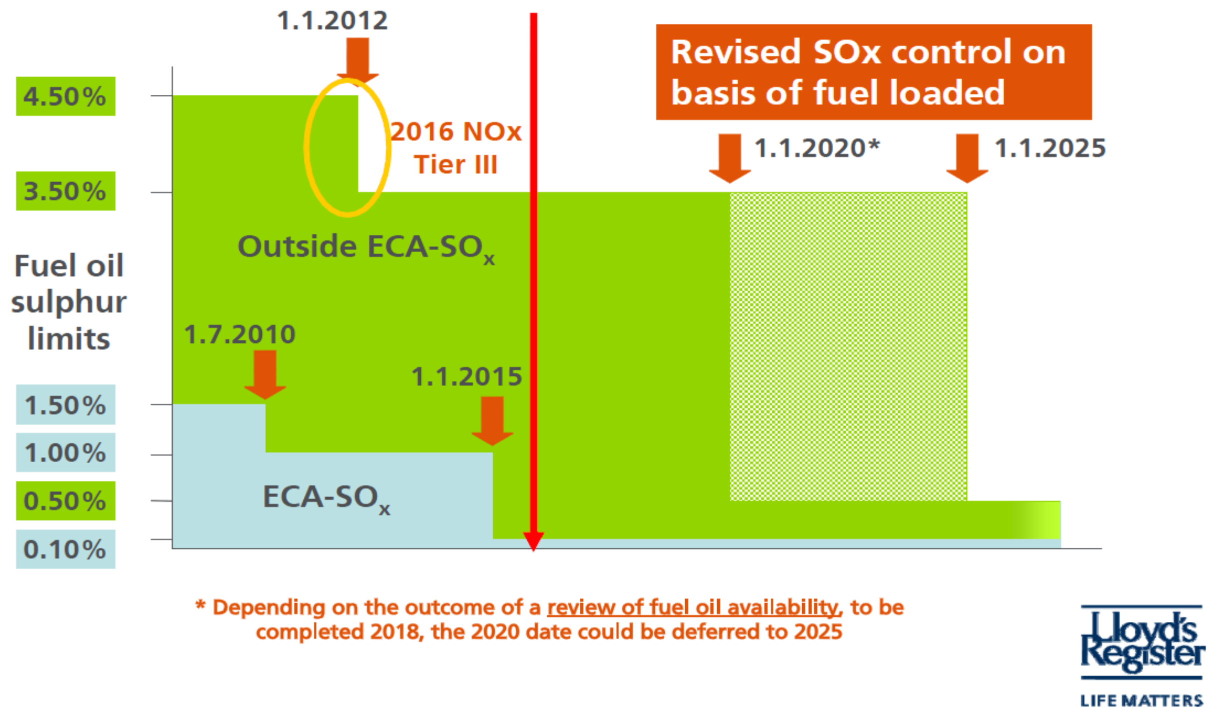


Year	Future Possible Scenarios for ECA
2015	Norwegian & Barents Seas
2016	Panama Canal
2018	Japan
2020	Mediterranean & Malacca Straits (Singapore)
2022	China

Regulation on fuel quality within emission control area (ECA)

- Regulations on emissions from ships, especially for SOx
  - Stringent regulation on fuel quality
  - Effective from 2015 for ECAs (emission control areas)

    from 2020 or 2025 globally



MARPOL Annex VI Requirements - SOx

LNG fuelled propulsion growing

- LNG fuelled propulsion: in service




Year	Ship Name	Ship Type	Ship Owner	Location	Tank	Engine	Fuel Type	Ships	Note
2000	Glutra	Car/pass. Ferry	Fjord1	Norway	**2 x 32 m3**	Mitsubish	**LNG**	1	In use
2003	Viking Energy	Offshore Supply	Eidesvik	Norway sea	**1 x 234 m3**	Wartsila	**LNG (DF)**	1	
2003	Stril Pioneer	Offshore Supply	Simon Mokster	Norway sea	**1 x 234 m3**	Wartsila	**LNG (DF)**	1	
2006	Bergens fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Fana fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Raune fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Stavanger fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2007	Mastra fjord	Car/pass. Ferry	Fjord1	Norway	**2 x 123 m3**	Rolls-Royce	**LNG**	1	
2008	Viking Queen	Offshore Supply	Eidesvik	Norway sea	**2 x 234 m3**	Wartsila	**LNG (DF)**	1	
2008	Viking Lady	Offshore Supply	Eidesvik	Norway sea	**2 x 234 m3**	Wartsila	**LNG (DF)**	1	
2009	Tidekongen	Pass. Ferry	Tide	France	**1 x 29 m3**	Mitsubish	**LNG**	2	
2009	Barentshav	Military Vessel	Norwegian Coast Guard	Norway	**1 x 234 m3**	Mitsubish	**LNG**	2	Under Building
2009	-	RO-RO	Sea Cargo AS	Norway	**2 x 216 m3**	Rolls-Royce	**LNG**	2	
2010	Molde fjord	Car/pass. Ferry	Fjord1	Poland	**1 x 125 m3**	Mitsubish	**LNG**	4	
-	-	Offshore Supply	-	Norway	**1 x 210 m3**	Mitsubish	**LNG**	1	

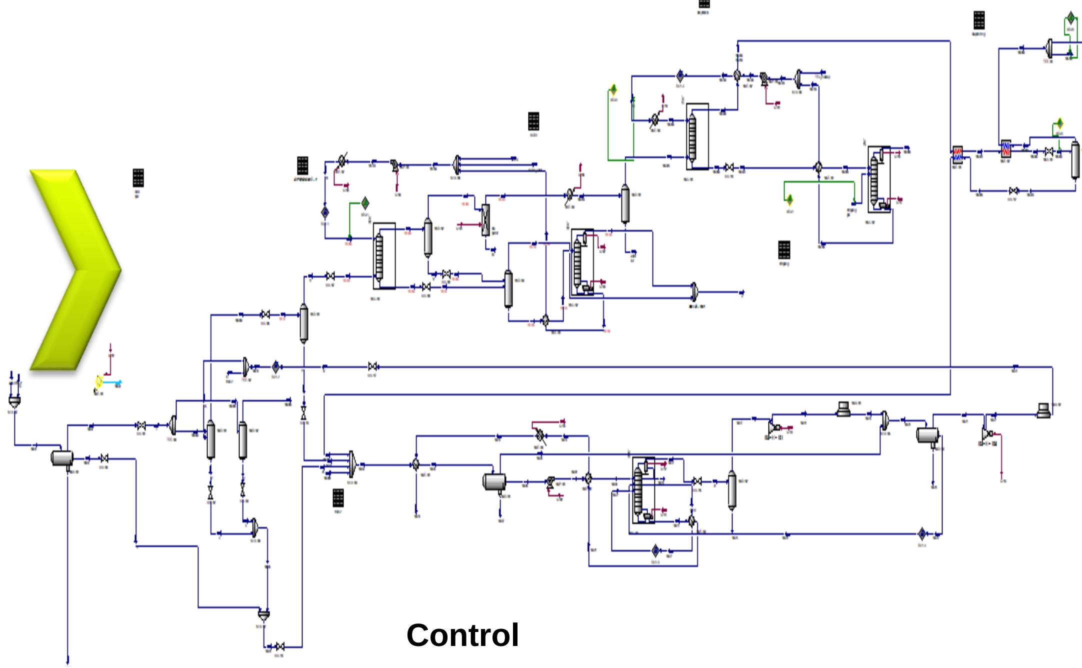
Case study: Gas processing design options

Case study: Gas processing process for ME

Gas processing to meet the products specification

Inlet fluids

- Natural gas
  N2, CO2, H2S
  C1, C2,
  C3, C4,
- Liquid Hydrocarbon
  C5+,
  Asphaltene.
- Condensed Water
- Formation Water
- Salts



- **Natural gas** → Natural gas For LNG or PNG
- **Condensate** → Stabilized condensate
- **Water** → Removed Water
  Removed salts

Input

FEED	Value
Hydrocarbon fluids	1020 MMscfd
: Gas rate	979 MMscfd
: Condensate rate	16100 bbl/d
Produced water	18,000 kg/hr
MEG injection for 80 wt%	5900 kg/hr

Control

Process unit	Pressure [barg]	Temperature [℃]
Separation	75 barg	25 ℃
Acid Gas Removal	72.5 barg	30~50 ℃
Dehydration	70 barg	25 ℃
NGL recovery	50 barg	RT
Condensate stabilizer	10 barg	50~200 ℃

Output

Products	Value
Natural gas	850 MMscfd
Condensate	16200 bbl/d
Regenerated MEG	5900 kg/hr

Gas Processing & Key Specifications for PNG

Feed gas

Refinery

PNG
to export pipeline

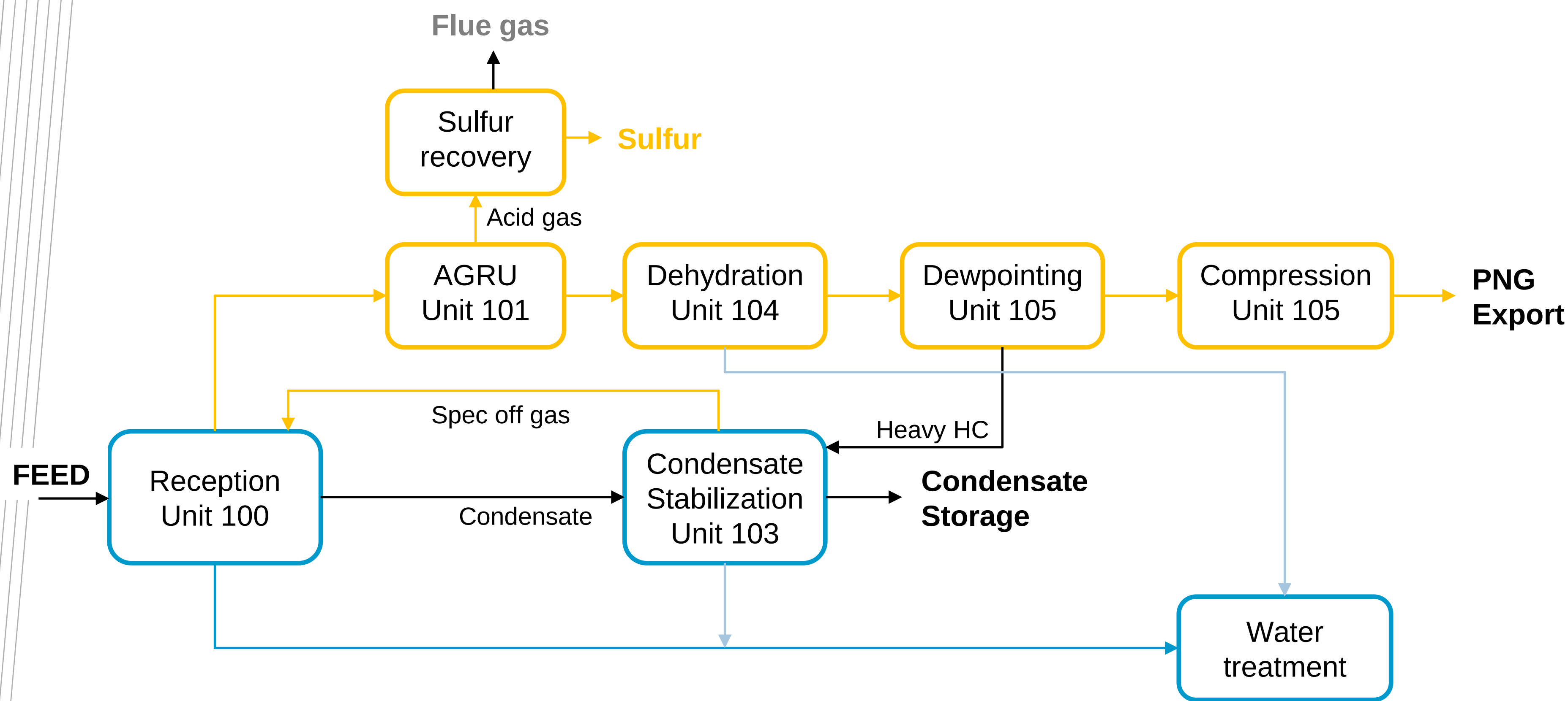
Condensate
(to storage tank)

Flue gas
(to atmosphere)

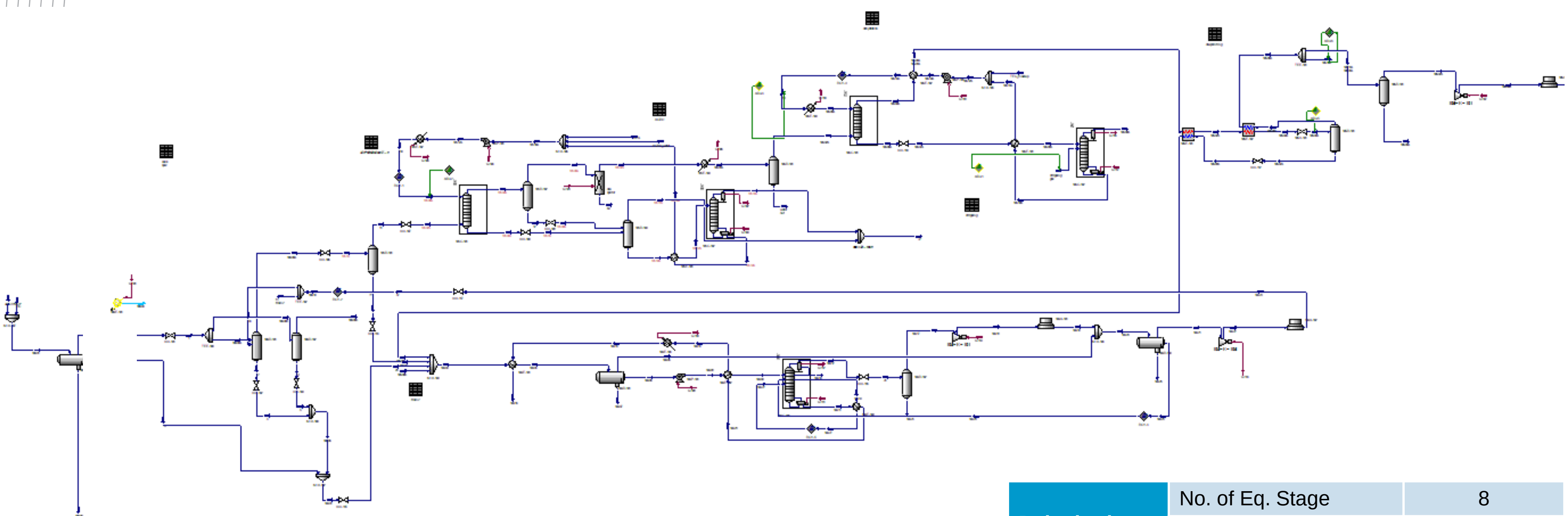
Composition	Mole fraction (%)
H_2O	2.58
N_2	2.61
CO_2	3.46
C1	86.26
C2	2.68
C3	0.68
iC4	0.19
nC4	0.21
iC5	0.13
nC5	0.10
C6	0.25
C7	0.20
C8	0.17
C9	0.08
C10	0.06
C11	0.04
C12+	0.15
C17+	0.09
C23+	0.05

		Specifications	Reference
Sales Gas (PNG)	Hydrogen Sulfide(H2S)	< 5 mg/Sm3	Specification of Natural Gas quality
	Mercaptan sulfur(R-SH)	< 15 mg/Sm3	
	Total Sulfur	< 30 mg/Sm3	
	Carbon Dioxide(CO2)	< 2 mol%	
	Total Inert gas (CO2+N2)	< 7 mol%	
	Water Dew point	< -10°C	
	Hydrocarbon Dew point	<-7°C	
	Higher Heating Value	35.59-43.96 MJ/Sm3	
	Wobbe Index	46.05-52.34 MJ/Sm3	
Gas Export Cond.	Export Pressure	92.8 barg	Design Basis
	Export Temperature	60°C	
Conde-nsates	RVP @ 37.8℃	<10 psia (summer) <12 psia (winter)	Specification of Condensate quality
	Free water content	< 500 ppm vol	
Enviro-nmental	Carbon monoxide	<150 ppm	Design Basis
	Hydrogen sulfide	< 10 mg/m3	
	Sulfur oxides	< 800 ppm	

Overall gas processing process



Simulation and Key Operating Conditions



*Aspen HYSYS v8.8
is used for the simulation

Slug catcher	Pressure	77.5 barg
	Temperature	40 °C
Separator	Pressure	75 barg
	Temperature	25 °C
AGRU -Absorber	No. of Eq. Stage	30
	Pressure	72.5 barg
	Temperature	27-56 °C
AGRU -Stripper	No. of Eq. Stage	24
	Pressure	1.4-1.6
	Temperature	93-131 °C

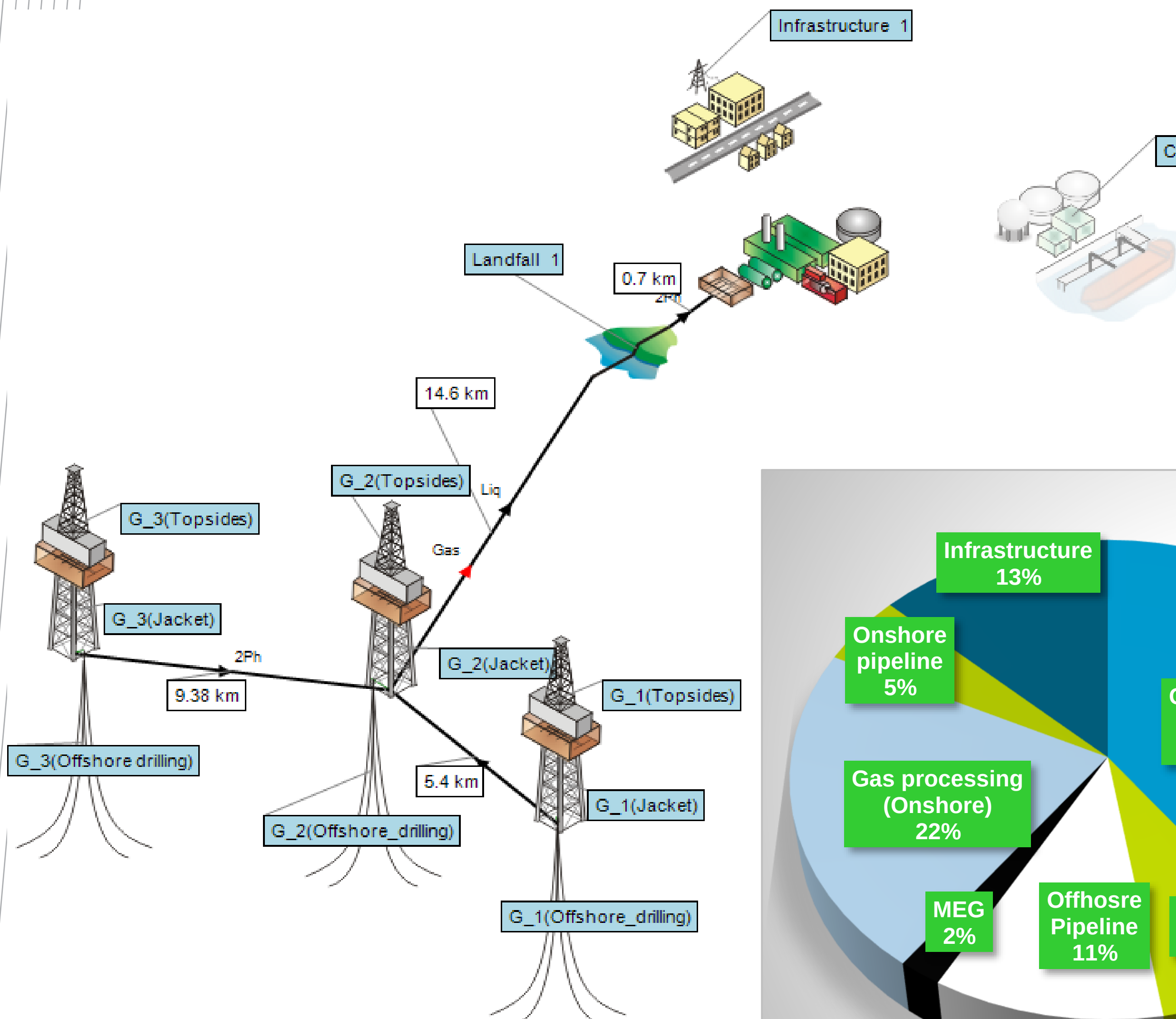
Dehydration -Absorber	No. of Eq. Stage	8
	Pressure	70 barg
	Temperature	25°C
Dehydration -Stripper	No. of Eq. Stage	5
	Pressure	0-0.1 barg
	Temperature	100-131°C
Dew pointing	Expansion Pres.	50 barg
Export comp.	Pressure	92.8 barg
	Temperature	60°C
Condensate stabilizer	No. of Eq. Stage	30
	Pressure	9.4-9.7 barg
	Temperature	62-200°C

Simulation Results

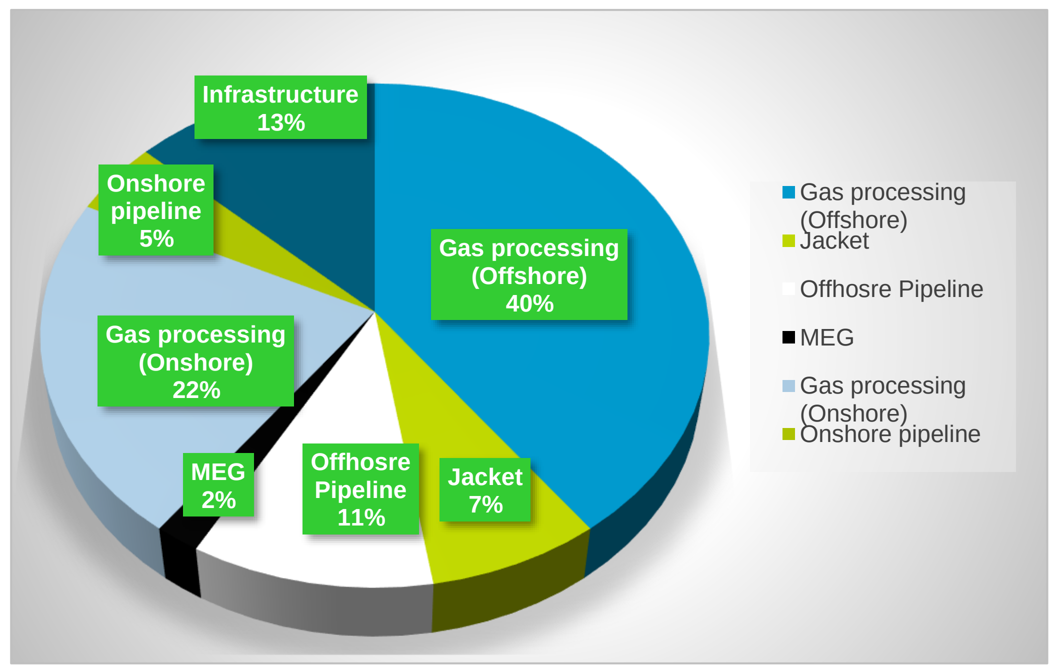
Specifications Check

	Required Spec.	Simulation Result	Spec Check
Hydrogen Sulfide(H2S)	< 5 mg/Sm3	4.92-4.99	Satisfied
Total Sulfur	< 30 mg/Sm3	12.3-12.5	Satisfied
Carbon Dioxide(CO2)	< 2 mol%	0.49-0.50	Satisfied
Total Inert gas (CO2+N2)	< 7 mol%	3.3%	Satisfied
Water Dew point	< -10°C	-10.1	Satisfied
Hydrocarbon Dew point	<-7°C	-19.7 to -22.8	Satisfied
Higher Heating Value	35.59-43.96 MJ/Sm3	38.25	Satisfied
Wobbe Index	46.05-52.34 MJ/Sm3	39.35	Satisfied
Export Pressure	92.8 barg	92.8	Satisfied
Export Temperature	60°C	60	Satisfied
Condensate RVP @ 37.8℃	<10/12 psia	8.4-8.6 psia	Satisfied
H2S in flue gas	10 mg/m3	trivial	Satisfied
Sulfur oxide in flue gas	<800 ppm	727 ppm	Satisfied

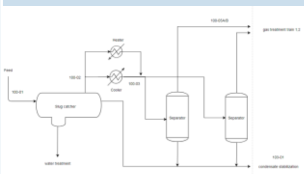
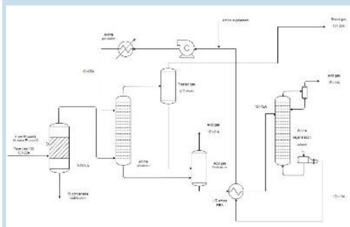
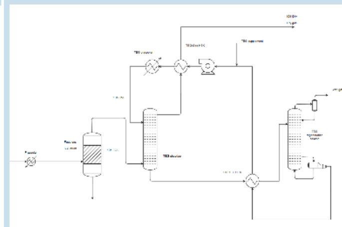
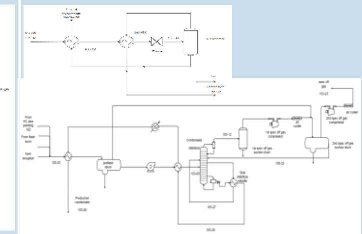
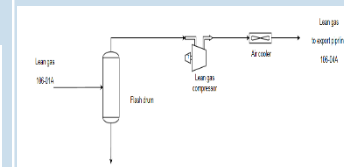
Gas field developments economics



CAPEX	USD
Gas processing (Offshore)	426,320,000
Jacket	81,752,000
Offshore Pipeline	114,980,000
MEG	21,419,000
Gas processing (Onshore)	235,741,000
Onshore pipeline	50,506,000
Infrastructure	140,076,000
Total	1,070,794,000



Gas processing cost breakdown

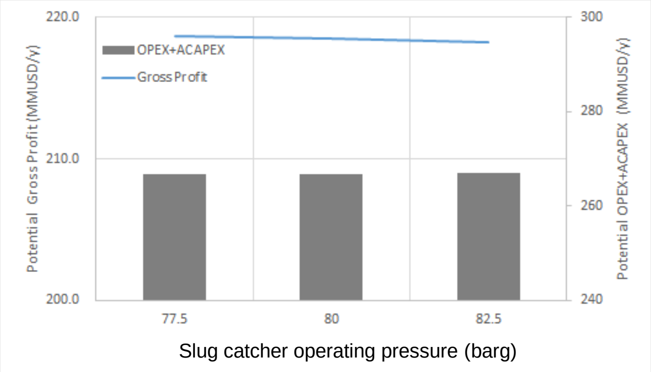
	Separation	Acid gas removal	Dehydration	Dewpoint control & Stabilization	Gas compression
PFD					
Units	  Slug catcher: 77.5 bar Separator: 75 bar Flow: 310000 kg/hr	 Pressure: 72.5 bar Amine regen. 131ºC Flow: 440000 kg/hr	 Pressure: 69.5 bar TEG regen. 131 ºC Flow: 400000 kg/hr	 Pressure: 50 bar Stabilization. 200 ºC Flow: 400000 kg/hr	  Pressure: 50 → 100 bar Temp. 50 → 93 ºC Flow 360000 kg/hr
CAPEX (USD)	513,000	259,000	1,148,000	2,216,000	60,344,000

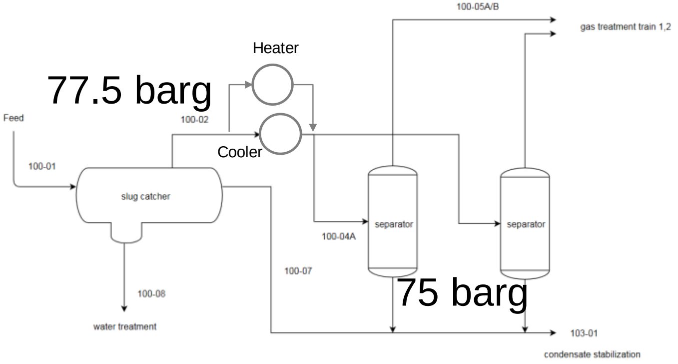
Operating Conditions – Separation Pressure

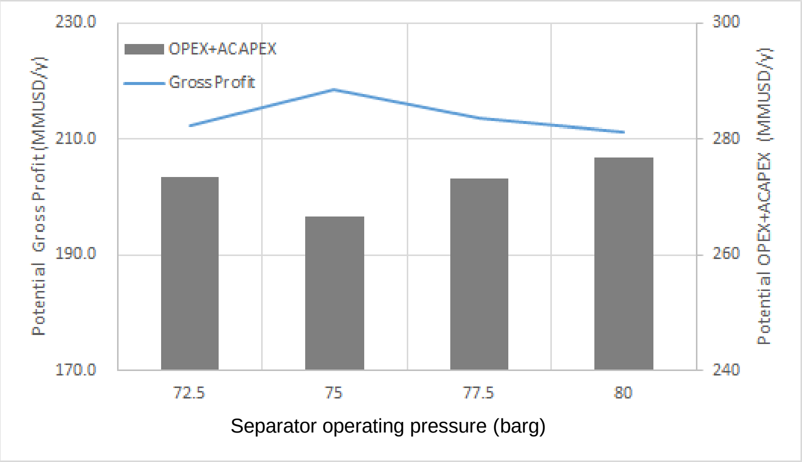
- To decide operating conditions, sensitivity analysis was performed, based on potential gross profit.
  - Potential gross profit is estimated as follows:

    Potential gross profit = Revenue – OPEX** – Annualized CAPEX****

    **Revenue was estimated by using gas (2.67USD/MMBtu)[1] and condensate (67.47 USD/bbl) price[2].*
- 77.5 and 75 barg is recommended as the operating pressure of slug catcher and separation
  - Higher P in separator makes higher CAPEX and results in decreased potential gross profit, although it has higher potential revenue due to more recovered condensates.
  - However, when the separation pressure is lower than 75, the increased heavy HC contents in gas stream requires lower operating P in dewpointing to satisfy the HC dew point specs. It causes increased CAPEX/OPEX for export compression, which decreases the potential gross profit.







** Minimum pressure drop between SL/separator was assumed as 2.5 bar.*

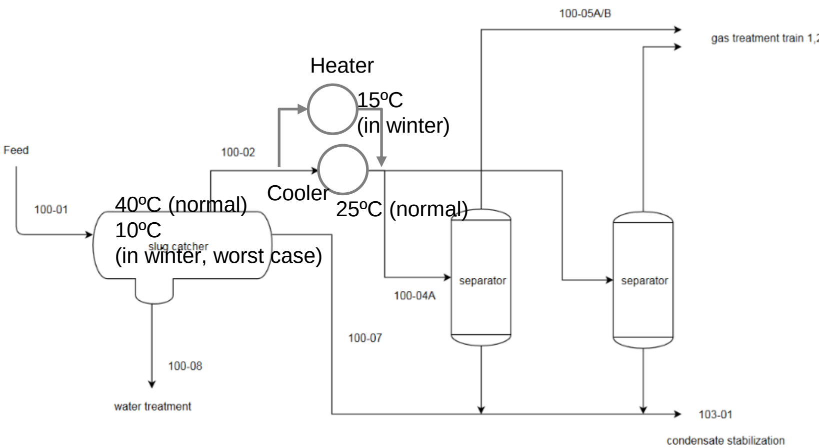
1) Gas price reference: Index mundi, Nature gas monthly price, Iran Feb, 2018. https://www.indexmundi.com/commodities/?commodity=natural-gas

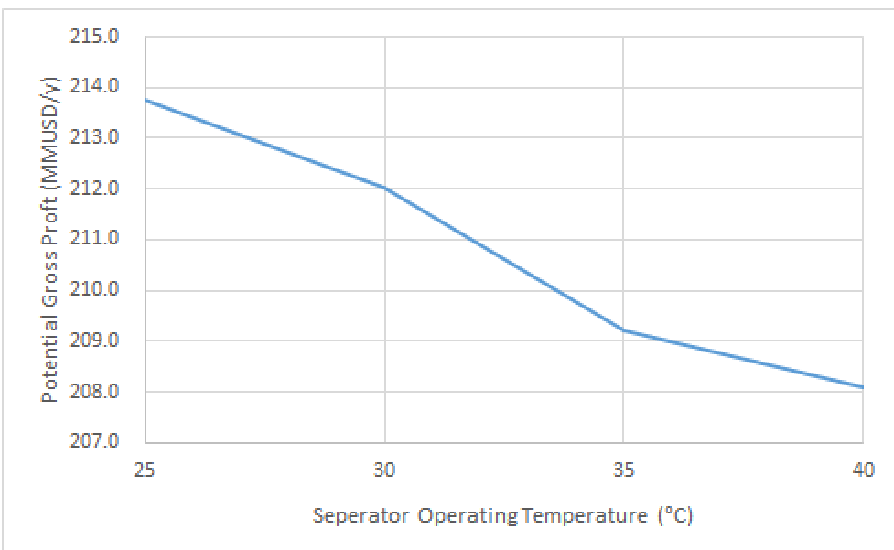
2) Condensate price reference: Iran Light, Deliveries to Northwest Europe. https://oilprice.com/oil-price-charts#prices

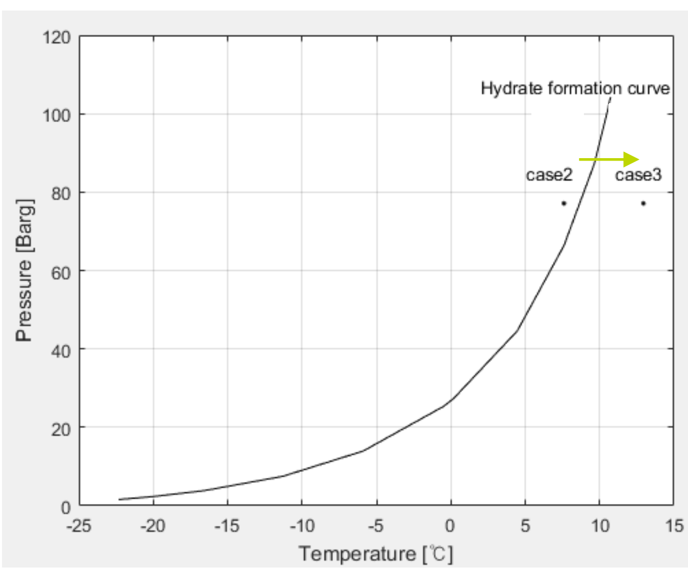
Operating Conditions – Separation Temperature

- Low operating temperature in Separator is recommended.
  - Lower temperature help to recover more condensate, increasing potential gross profit.
  - When the inlet temperature is too high, cooling before separation may help increase gross profit. CAPEX increase is relatively small.
  - However, too low temperature may cause hydrate formation problem. In winter season, therefore, heating may be required to prevent hydrate formation.

    : At least 15ºC is recommended considering safety margin.

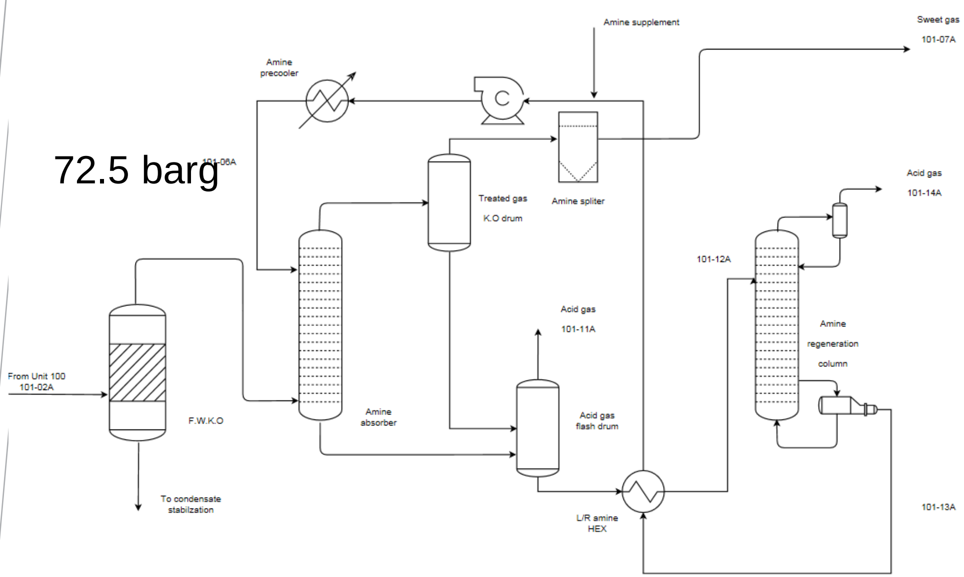


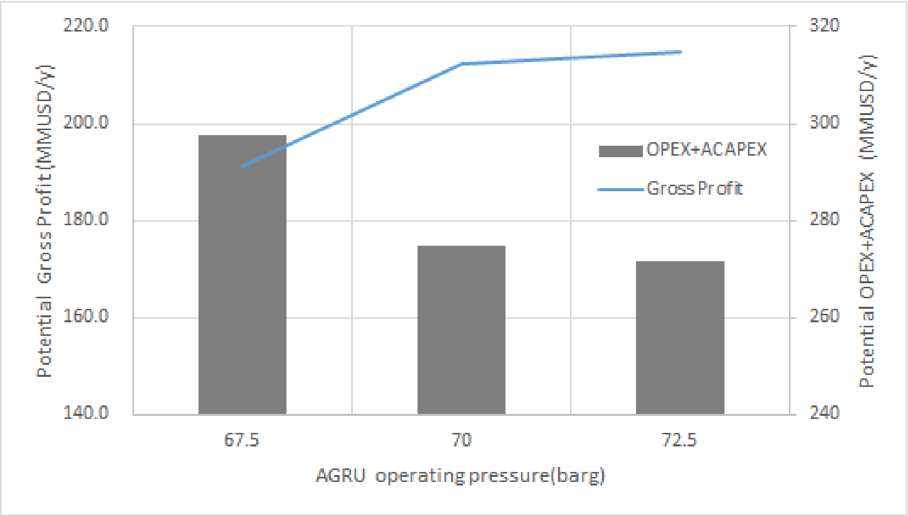




Operating Conditions – AGRU Pressure

- DEA amine absorption process is used.
  - DEA is well-known and one of most commonly used amine for AGRU in gas industries. Although it has slightly higher energy consumption than MDEA, it is still preferable option as a reference process conservatively, due to its long trustable history and wide track records.
- 72.5 barg is recommended for AGRU operating pressure*.
  - When the AGRU operating pressure becomes lower, the operating pressure in dewpointing also becomes lower to satisfy the HC dewpoint spec. It causes increased CAPEX and OPEX in export compression, decreasing gross profit.

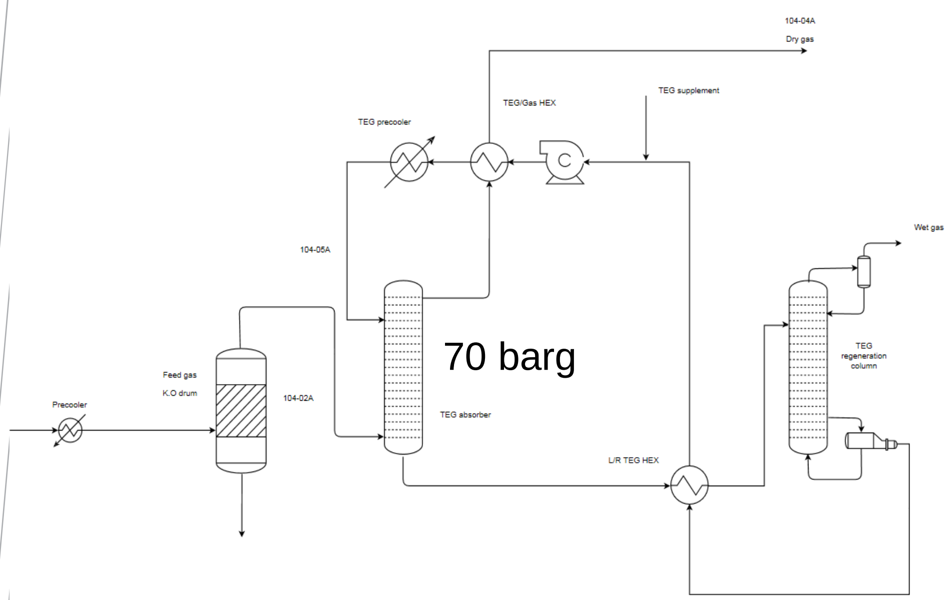


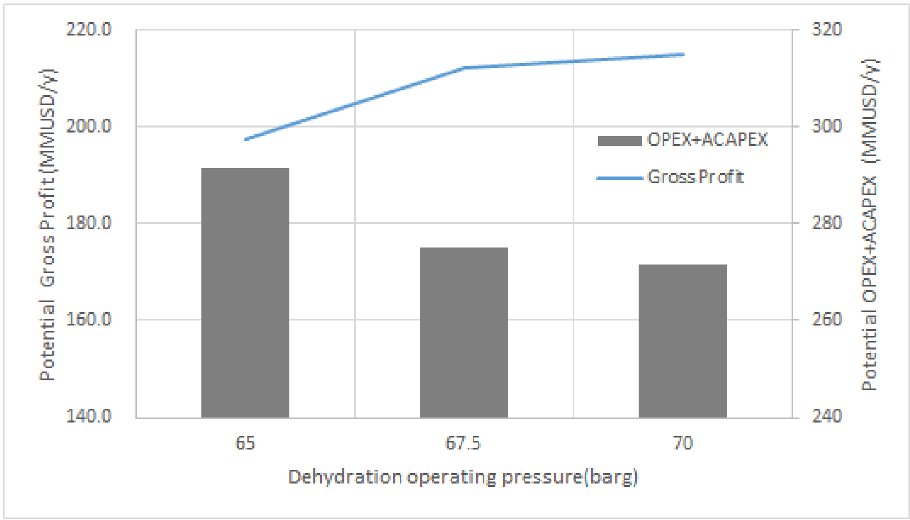


** Minimum pressure drop between modules was assumed as 2.5 bar.*

Operating Conditions –Dehydration Pressure

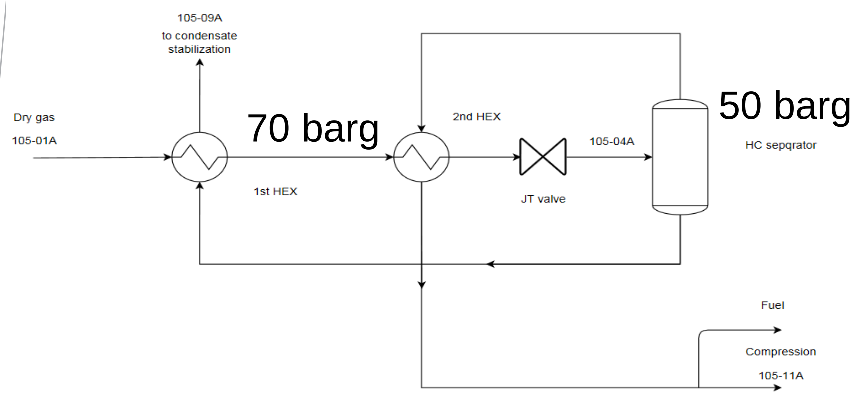
- TEG dehydration process is used.
  - TEG dehydration is a widely used dehydration process for PNG because it has a appreciably lower cost of installation and operation than adsorption (molecular sieve), although generally it will not reduce the water content as low as the adsorption*.
- 70 barg is recommended for dehydration operating pressure**.
  - When the dehydration operating pressure becomes lower, the operating pressure in dewpointing also becomes lower to satisfy the HC dewpoint spec. It causes increased CAPEX and OPEX in export compression, decreasing gross profit.

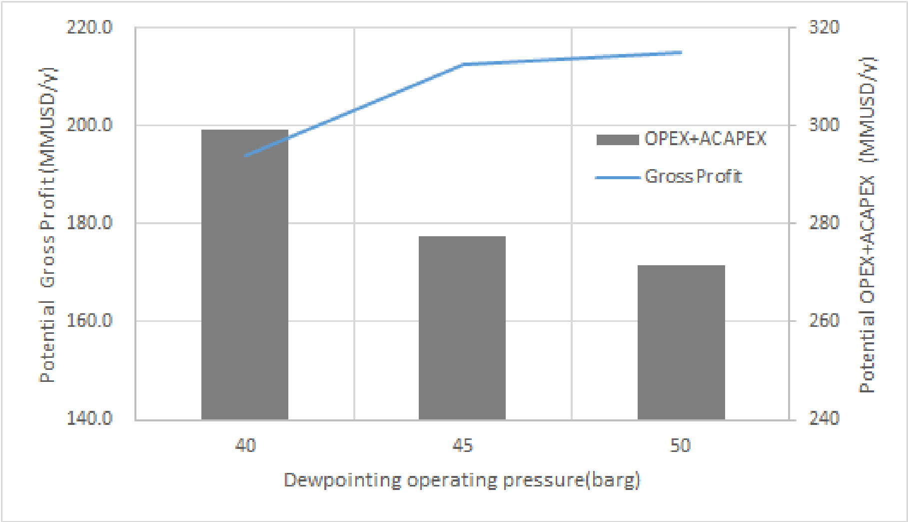




Operating Conditions – Dewpointing

- JT expansion process is used.
  - JT expansion uses the Joule-Thompson effect (temperature drop through a orifice). It does not require additional refrigerant, so is cheap and effective.
- Expansion to 50 barg is recommended for dewpointing operating pressure.
  - When dewpointing pressure decreases, CAPEX and OPEX in export compression increases, resulting reduced potential gross profit.
  - To satisfy the dewpoint specification, at least 20 bar of pressure drop is required. If the dewpointing pressure is higher than 50 barg, the produced gas cannot satisfy the dewpoint spec.





Joule-Thomson cooling for LNG production

- The Joule-Thomson (JT) coefficient is the change in temperature that results when a gas is expanded adiabatically from one constant pressure to another without doing external work.
- Thermodynamic definition:

$$\mu = \left(\frac{\partial T}{\partial P}\right)_h = -\frac{1}{C_p}\left(\frac{\partial H}{\partial P}\right)_T$$

- For a real gas, the JT coefficient may be positive (the gas cools upon expansion), negative (the gas warms upon expansion), or zero.
- Upon expansion from 101 bar to 1 bar, the cooling effect upon expansion when started at ambient temperature (27oC) is relatively small. But the cooling effect increases significantly as the initial temperature is lowered.

Temp (K)	Pressure (kPa)	JT coefficient (K/MPa)
250	500	6.161
250	1000	6.139
250	3000	6.013
250	5000	5.71
250	7500	5.047
250	10000	4.048
250	15000	2.043
250	17500	1.47
250	20000	1.062
250	25000	0.545
250	30000	0.244

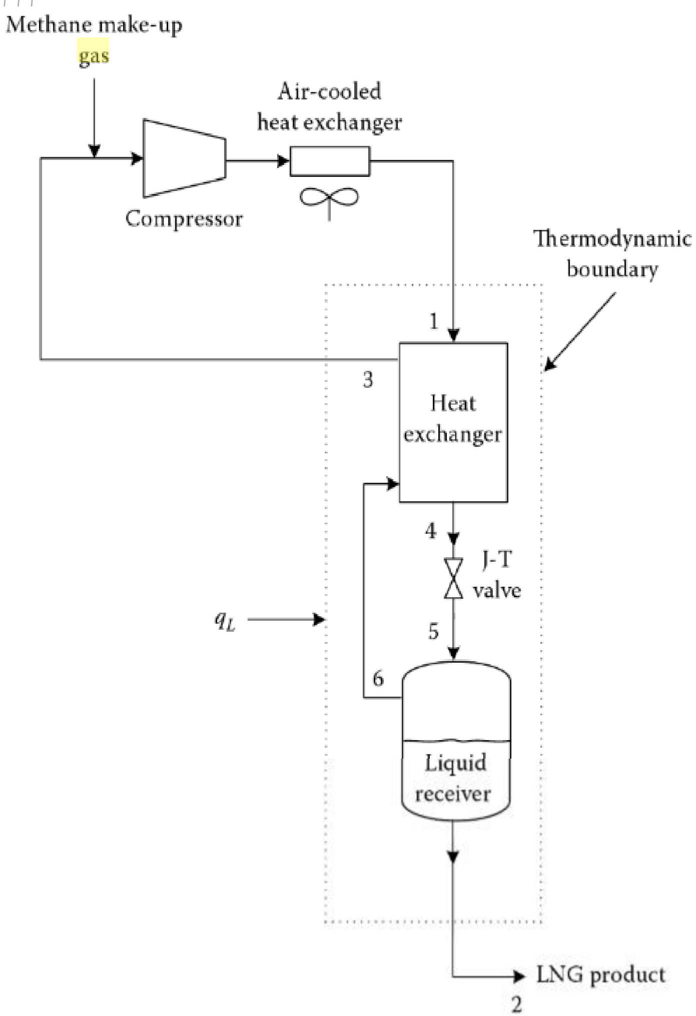
For methane gas,

Initial Temp (^oC)	Final Temp (^oC)	ΔT
27	-20	-47
-23	-87	-64
-43	-137	-94

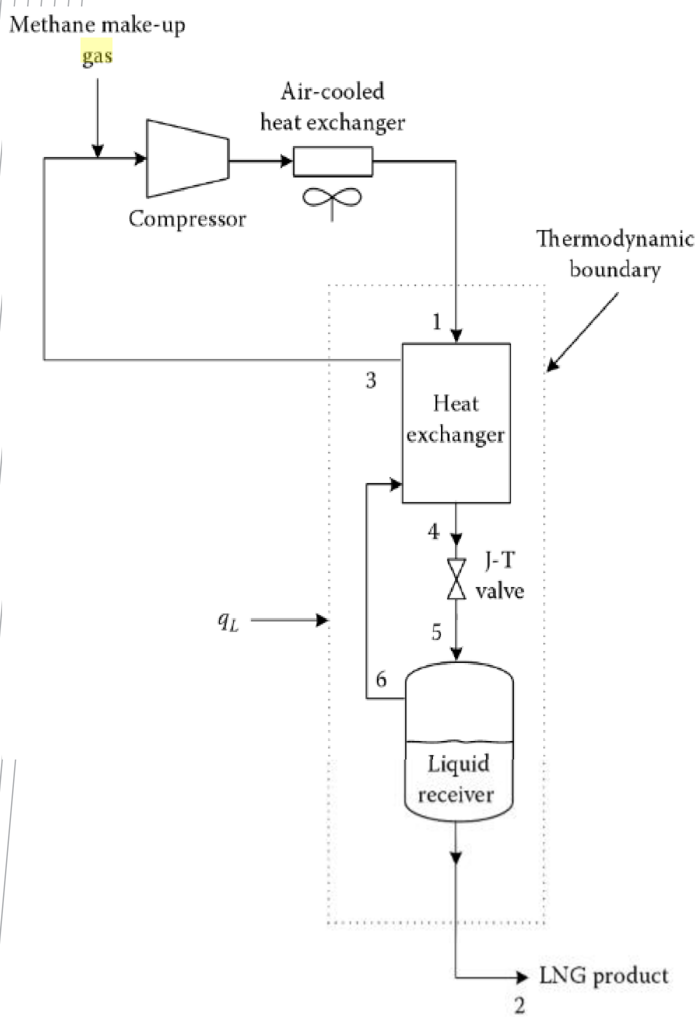
For nitrogen gas,

Initial Temp (^oC)	Final Temp (^oC)	ΔT
27	8	-19
-23	-51	-28
-43	-77	-34

Example: Simple JT liquefaction cycle



1) Methane is compressed and sent through the heat exchanger and expansion valve.
2) Upon expansion, the gas cools 47oC if the expansion is from 101 to 1 bar, but none liquefies because a temperature is not reached – 161 oC.
3) All of the chilled low-pressure gas is recycled through the heat exchanger for recompression.
4) This low pressure cold gas lowers the temperature of high pressure gas stream ahead of the expansion valve.
5) Temperature will be progressively lower upon expansion. The process continues until liquid is formed during the expansion from high to low pressure.
6) The liquid formed is separated from the low pressure gas stream in the liquid receiver. The amount of low pressure gas recycled to the compressor is now reduced, which cuts back on the cooling effect in the heat exchanger.
7) With the addition of makeup gas to the low pressure side of the compressor, a steady-state is reached in the liquefaction system.



- 1st law of thermodynamics for a steady-state flow system

$$0 = -\Delta[(h + KE + PE)m] + mq - mws$$

- For the thermodynamic boundary,

$$\Delta h = q_L$$

where the overall enthalpy change of the gas equals the heat leak per unit mass of the gas.

- On a per unit of mass flow of entering gas, $f = m_2 / m_1$, the fraction of entering gas withdrawn as a liquid, the equation becomes:

$$f h_2 + (1 - f) h_3 - h_1 = q_L$$

or

$$f = \frac{h_3 - h_1 - q_L}{h_3 - h_2}$$

- For a given system, h_2, h_3, and q_L are essentially fixed, so the only way to increase liquefaction is to decrease the inlet gas enthalpy, h_1, which is done by increasing the inlet pressure. Thus more compressor work lead to more liquid production.

- If methane enters the heat exchanger at 27oC and 101 bar, then expand to 1 bar, The fraction of methane that is liquefied can be calculated as follows,

  : Ideal heat exchanger – no pressure drop.

  : From the pressure-enthalpy diagram and saturation table,

  At 27 oC and 101 bar, h_1 = 350 Btu/lb

  At 27 oC and 1 bar, h_3 = 392 Btu/lb

  For liquid methane at – 161 oC and 1 bar, h_2 = 0 Btu/lb

  : Then the fraction is

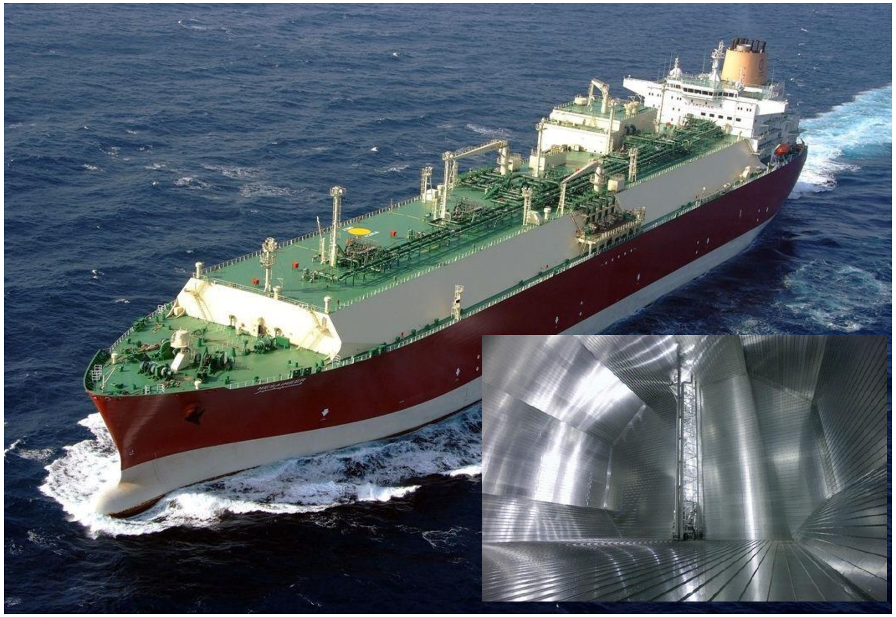
$$f = \frac{h_3 - h_1 - q_L}{h_3 - h_2} = \frac{392 - 350 - 0}{392 - 0} = 0.107$$

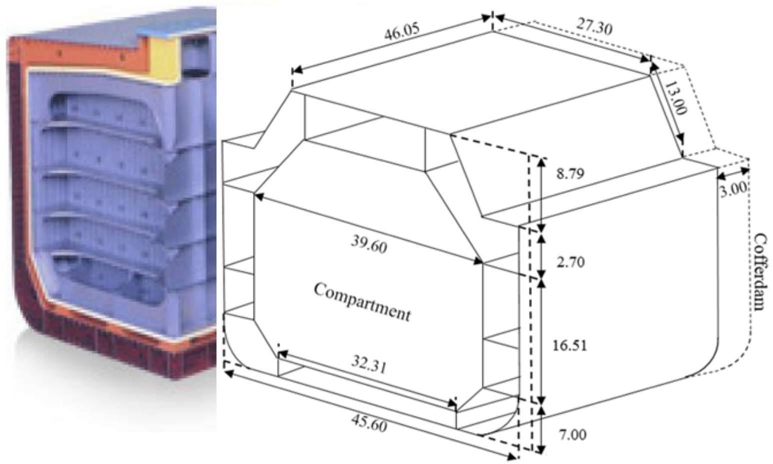
→ About 10% of the inlet methane stream is converted to liquefied methane.

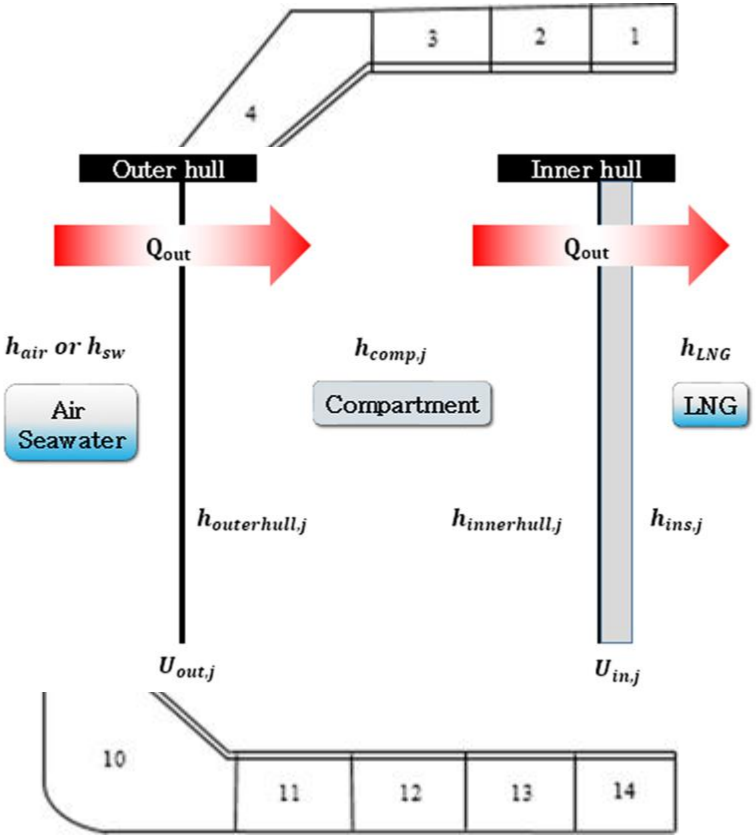
: The fraction become maximum when h_1 is minimum because the h_3 is fixed and q_L is independent of pressure. The mathematical criterion is $({}^{\partial h_1}/_{\partial P}) = 0$.

: From the definition, $\mu = (\frac{\partial T}{\partial P})_h = -\frac{1}{C_p}(\frac{\partial H}{\partial P})_T$, optimum pressure will occur when $\mu = 0$. However, many other factors must be considered in selecting the economically optimum inlet conditions.

Storage of LNG







Overall heat transfer coefficient, U

- The heat flow through Flat Panels is described using the overall heat transfer coefficient, U in W/m^2 ^{o}C

$$U = \frac{Q}{A\,(T_{env} - T_{LNG})}$$

Where Q is the overall heat flow received by the tank, A is the heat transfer area of the membrane in contact with LNG, T_{env} is the average temperature of the environment.

- Considering the heat convection and conduction around the panels,

$$U = \frac{1}{\frac{1}{h_{LNG}} + \frac{t}{\lambda} + \frac{1}{h_{env}}}$$

Where h_{LNG} and h_{env} are the convective heat transfer coefficient (W/m^2 ^{o}C) for LNG and environment, respectively, t is the thickness of the panel, and λ is the thermal conductivity of the panel (W/m ^{o}C)

- Once we determine the U value, thickness of the insulation layer can be calculated. For example, U value for LNG carrier was estimated 0.07 W/m^2 ^{o}C for 160 mm of R-PUF (Reinforced Polyurethane Foam) (λ=0.04 W/m ^{o}C).

Thank you!