HOW SUBSEA TECHNOLOGY IS ABLE TO PROVIDE A "SECOND" LIFE FOR THE DRAUGEN FIELD

Draugen, Subsea Boosting and Industry Initiatives

Richard Tong
Senior Subsea Processing Engineer

AGENDA

Courtesy of: Heine Schjølberg

1.0 Introduction to Draugen

2.0 Draugen Infill Project

3.0 Subsea Pumping System

- Scope of Supply - Testing - Technology Qualification API 17N

4.0 Technology & Industry Initiatives on Subsea Boosting

5.0 Field Screening of Subsea Boosting

1.0

DRAUGEN

History and Introduction to Draugen

HISTORY OF DRAUGEN

- First and only Single-leg GBS platform
- Low number of wells, due to successful production strategy
- Continuous project activity and investments underway to make Draugen a high integrity mature producer
- Robust and sustainable design; fit-for-purpose for potential future 3rd party Tie- ins







HISTORY OF DRAUGEN

Draugen Field Résumé

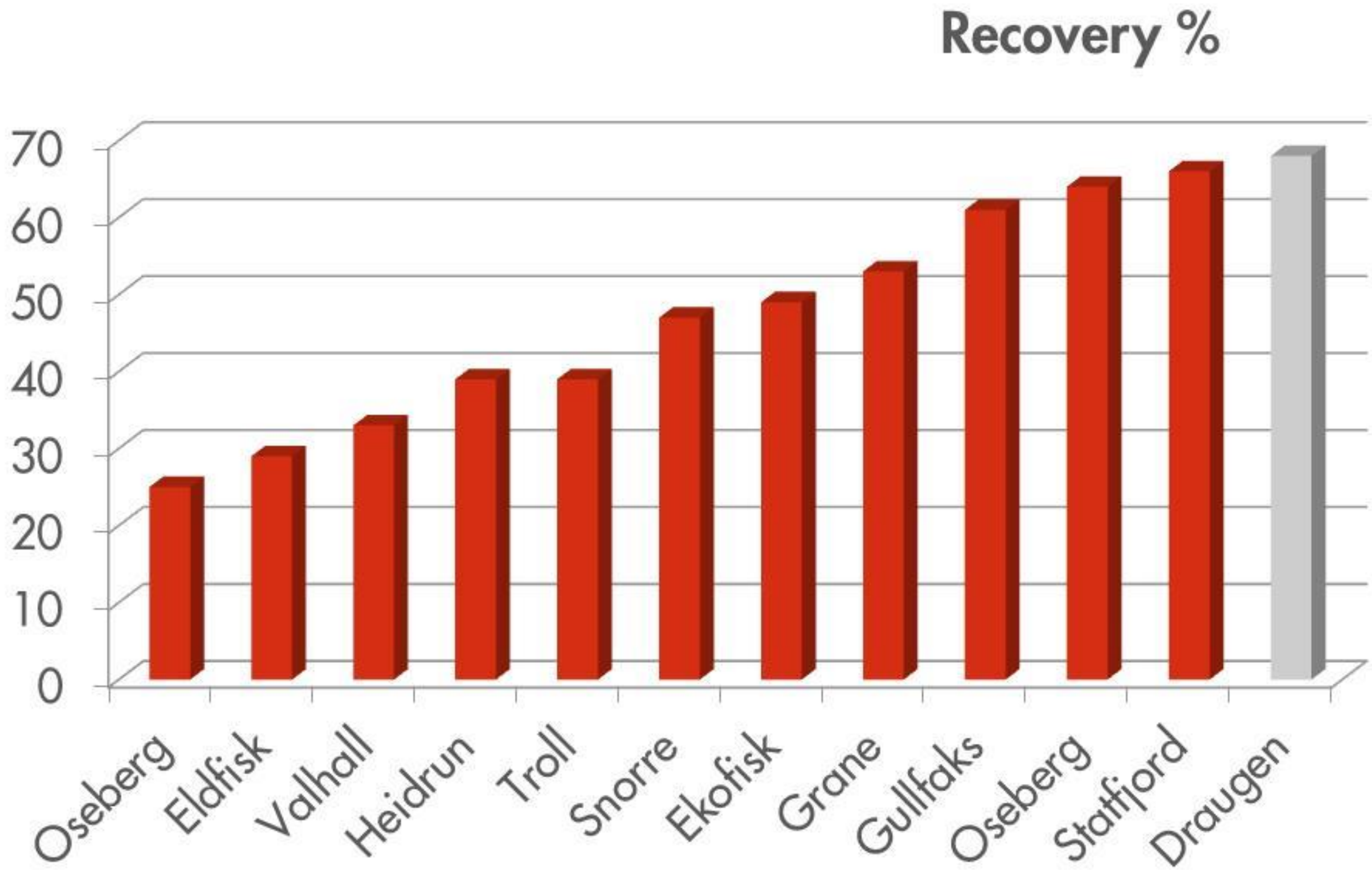
- Field Properties
  - Located in Haltenbanken area, 140km North of Kristiansund
  - Discovered in 1984 and production start 19.10.1993
  - Partners: A/S Norske Shell (Operator, 44.56%),
    Petoro AS (47.88%), VNG (7.56%)
  - Water Depth ~ 250-280 m
  - Peak Production 225 000 bbl/day
  - High uptime- high recovery

HISTORY OF DRAUGEN

Draugen Field Résumé (continued)

- Geological / Geophysical Properties
  - Main reservoir in sandstone: Rogn and Garn Formations of Late and Middle Jurassic ages respectively
  - "World-Class" Reservoir at 1600m depth
  - Produced by pressure maintenance from water injection and aquifer support; gas lift used

DRAUGEN

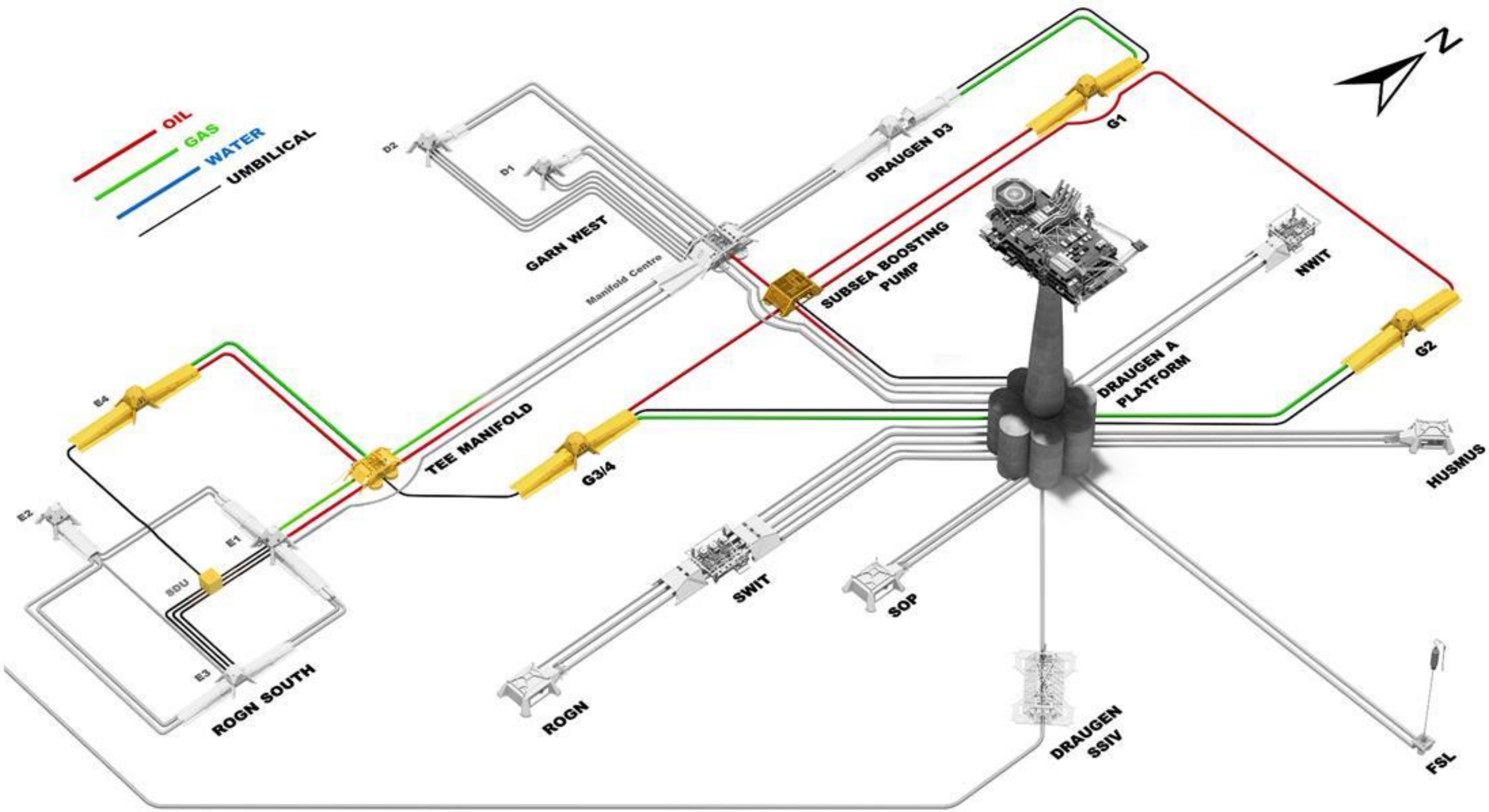

Recovery %
70
60
50
40
30
20
10
0
Oseberg
Eldfisk
Valhall
Heidrun
Troll
Snorre
Ekofisk
Grane
Gullfaks
Oseberg
Statfjord
Draugen

2.0

DRAUGEN INFILL PROJECT

Project Scope

DRAUGEN INFILL DRILLING CAMPAIGN

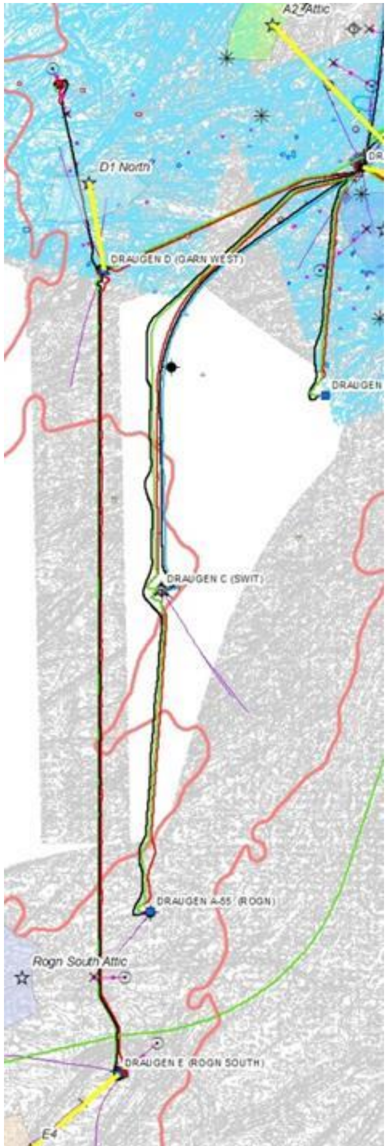


DRAUGEN INFILL DRILLING CAMPAIGN

Draugen Infill Drilling Campaign

- 4x New Subsea Production Wells
- Subsea Boosting Pump
- Subsea Tee Manifold @ Rogn South
- 19 km of New Flowlines
- 11 km of New Umbilicals
- 52 tie-ins
- 113 GRP Covers
- 70 Concrete Mattresses
- 245 000 m^3 Rock Installation
- 11 000 m^3 Rock Removal

HYDRATE PLUG RISK FOR SUBSEA FLOWLINES



Risk Description:

Cause - Lift gas circulated in flowlines
Potential Event - At an unexpected long shutdown, a hydrate plug may form
Consequence - Loss of flowline, i.e. potential loss of production

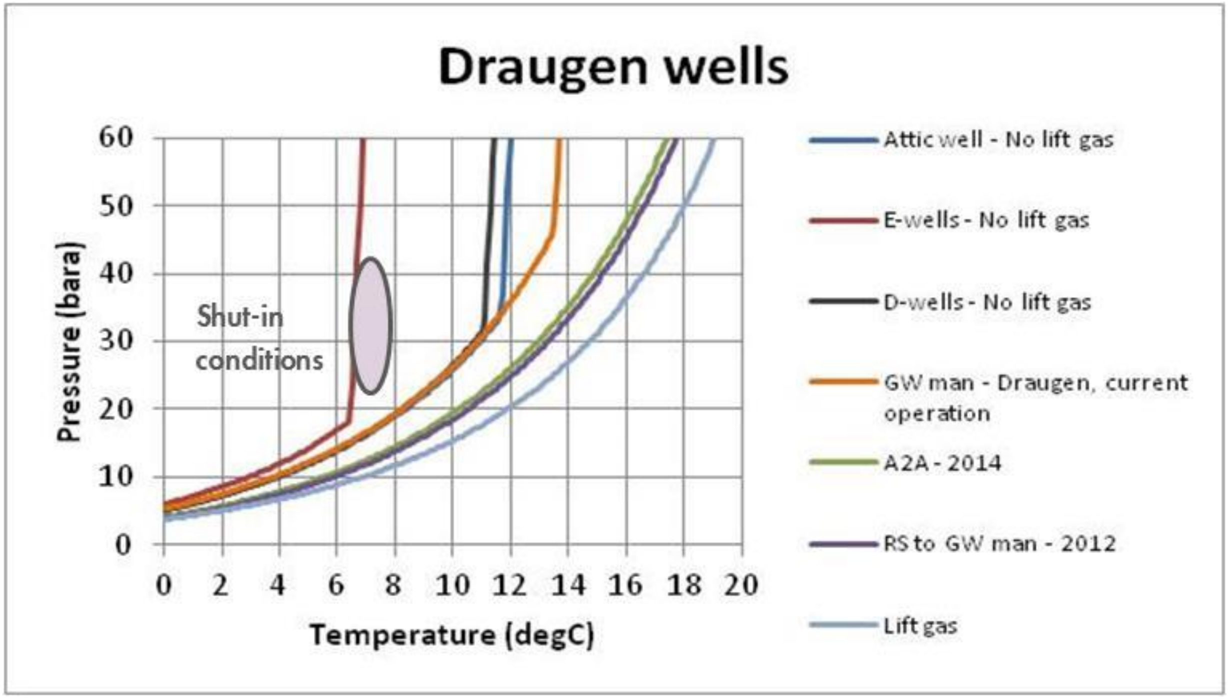
Risked Value = Cost x Probability

Assumptions-Information:

- The plug can only be remediated by flowline replacement
- Gas lift will have to be used in the future to maintain the production

HYDRATE FORMATION RISK

- Hydrate formation risk was a key factor towards driving concept towards subsea pump
- Experimental and theoretical work indicates hydrate formation is possible with Draugen oil. Risk increases with introduction of lift gas



DRAUGEN INFILL DRILLING CAMPAIGN

Advantages of Framo Dual-Pump Station (FDS)

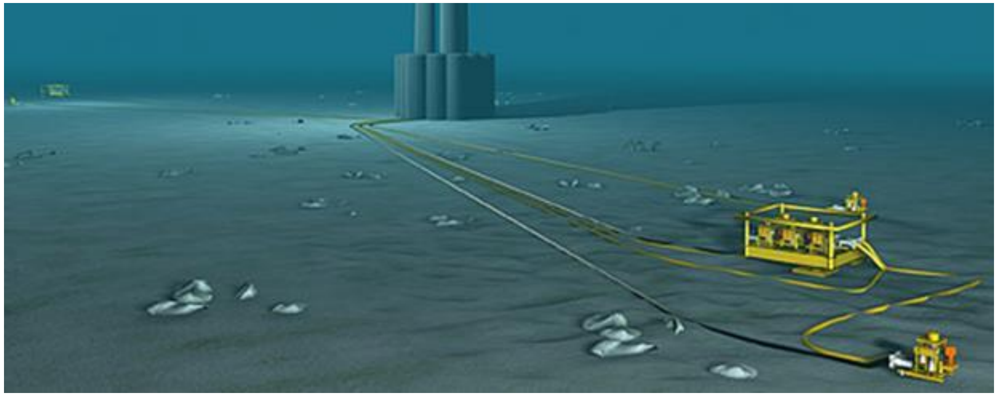
- Subsea Boosting Pump Station
  - Reduces back pressure "seen" by wells = increased oil recovery ~70%
  - Accelerated End-of-Field Life production
  - Increased efficiency as water cut increases over time
  - Reduces risk of hydrate formation – no need for continuous gas lift
  - Allow field start-up
  - Offers metering of new wells coming on-stream
  - Future expansion flexibility

3.0

DRAUGEN SUBSEA PUMPING SYSTEM

WORLD'S FIRST MULTIPHASE SUBSEA PUMP
A/S Norske Shell Draugen Field

Contract Award:	1990
Sales:	FMC Kongsberg, Norway
Pump Integration:	FMC Kongsberg, Norway
Pump Fabrication:	Framo, Norway
Host Type:	Draugen GBS Platform
Contract Type:	EPC
Water Depth:	280 m (920 ft)



The Draugen Subsea Well Facilities Contract was the largest subsea EPC contract in Norway at the time. All subsea installations were designed for diverless installation, operation and maintenance.

The seabed pumps (i.e. system integration of FRAMO pumps) were the world's first commercial multi-phase pump installation.

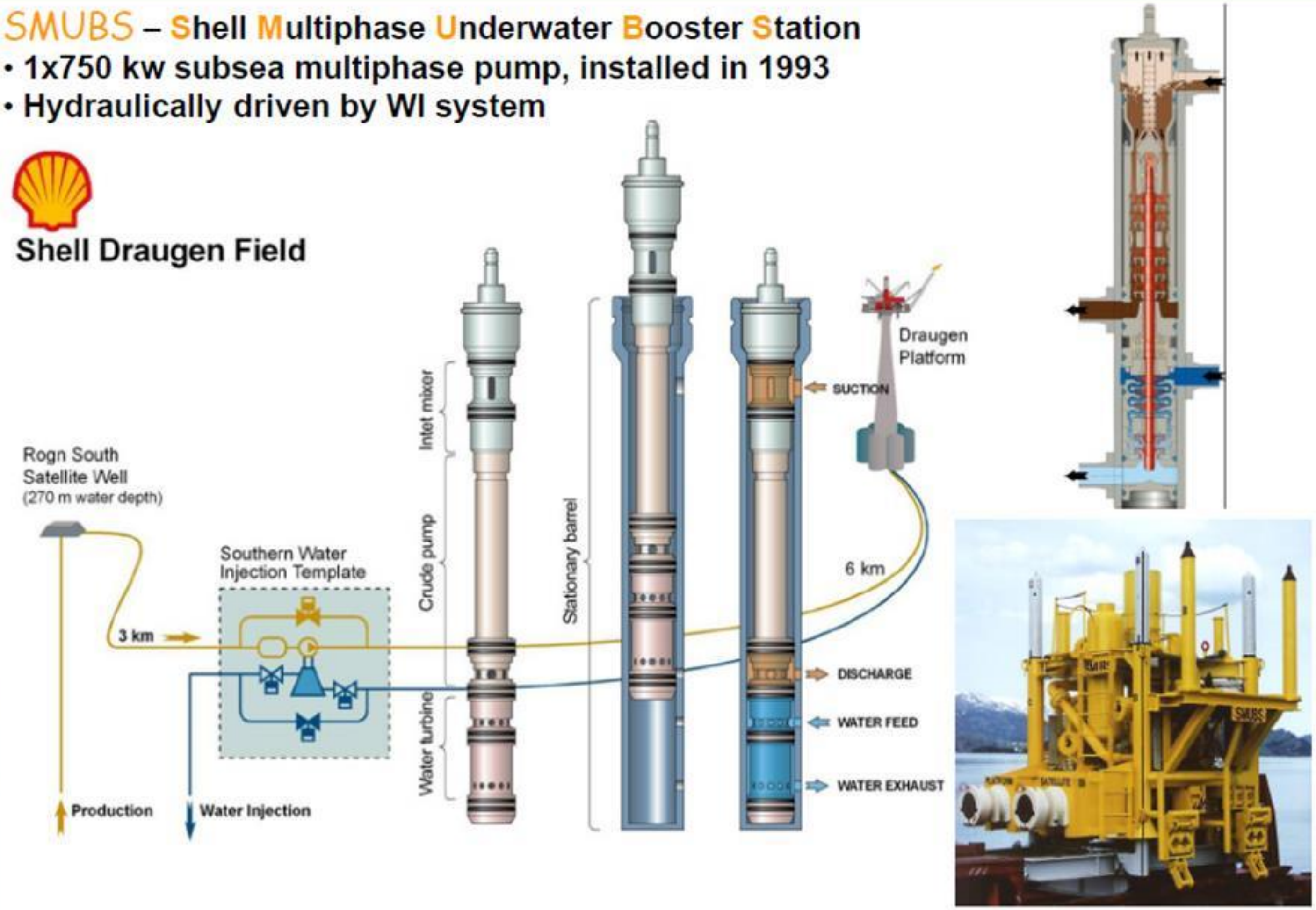
The pump was installed in 1993. It ran sucessfully from 1995 for 12.2 months (1000 operating hours) and was decomissioned and abandoned due to change in water injection strategy.

Oil and Gas Journal: *"Norske Shell has let a $100-million contract to Framo Engineering for a complete subsea multiphase booster pump system for Draugen oil field offshore Norway, where the world's first such system was installed in 1994."*

AS Norske Shell Draugen Field, North Sea

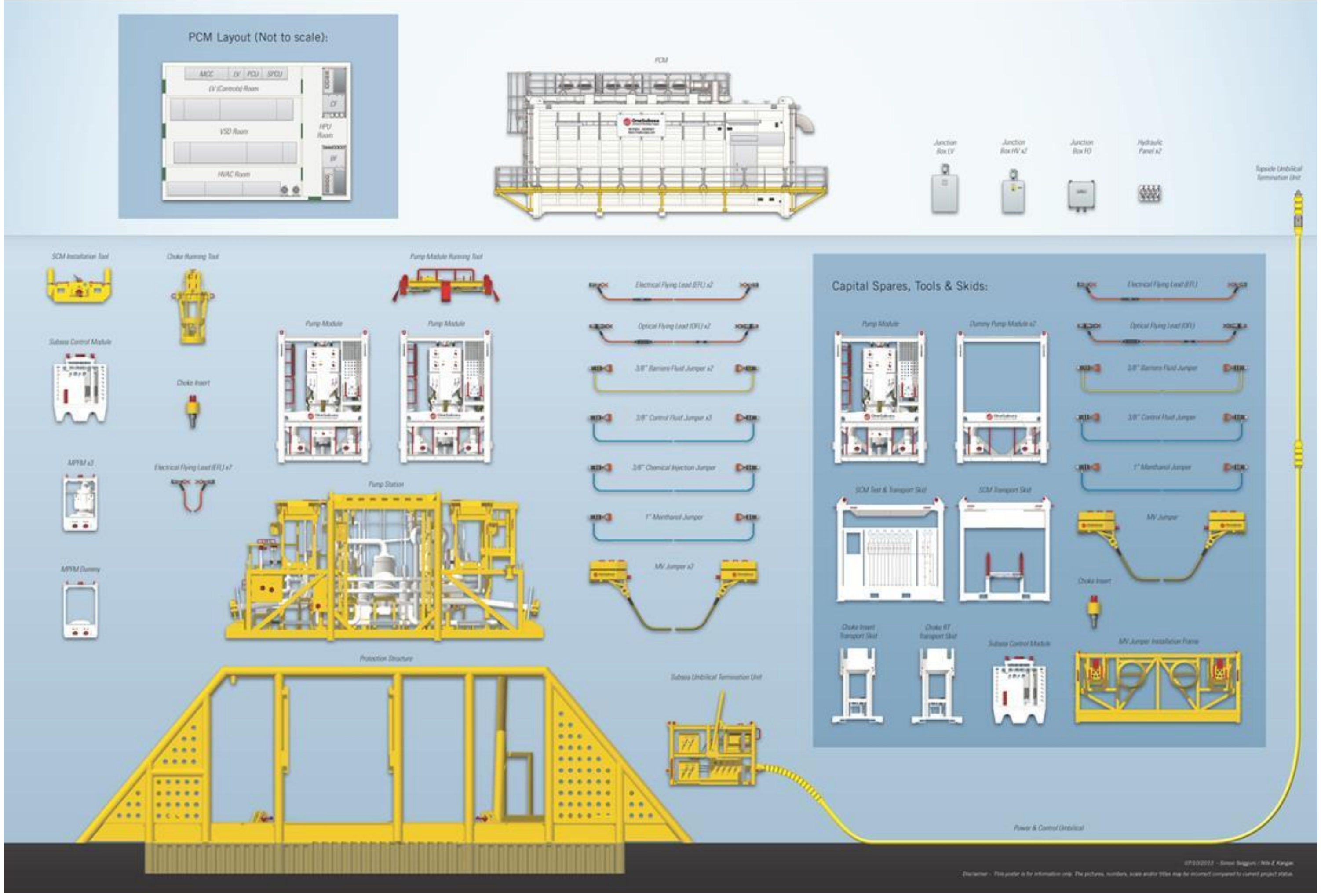
SMUBS – **S**hell **M**ultiphase **U**nderwater **B**ooster **S**tation

- 1x750 kw subsea multiphase pump, installed in 1993
- Hydraulically driven by WI system



SPE APPLIED TECHNOLOGY WORKSHOP – OSLO 8th February 2005

DRAUGEN SUBSEA PUMP SYSTEM
SCOPE OF SUPPLY

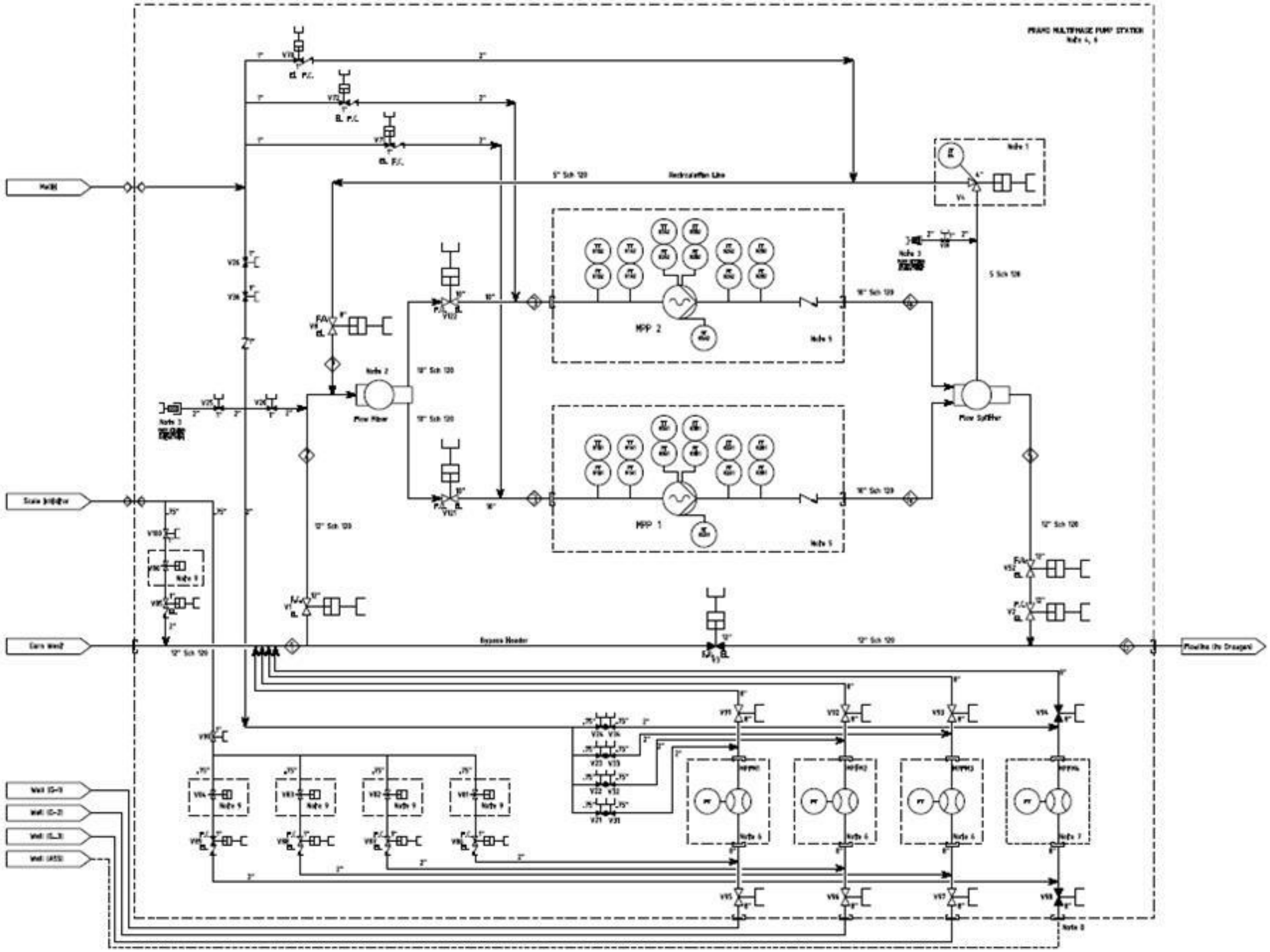


DRAUGEN INFILL PROJECT PUMPING SYSTEM

- Reduces back pressure “seen” by wells = increased oil recovery
- Accelerated end-of-field life production
- Avoid continuous gas lift, reduces hydrate formation risk
- Offers metering of new wells coming on stream & expansion flexibility

- Tie-back distance (To Draugen): ~4 km (12” flexible)
- Ambient Temperature (seawater): 6 – 8 °C
- Design temperature (flowlines): 75 °C
- Design pressure: 220 bar
- Number of Pumps: 2
- Motor Rating: 2300 kW
- Maximum dP: 50 bar

PFD



HELICO-AXIAL PUMPS

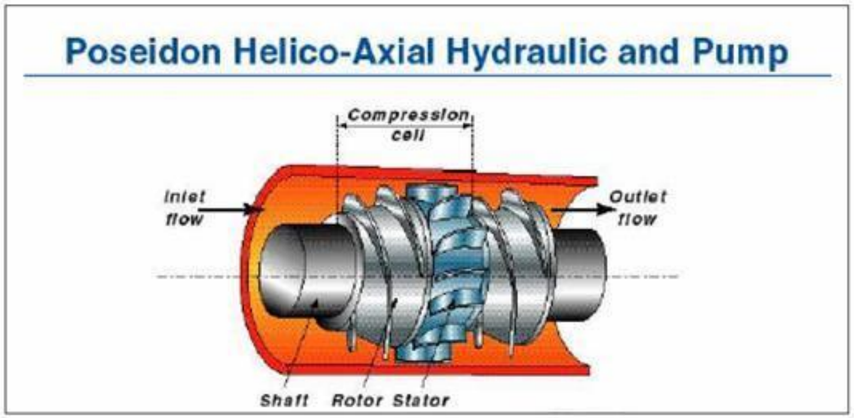
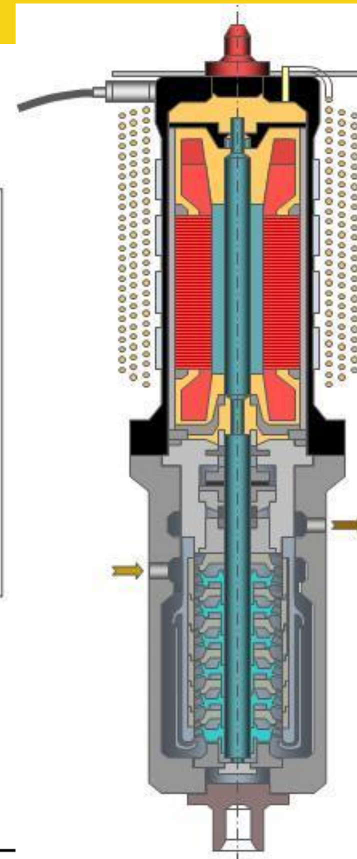


Figure 19: Helico-axial pump



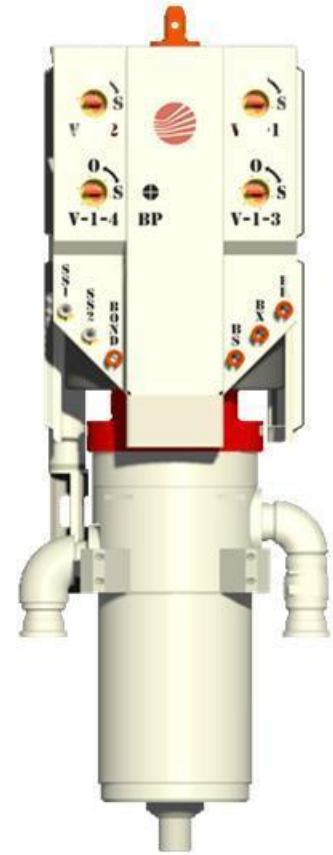


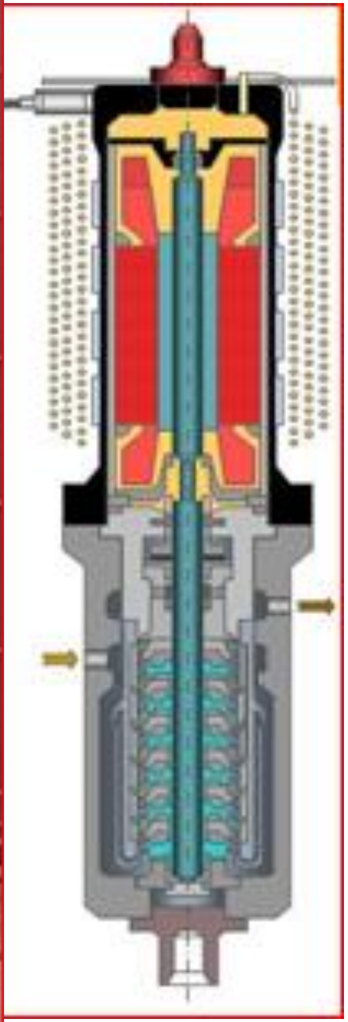
Table 7: Historical operating parameters of subsea helico-axial pumps

Helico Axial Pumps											
Project Field	Project Type	Area	Operator	Start (year)	Water Depth (feet)	Tie-back Distance (miles)	Total Flowrate (bpd)	Flowrate per Pump (bpd)	Diff Press (psi)	GVF (%)	Current Status @ February, 2010
Draugen Field	SMUBS, 1-MPP	Norway North Sea	Norske Shell	1995	886	4	29,200	29,200	773	42	Abandoned after 12 months
Topacio Field	2-MPPs	Equatorial Guinea	ExxonMobil	2000	1641	6	142,000	71,000	508	75	Operating after 114 months
Ceiba C3 C4	2-MPPs	Equatorial Guinea	Hess	2002	2461	5	90,600	45,300	653	75	Operating after 88 months
Ceiba Field FFD	5-MPPs	Equatorial Guinea	Hess	2003	2297	5	337,600	67,520	580	75	Operating after 74 months
Mutineer Exeter	2-MPPs	NWS Australia	Santos	2005	476	4	181,300	90,650	435	40	Operating after 59 months
Brenda & Nicole Fields	Multi Manif w/ 1-MPP	UK North Sea	OILEXCO N.S.	2007	476	5	120,800	120,800	276	75	Operating after 34 months

Draugen Pump System Parameters

➢ Design pressure:	220 barg
➢ Process operating temperature:	4 to 75 °C
➢ Max pump differential pressure:	50 bar
➢ Pump suction pressure:	21 - 29 bara
➢ Pump suction GVF:	10 - 32% (75%)
➢ Pump flow rate:	643 - 855 Am3/h
➢ Pump speed:	1500 – 4200 rpm
➢ Pump motor shaft power:	2300 kW
➢ Water Depth:	268 m

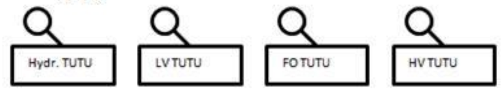
MULTIPHASE PUMP

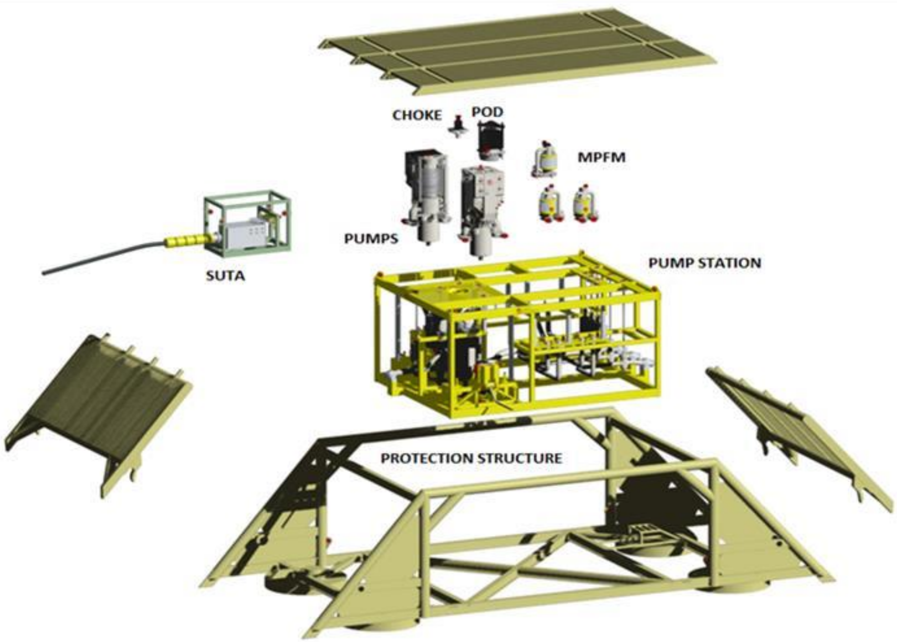


PUMPING SYSTEM SCOPE OF SUPPLY

PCM

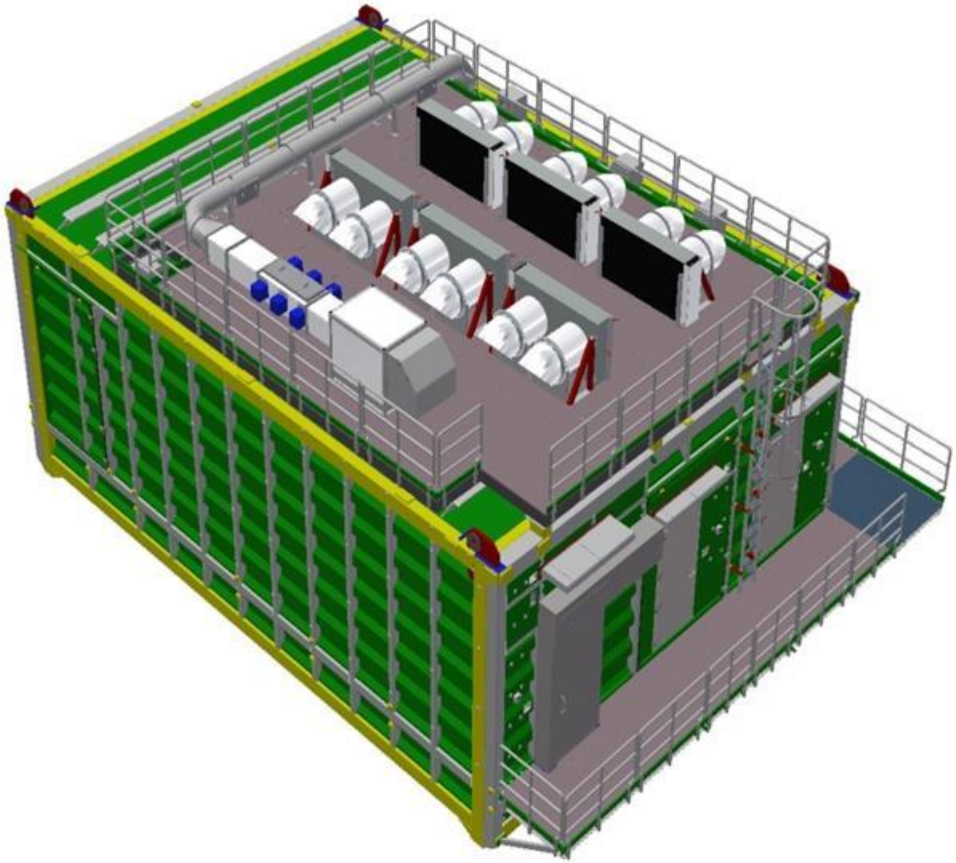
TUTU





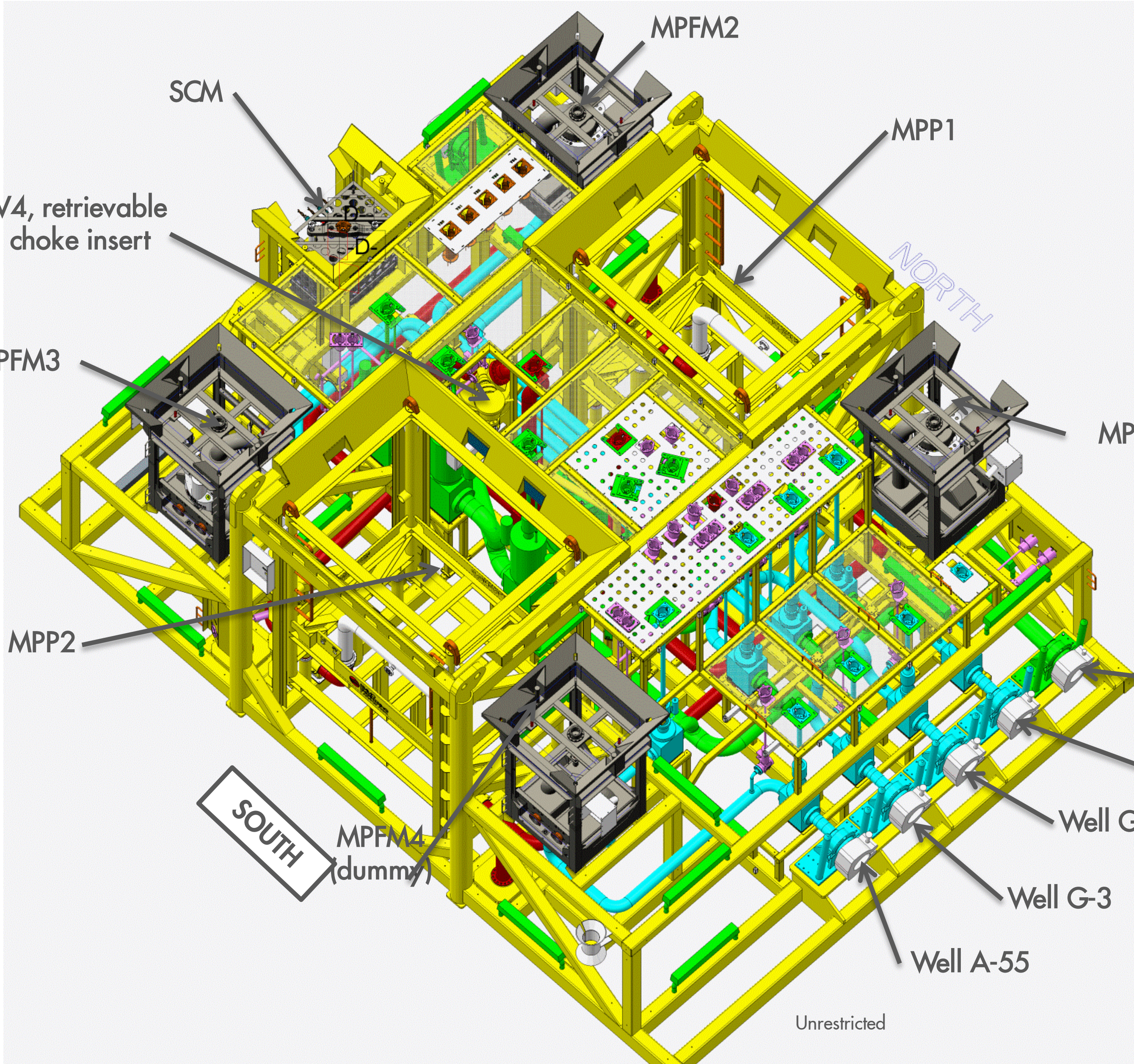
TOOLS

TOPSIDE - POWER CONTROL MODULE (PCM)



DRAUGEN SUBSEA PUMP: PROCESS CONTROL MODULE

PUMP STATION



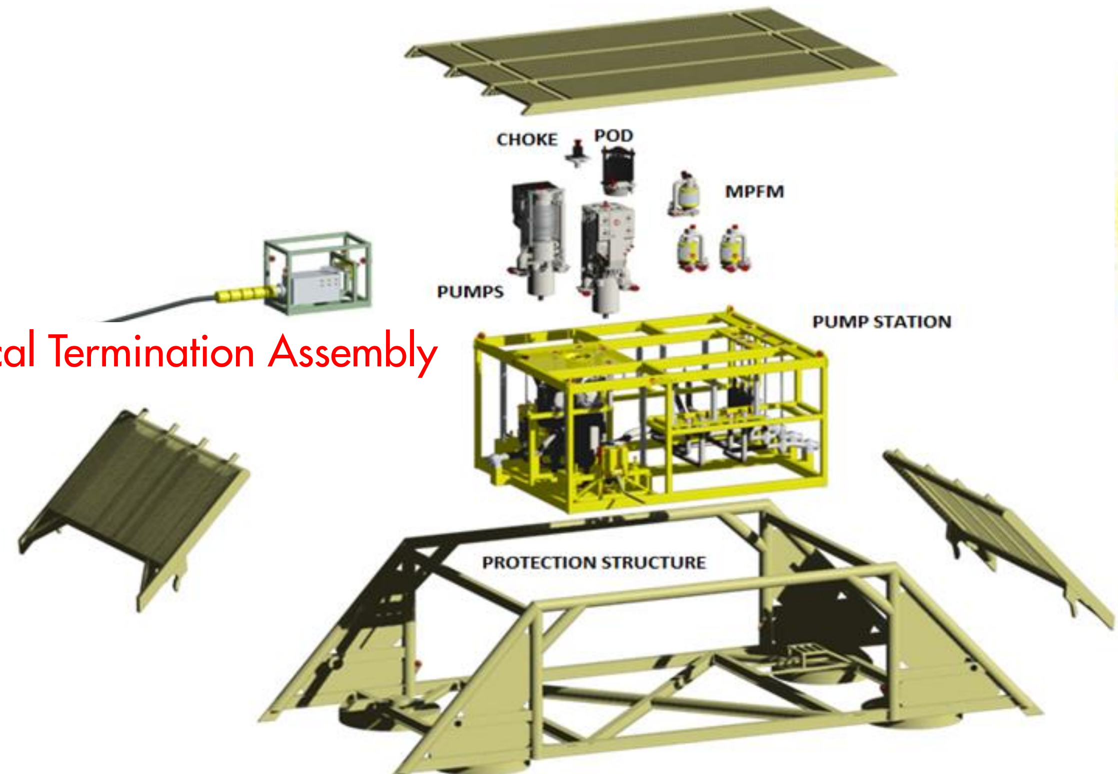
PUMPING SYSTEM SCOPE OF SUPPLY

Process Control Module

Topside Umbilical Termination Unit

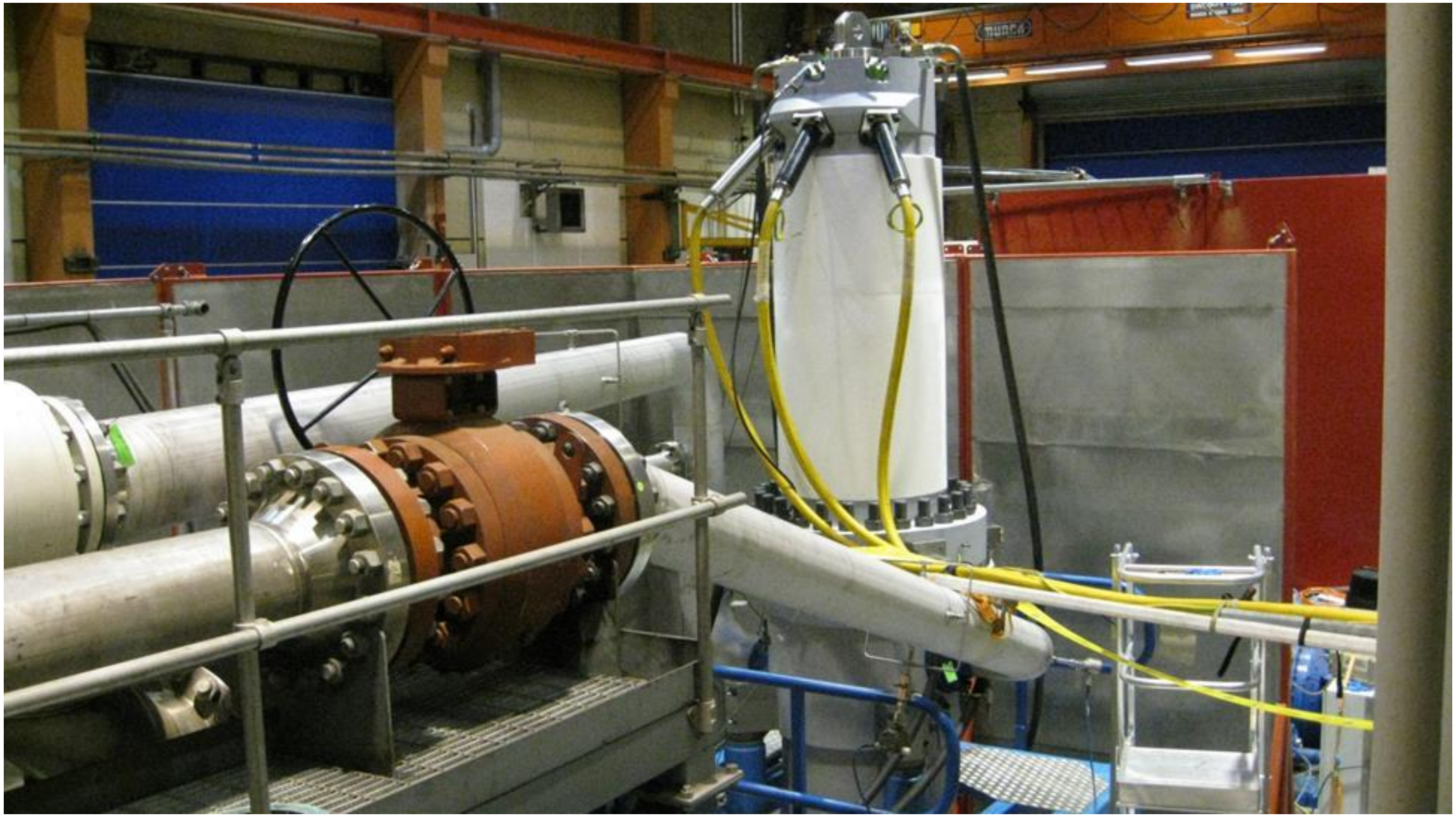
Hydr. TUTU | LV TUTU | FO TUTU | HV TUTU

Subsea Umbilical Termination Assembly



PUMP STATION INSTALLATION

PUMP TESTING



TESTING

ROV access testing

Hub cleaning tool stack-up test

Pump module stack-up test

Mock-up ROV access test

Test of Ocean Install shackle towards the Pump Station

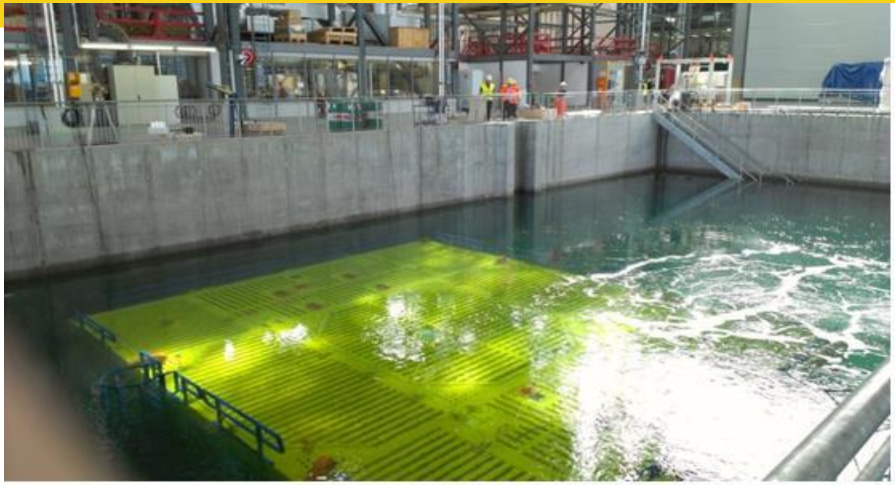
MV connector stack-up test

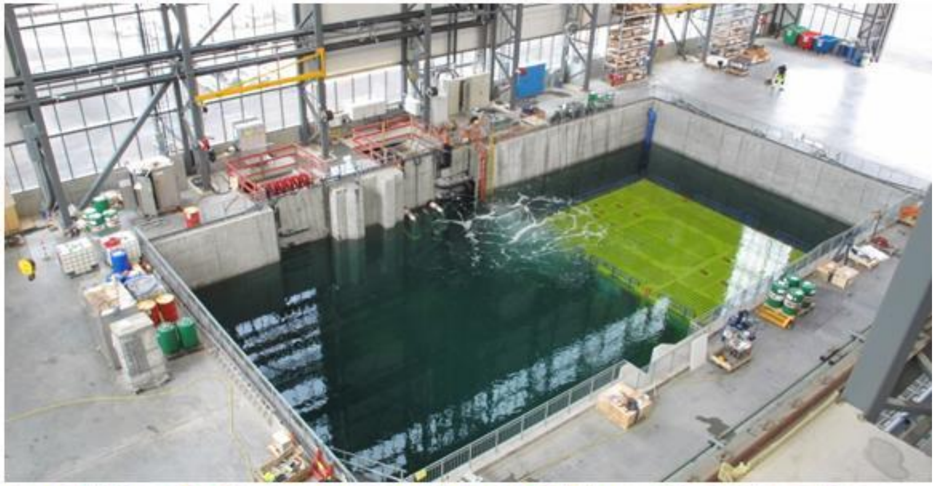
STACK UP PUMP STATION INTO PROTECTION STRUCTURE






TESTING AT HORSØY





4.0

TECHNOLOGY & INDUSTRY INITIATIVES ON SUBSEA BOOSTING

API 17N
Industry Initiatives

API RP 17N

- What is API RP 17N?
- Industry collaboration attempting to address a common approach Technology Readiness Level (TRL) and associated Technology Risk Categorization (TRC) for development of new technology
- Focus on assessment of modification of existing technologies/equipment to the project specific needs, not just new technologies
- Focus on assessment of new technologies already deployed, particularly with respect to reliability
- Present assessment in the form of a risk/readiness matrix
- References internal/external standards and codes

TRC definition with Shell interpretation

Table A.1—Technical Risk Categorization

	Technical System Scale and Complexity			Operating Envelope	Organizational Scale/Complexity
	Reliability	Technology	Architecture/ Configuration	Environment	Organization
Key Words	• Reliability requirements • Maintainability • Availability • Failure modes • Risk • Uncertainty	• Materials • Dimensions • Design life • Design concept • Stress limits • Temperature limits • Corrosion • Duty cycle	• Equipment • Layout • Interfaces • Complexity • Diver/ROV • Deployment/ intervention • Tooling	• Field location • Water depth • Seabed conditions • Reservoir conditions • Environmental loadings • Test location • Storage	• Location • Company • Contractor • Supply chain • Design • Manufacture • Install • Operate • Maintain
A (Very high)	**Reliability improvements (technology change):** A significant reliability improvement requiring change to the technology involved.	**Novel technology or new design concepts:** Novel design or technology to be qualified during project.	**Novel application:** Architecture/ configuration has not been previously applied by supplier.	**New environment:** Project is pushing environmental boundaries such as pressure, temperature, new part of world, severe meteorological conditions or hostile on land test location.	**Whole new team:** New project team, working with new suppliers in a new location.
B (High)	**Reliability improvements (design change):** Significant reliability improvement requiring change to the design but no change to the technology.	**Major modifications:** Known technology with major modifications such as material changes, conceptual modifications, manufacturing changes, or upgrades. Sufficient time remains for qualification. Non mature for extended operating environments.	**Orientation and capacity changes:** Significant architectural/ configuration modifications such as size, orientation and layout; changes fully reviewed and tested where viable. Large scale, high complexity.	**Significant environmental changes:** Many changes noted; extended and/or aggressive operating environment; risk requires additional review.	**Significant team changes:** Project team working with new supplier or contractor within supply chain; key technical personnel changes from previous project.
C (Medium)	**Minor reliability improvements:** Reliability Improvements requiring tighter control over quality during manufacture assembly and fabrication.	**Minor modifications:** Same supplier providing a copy of previous equipment with minor modifications such as dimensions or design life; modifications have been fully reviewed and qualification can be completed.	**Interface changes:** Interface changes, either with different equipment or control system changes; where appropriate, configuration has been tested and verified.	**Similar environmental conditions:** Same as a previous project or no major environmental risks have been identified.	**Minor team changes:** Small or medium organization; moderate complexity; minor changes in contractor/supplier and project team.
D (Low)	**Unchanged reliability:** No reliability improvements required, existing quality assurance (QA) and control is acceptable.	**Field proven technology:** Same supplier providing equipment of identical specification, manufactured at same location; provide assurance no changes have occurred through the supply chain.	**Unchanged:** Architecture/ configuration is identical to previous specifications; interfaces remain unchanged, with no orientation or layout modification.	**Same environmental conditions:** Same as recent project.	**Same team as previous:** Same project team, contractors, suppliers, and supplier's supply chain; applies throughout project life cycle.

TRL Definition

Table B.19—Definition of Technology Readiness Levels (TRLs)

	TRL	Development Stage Completed	Definition of Development Stage
Concept	0	**Unproven Concept** (Basic R&D, paper concept)	Basic scientific/engineering principles observed and reported; paper concept; no analysis or testing completed; no design history
Proof of Concept	1	**Proven Concept** (Proof of concept as a paper study or R&D experiments)	a) Technology concept and/or application formulated b) Concept and functionality proven by analysis or reference to features common with/ to existing technology No design history; essentially a paper study not involving physical models but may include R&D experimentation
Proof of Concept	2	**Validated Concept** Experimental proof of concept using physical model tests	Concept design or novel features of design is validated by a physical model, a system mock up or dummy and functionally tested in a laboratory environment; no design history; no environmental tests; materials testing and reliability testing is performed on key parts or components in a testing laboratory prior to prototype construction
Prototype	3	**Prototype Tested** (System function, performance and reliability tested)	a) Item prototype is built and put through (generic) functional and performance tests; reliability tests are performed including; reliability growth tests, accelerated life tests and robust design development test program in relevant laboratory testing environments; tests are carried out without integration into a broader system b) The extent to which application requirements are met are assessed and potential benefits and risks are demonstrated
Prototype	4	**Environment Tested** (Pre-production system environment tested)	Meets all requirements of TRL 3; designed and built as production unit (or full scale prototype) and put through its qualification program in simulated environment (e.g. hyperbaric chamber to simulate pressure) or actual intended environment (e.g. subsea environment) but not installed or operating; reliability testing limited to demonstrating that prototype function and performance criteria can be met in the intended operating condition and external environment
Prototype	5	**System Tested** (Production system interface tested)	Meets all the requirements of TRL 4; designed and built as production unit (or full scale prototype) and integrated into intended operating system with full interface and functional test but outside the intended field environment
Field Qualified	6	**System Installed** (Production system installed and tested)	Meets all the requirements of TRL 5; production unit (or full scale prototype) built and integrated into the intended operating system; full interface and function test program performed in the intended (or closely simulated) environment and operated for less than 3 years; at TRL 6 new technology equipment might require additional support for the first 12 to 18 months
Field Qualified	7	**Field Proven** (Production system field proven)	Production unit integrated into intended operating system, installed and operating for more than three years with acceptable reliability, demonstrating low risk of early life failures in the field

API 17N Interpretation: Risk (TRC) /Readiness (TRL) Matrix

Technical Risk Categorization	Very High Technical Risk / Unacceptable Reliability	A	N/A							
	High Technical Risk / Low Reliability	B	N/A							
	Medium Technical Risk / Moderate Reliability	C								
	Low Technical Risk / Acceptable Reliability	D	25	2		1				
			7	6	5	4	3	2	1	0
			Field Proven	**System Installed** (less than 3 years) or immature with respect to reliability	**System Tested**	**Environment Tested** New Technology, or Some Reconfiguration of Existing Technology	**Prototype Tested** New Technology or significant reconfiguration of existing technology	**Validated Concept**	**Proven Concept**	**Unproven Concept**
			Technology Readiness Level							

- Note: Numbers above are examples. Not a reference to Draugen system.

INDUSTRY INITIATIVES

<u>Longstep tie-back developments (>20 km)</u>

- Electrically heated lines
- Long step out power supplies (<120 km)
- Simplifying control system – onshore based system

<u>Standardisation</u>

-API 17X Recommended Practice on Subsea Pumping Systems

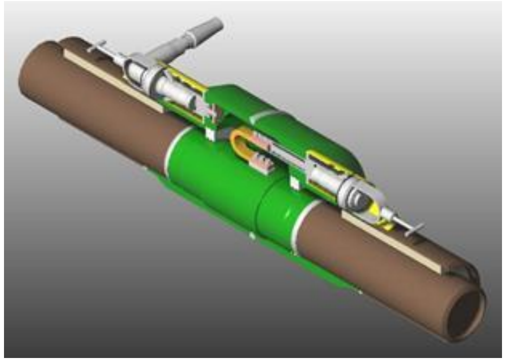
-Subsea Processing JIP – Standardization of Subsea Pumping.

<u>Building market competitiveness</u>

  - Pumping, higher pressures
  - Compression – Wet tolerance
  - Wet Compression – increasing the product range
  - Subsea water injection – Seabox (NOV)

LONGSTEP OUTS

- Electrically heated lines:
  - Electrical heat tracing (Lowest power usage, highest CapEx)
  - Wet insulation direct electrical heating
  - Pipe in pipe direct electrical heating



- Long step out power supplies
  - Onshore VSDs – 120 km & 12.5 MW vs.
  - Subsea VSD and switch gear (cable cost vs. subsea cost)
- Simplifying control system – onshore based system
  - Communication protocols for safe shore based control of subsea systems

BUILDING MARKET COMPETITIVENESS

Pumping

- OneSubsea one major vendor, lack of competition
- Qualifying FMC/Sulzer for the BC-10 project Brazil

Compression – Wet tolerance

- Man and GE furthering technologies to be tolerant to 95% GVF, 30% liquid w/w. Testing completed
- Wet Compression One Subsea dual drive axis axial compressor
  - WGC 4000 deployed for Statoil on Gulfaks
  - Developing WGC 6000, Testing. Chevon Gorgon project

5.0

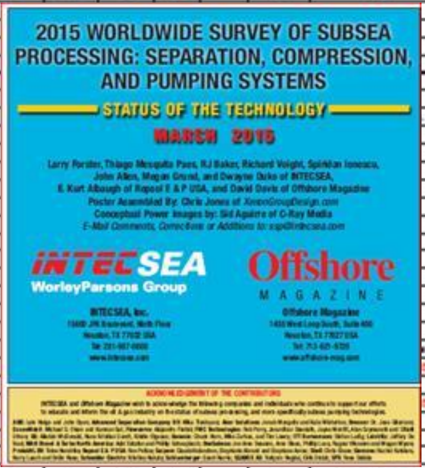
FIELD SCREENING OF SUBSEA BOOSTING

Technology Maturity, Field Screening Process

Proven Technology – 2 Million Running Hours

TABLE 1 – 2015 WORLDWIDE SURVEY OF SUBSEA GAS COMPRESSION, BOOSTING, WATER INJECTION, AND SEPARATION (1)(2) – As of Feb. 2015

PROCESSING DISCIPLINE	COUNT	FIELD OR PROJECT (Ordered by Start Date)	CURRENT STATUS	COMMENTS	OWNER/FIELD OPERATOR	REGION/BASINS	WATER DEPTH		TIEBACK DISTANCE		SYSTEM FLOW RATE (@LINE CONDITIONS)		DIFFERENTIAL PRESSURE		UNIT POWER (3)	TOTAL POWER DEMAND	GVF (5) GAS VOLUME FRACTION	SYSTEM PACKAGER
					COMPANY		Meters	Feet	Km	Miles	M³/Hr	MBOPD MMSCFD	BAR (4)	PSI (4)	MW	MW	% OF VOL.	COMPANY
SUBSEA GAS COMPRESSION	1	DEMO 2000	Q	Statoil K-Lab Test	Statoil	Offshore Norway									3.00		n/a	OneSubsea
	2	Ormen Lange Gas Compression Pilot	Q	Testing 1 train @ Nyhamna, Norway	Shell	Offshore Norway	850	2,821	0.0	0.0	25,000	3776	60.0	870	12.50	58.00	n/a	Aker Solutions
	3	Asgard - Midgard & Mikkel Fields	M	Subsea Gas Compression	Statoil	Offshore Norway	300	984	40.0	25.0	40,000	6,042	60.0	870	11.50	34.40	n/a	Aker Solutions
	4	Gullfaks South Brent (28)	M	Subsea Wet Gas Compression	Statoil	Offshore Norway	135	443	15.5	9.7	9,600	1450	30.0	435	5.00	10.00	95%	OneSubsea
	5	Ormen Lange Gas Compression	C	Subsea Gas Compression	Norske Shell	Offshore Norway	850	2,821	120.0	75.0	50,000	7553	60.0	870	12.50		n/a	TBA
	6	Troll	C	Subsea Gas Compression	Statoil	Offshore Norway	340	1,116	4.0	2.5								
	7	Peon	C	Subsea Gas Compression	Statoil	Offshore Norway	385	1,263	TBD	TBD								
	8	Snohvit	C	Subsea Gas Compression	Statoil	Barents Sea	345	1,132	143.0	88.4								
	9	Shtokman	C	Subsea Gas Compression	Gazprom	Barents Sea	350	1,148	565.0	351.1								
SUBSEA BOOSTING (NOTE 1. SEABED & RISER ONLY, NOTE 2. EXCLUDES IN-WELL ESP)	1	Prezioso (20)	A	MPP at Base of Platform	AGIP	Italy	50	164	0.0	0.0	65.0							
	2	Draugen Field	A	SMUBS Project, 1 MUTUP	A/S Norske Shell	Offshore Norway	270	885	6.0	3.7	1950							
	3	Lufeng 22/1 Field (9) (19)	A	Tieback to FPSO	Statoil	South China Sea	330	1,083	1.0	0.6	6750							
	4	Machar Field (ETAP Project)	A	Hydraulic Drive MPP	BP Amoco	UK North Sea	85	277	35.2	21.9	1,100.0							
	5	Topacio Field	O	1 x Dual MPP System	ExxonMobil	Equatorial Guinea	550	1,805	8.0	5.0	9460							
	6	Ceiba C3 + C4	O	Phase 1 SS MPP Project	Hess	Equatorial Guinea	750	2,461	7.0	4.3	6000							
	7	Jubarte EWT	A	Riser BH to Seillean drillship	Petrobras	Espirito Santo Basin	1,400	4,593	1.4	0.9	1450							
	8	Ceiba Field (FFD)	O	Full Field Development (FFD)	Hess	Equatorial Guinea	700	2,297	14.5	9.0	2,500.0							
	9	Mutineer/Exeter	O	2 x Single MPP Systems	Santos	NW Shelf, Australia	145	476	7.0	4.3	1,200.0							
	10	Lyell (Original Install)	A	SS Tieback to Ninian South	CNR	UK North Sea	146	479	15.0	9.3	1,100.0							
	11	Navajo (17)	LM	ESP in Flowline Riser	Anadarko	US GOM	1,110	3,642	7.2	4.5	24.0							
	12	Jubarte Field - Phase 1	A	Seabed ESP-MOBO, Uses BCSS (14)	Petrobras	Espirito Santo Basin	1,350	4,429	4.0	2.5	1200							
	13	Brenda & Nicol Fields	O	Multifield with 1 MPP	Premier Oil	UK North Sea	145	476	8.5	5.3	8000							
	14	King (7) (13)	A	SS Tieback to Marlin TLP	Freeport McMoRan	US GOM	1,700	5,578	29.0	18.0	4965							
	15	Vincent	O	Dual MPP System	Woodside	NW Shelf, Australia	475	1,558	3.0	1.9	2,400.0							
	16	Marlim	A	SBMS-500 SS Field Test	Petrobras	Campos Basin	1,900	6,234	3.1	1.9	5000							
	17	Golfinho Field	O	Seabed ESP-MOBO, Uses BCSS (14)	Petrobras	Espirito Santo Basin	1,350	4,429	11.0	6.8	1460							
	18	Azurite Field	A	Dual MPP System	Murphy Oil	Congo, W. Africa	1,308	4,290	3.0	1.9	3500							
	19	Golfinho Field	O	MOBO BCSS (ESP) Caisson (14)	Petrobras	Espirito Santo Basin	1,350	4,429	5.0	3.1	1460							
	20	Espadarte (Field Trial)	A	Horizontal ESP on Skid	Petrobras	Brazil	1,350	4,429	11.5	7.1	1250							
	21	Parque Das Conchas (BC 10) Phase 1 (23)	O	Caisson/Artificial Lift Separation	Shell	Campos Basin	2,150	7,054	9.0	5.6	1650							
	22	Parque Das Conchas (BC-10) Phase 2 (23)	O	2 additional ESP systems	Shell	Campos Basin	2,150	7,054	9.0	5.6	1650							
	23	Jubarte Field - Phase 2 (25)	O	Tieback to FPSO P-57, Uses BCSS (14)	Petrobras	Espirito Santo Basin	1,400	4,593	8.0	5.0	1,325.0	200	200	3,000	1.20		35-40%	Aker Solutions
	24	Cascade & Chinook (6)	LM	Skid BCSS - Horizontal ESP on Skid	Petrobras	US GOM	2,484	8,150	8.0	5.0	1350	20	220.0	3,191	1.10		10%	FMC Technologies
	25	Barracuda (32)	O	SS MP High Boost Pump System	Petrobras	Campos Basin	1,040	3,412	10.5	6.5	2800	42	70.0	1,015	1.50		35-40%	OneSubsea
	26	Montanazo & Lubina	LM	Single MPP System	Repsol	Mediterranean	740	2,428	12.3	7.6	80.0	12	65.0	943	0.23		10%	OneSubsea
	27	Schiehallion	LM	2 x Dual MPP Systems	BP	UK, West of Shetland	400	1,312	4.0	2.5	2,700.0	408	26.0	377	1.00		74%	GE/OneSubsea
	28	CLOV (22)	LM	Subsea MPP System	TOTAL	Angola, Blk 17	1,170	3,839	11.0	6.8	6600	100	45.0	652	2.30		50%	OneSubsea
	29	Jack & St. Malo	LM	3 x Single SPP Systems (JSM)	Chevron	US GOM	2,134	7,000	35.0	21.0	1,116.0	160	241.3	3,500	3.00		10%	OneSubsea
	30	Lyell Retrofit	O	MPP Retrofit System - Tieback to Ninian	CNR	UK North Sea	145	476	7.0	4.3	7000	106	21.0	305	1.00		97%	OneSubsea
	31	Gir Ri (Girassol) (27)	M	Field Expansion Project	Total	Angola, Blk 17	1,350	4,429	18.0	11.2	6000	91	130.0	1,885	2.50		25-35%	OneSubsea
	32	Draugen Field	M	2 x Dual Helicoaxial MPP stations	A/S Norske Shell	Offshore Norway	250	[illegible]	4.0	2.5	1,710.0	253	47.5	689	2.30		15-21%	OneSubsea
	33	Julia	M	SS Tieback with Dual SPP Systems	ExxonMobil	US GOM	2,287	7,500	27.2	17.0	331	50	175.0	2,550	3.00		10%	OneSubsea
	34	Moho Phase 1bis	M	Brownfield Tieback to Alima FPU	Total	Congo, W. Africa	650	2,133	6.7	4.0	400	60	133.5	1,935	3.50		40%	OneSubsea
	35	Atlanta Field	C	Caisson Application	QGEP (26)	Santos Basin, Blk BS-4	1,500	4,922										TBD
	36	Stones	C	Single Phase HPHT Pump System	Shell	US GOM	2,927	9,600	5.0	3.1	TBD	TBD	TBD	TBD	TBD		<10%	TBD
	37	Appomattox	C	MPP in Future Phases	Shell	US GOM	2,222	7,290										
	38	Parque Das Baleias	M	Horizontal ESP on Skid (14)	Petrobras	Espirito Santo Basin	1,500	4,922	10.0	6.2	1250	19	100	1,450	1.20		10-25%	FMC Technologies
	39	Vigdis	C	Subsea Boosting of existing wells	Statoil	Offshore Norway	280	919	6.5	4.1			50.0	725	2.30	2.30	35-40%	TBA



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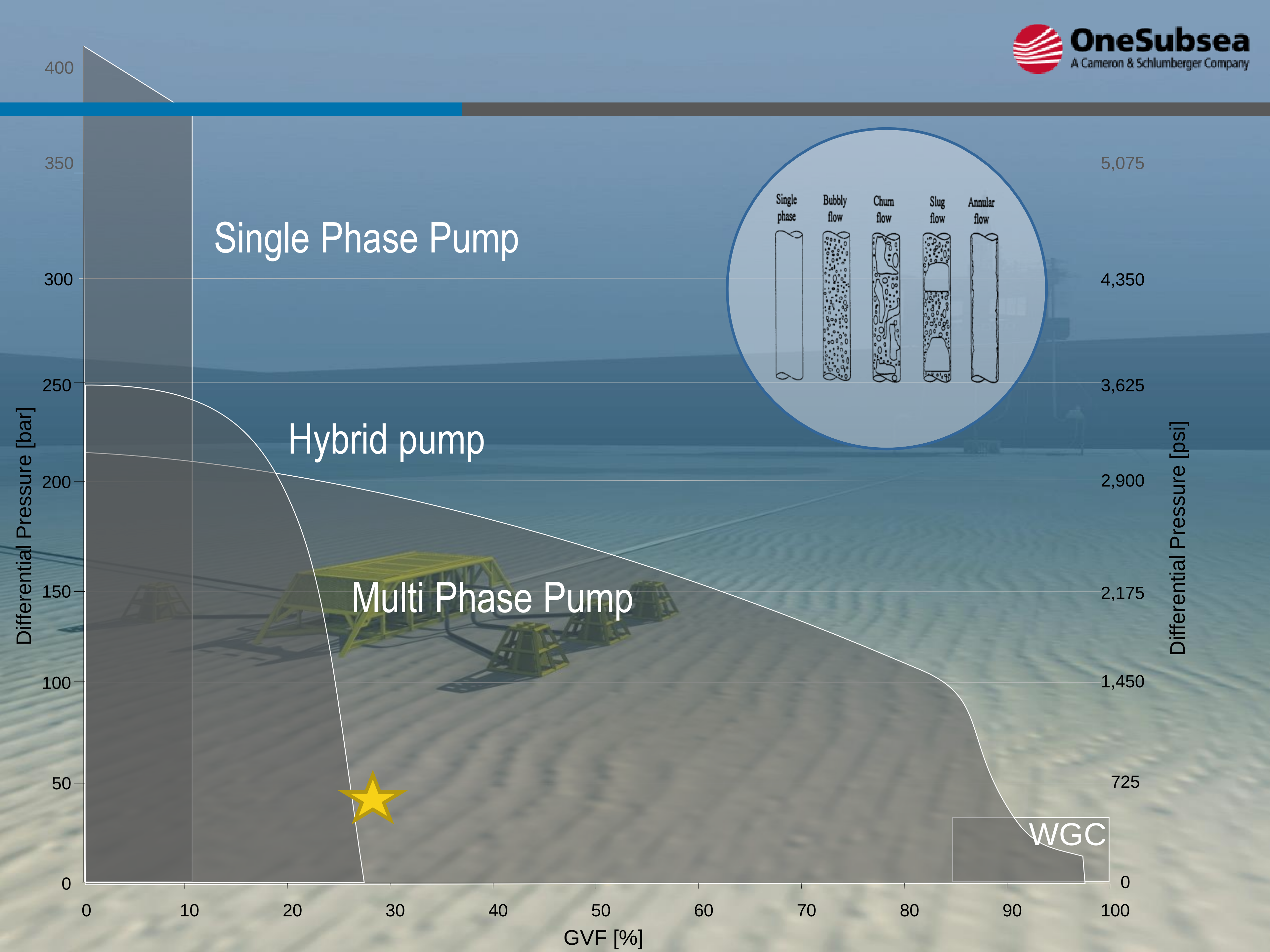

OneSubsea
A Cameron & Schlumberger Company
Single Phase Pump
Hybrid pump
Multi Phase Pump
WGC
Single phase
Bubbly flow
Churn flow
Slug flow
Annular flow
Differential Pressure [bar]
400
350
300
250
200
150
100
50
0
Differential Pressure [psi]
5,075
4,350
3,625
2,900
2,175
1,450
725
0
0
10
20
30
40
50
60
70
80
90
100
GVF [%]

OneSubsea Design Pressure Milestones

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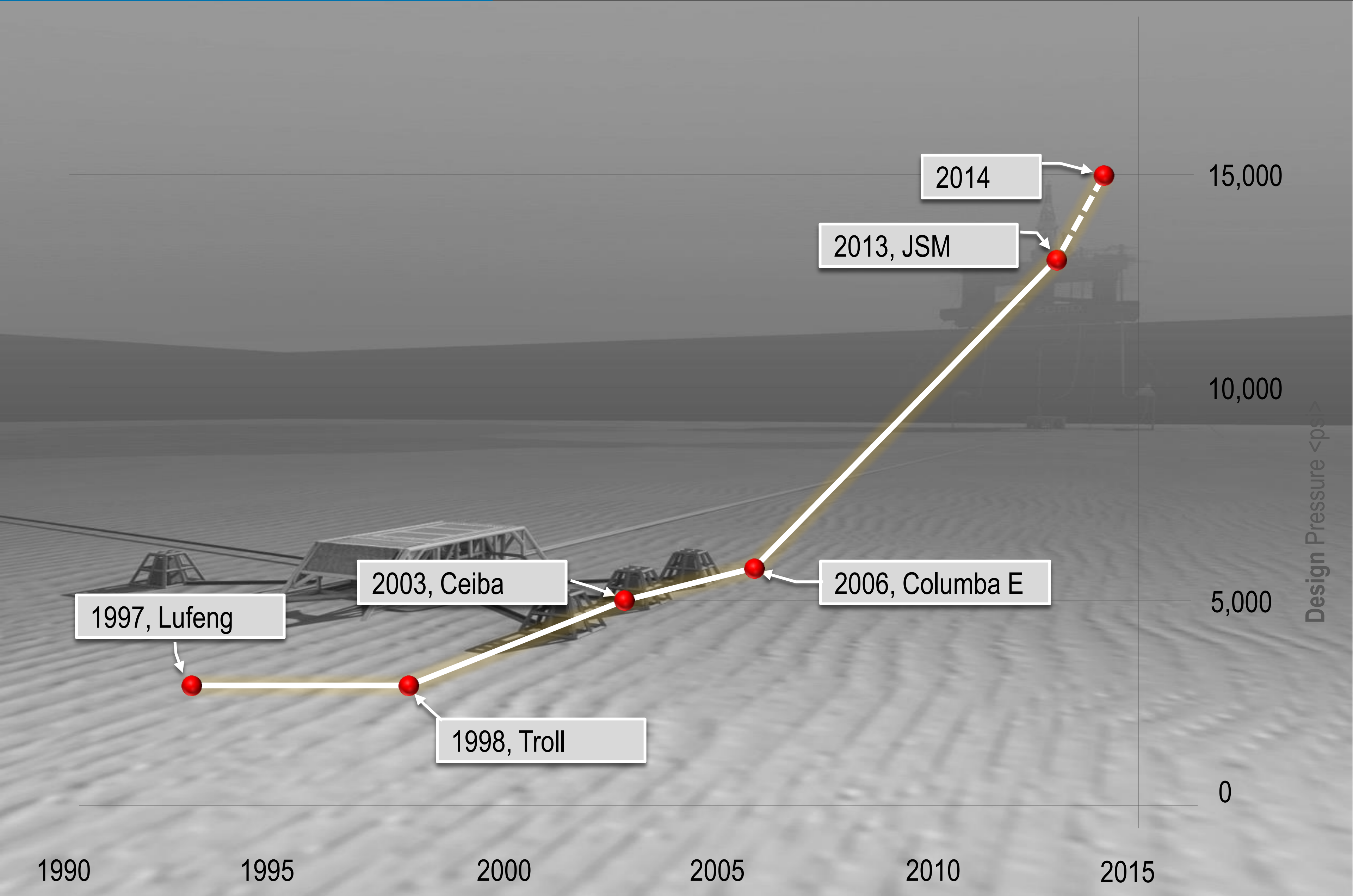
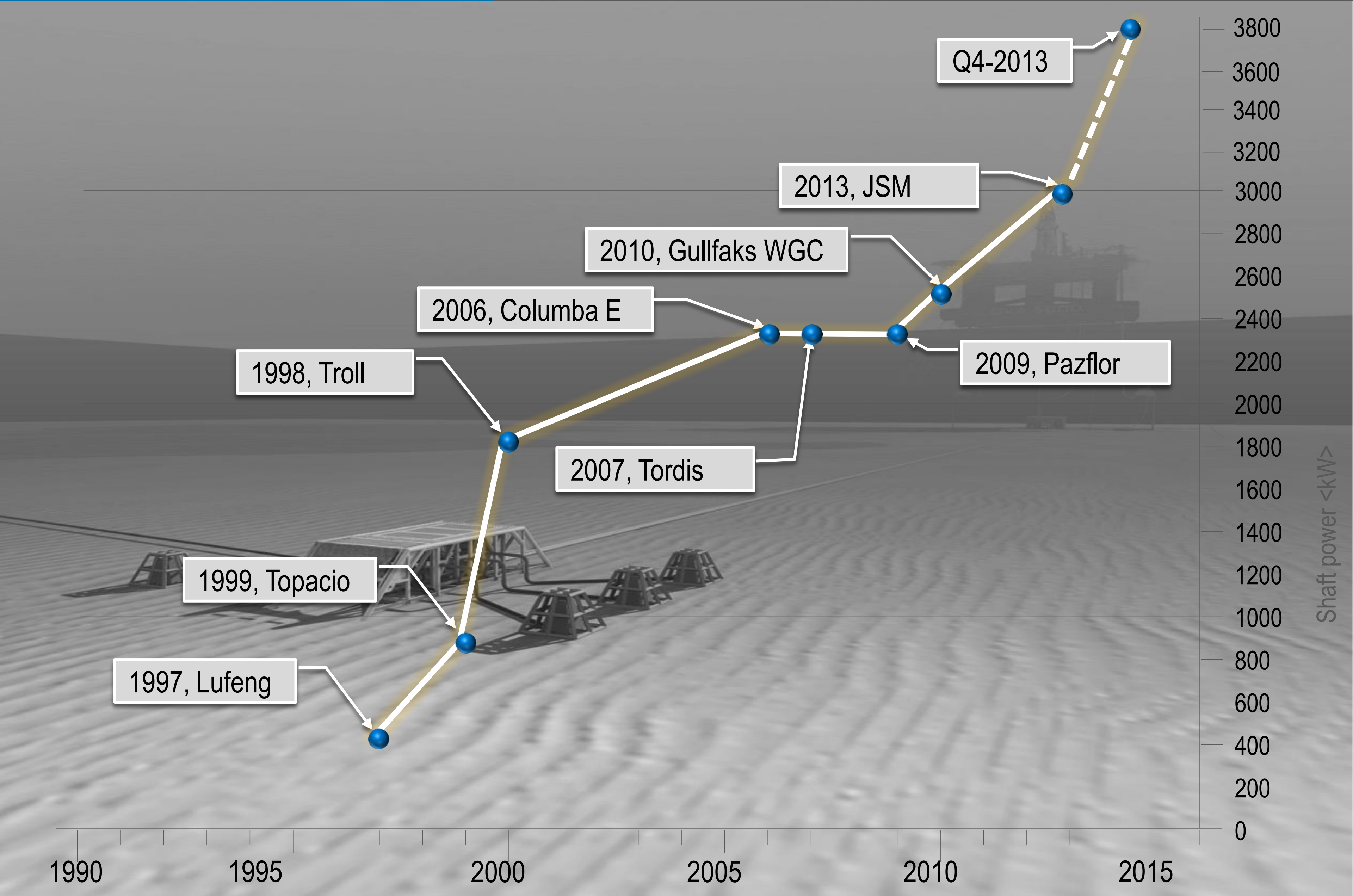


OneSubsea Motor Shaft Power Mile Stones



OneSubsea Water Depth Milestones

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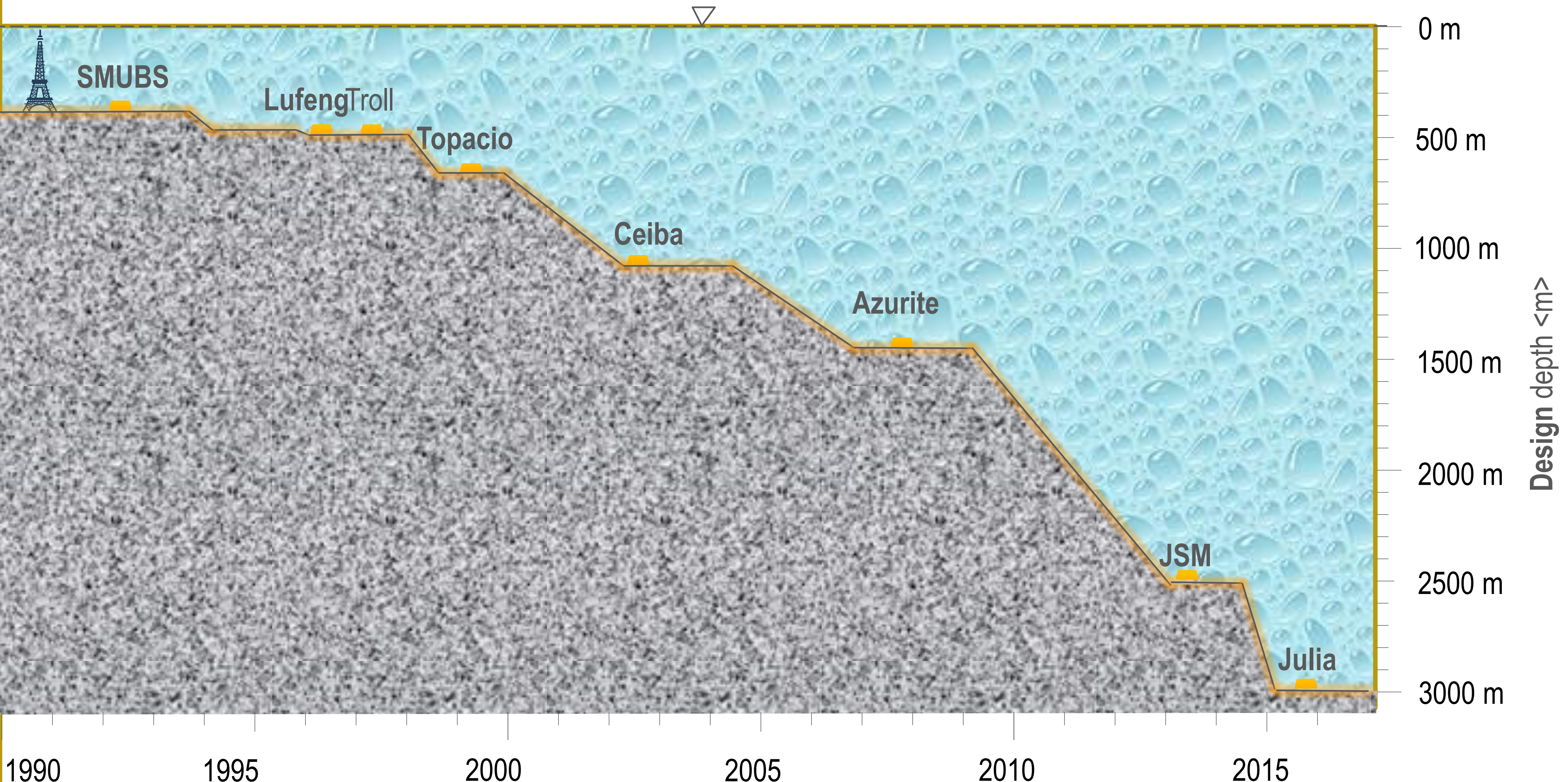
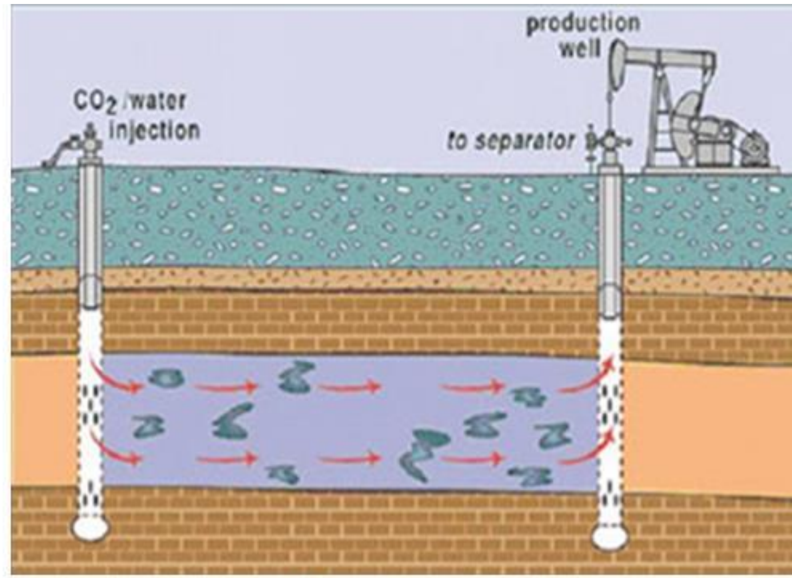


Reservoir Development Concept

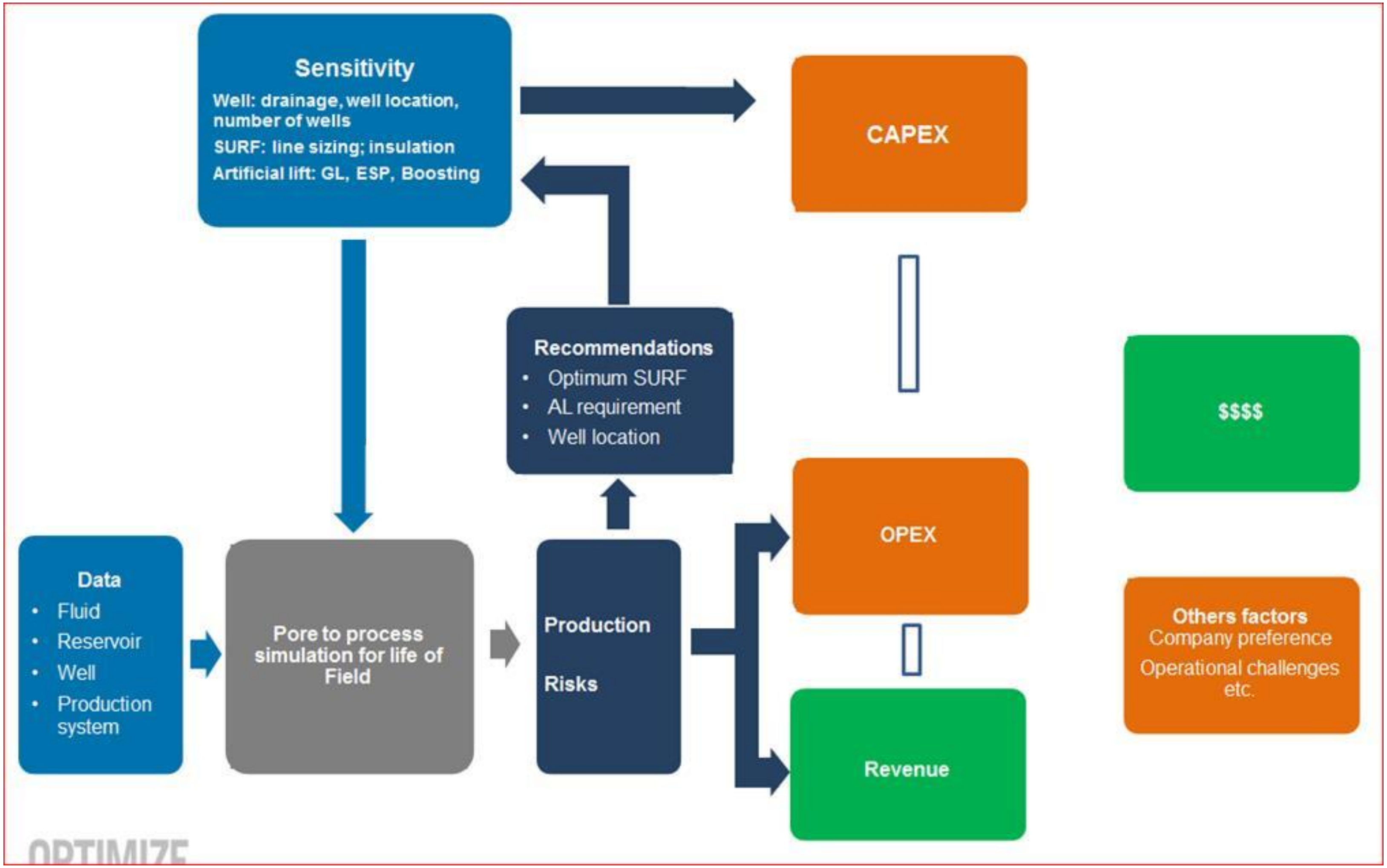
- EOR
  - Reservoir
    - Pressure Maintenance
      - Water Injection
      - Gas Injection
    - Fluid Displacement
      - CO2/Chemical/WAG
  - Production System
    - Back Pressure Reduction
      - Production system sizing
      - Gas Lift
      - ESP
      - Multiphase boosting



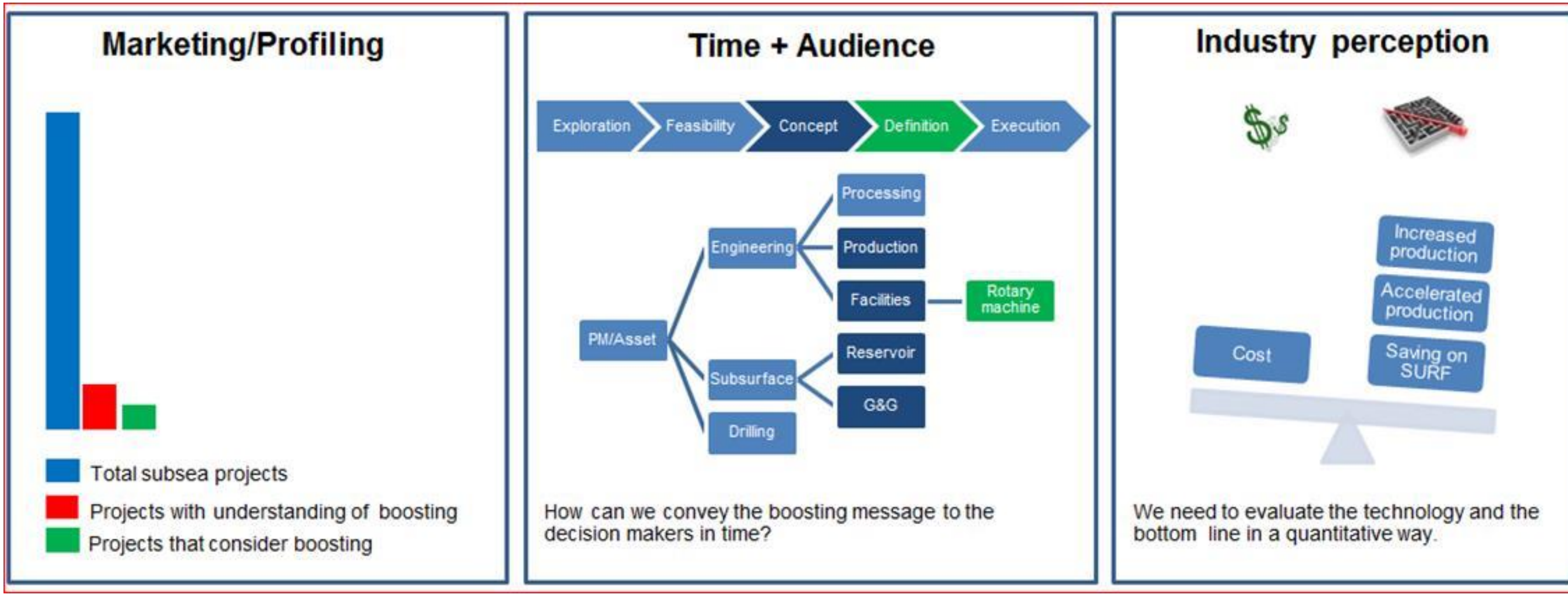
High level Comparison of typical Subsea Fields EOR methods

	Gas/Water/WAG Injection	Boosting	Gas Lift	ESP
Location	Injection Well	Wellhead Riser Base	Downhole Riser Base	Downhole
Pros	• Could reduce alternative investments (Prod. Wells, Flow lines, risers and topside equipment) • High flexibility when injecting into multiple reservoirs • Disposal produced water / reduce topside cleaning requirements • Combine with artificial lifts	• Very high volume capability • Effective on long tiebacks, requires smaller pipeline sizes • Positive effect on flow assurance • Can be shared by multiple wells/manifolds • High reliability and low intervention costs	• Excellent flexibility in injection/production rate • Excellent gas handling • Excellent sand and solids handling • No advanced subsea rotating equipment is required.	• High volume/rate capability • Wide production rate range between applications. • Effective on long tiebacks • Positive effect on flow assurance
Cons	• Large topside investments Topside Water Injection System including pump with filter, de-aerator, piping, valves, etc. • Platform modifications/extensions, installation, hook-up and commissioning work. • Weight and space constraints • High pressure injection pipelines • Extra Wells cost	• High cost per unit • Not economical for very small fields • Fewer applications compared with Gas Lift/ESP • Limited GVF range	• Compression cost is high and compressor must be reliable • Gas delivery line can be expensive • Fair operating efficiency, but poor for intermittent gas lift. • Tend to cause or increase flow assurance issues • Limited increase of production rates • Less effective in deep water • Not effective on long tie-backs	• Narrow production rate range for a specific application • Reliability is a major issue • Poor solids handling • Poor gas handling (without inlet gas separators). • High intervention frequency and cost • Only a per well application

Pore to Process Evaluation Involving Artificial Lift



Evaluation of Subsea Boosting



SCREENING OPPORTUNITIES

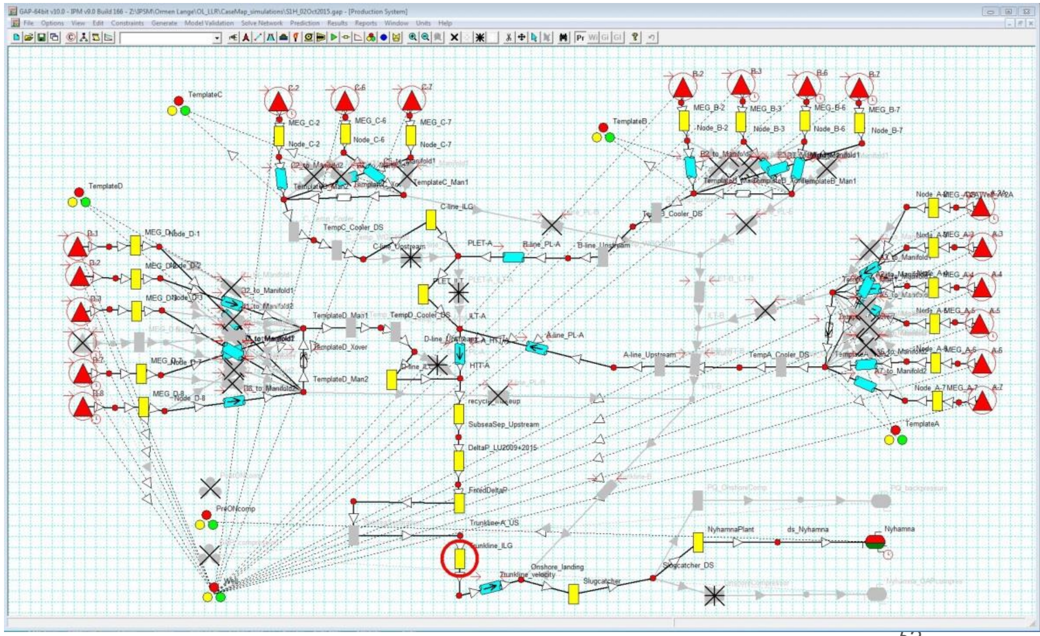
- Project economics requires: CapEx, OpEx and **Production profiles**
- Generally Reservoir Engineers are given surface PQ curves from which predict the impact of different surface options on reservoir production, from which to produce a profile from
- This is a limited approach:
  - Poor accuracy
  - Limited functionality, insensitive to compositional changes
  - Requires fixed water cuts & GORs
  - Difficult to model constraints e.g. compressor curves etc.
  - Etc…

PRODUCTION SYSTEM MODELLING

- Integrated Production System Modelling
- Shell uses PTEX's Resolve software that links together and optimises:
  - GAP – surface network
  - Prosper - well
  - MoRes –subsurface

Coupled with:

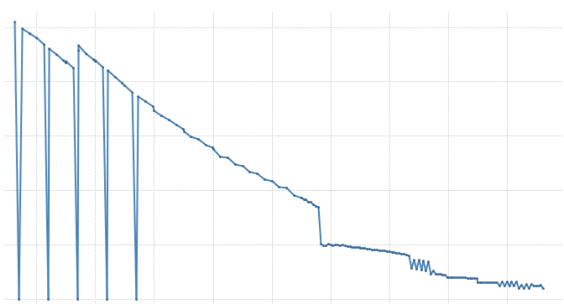
- Equipment Design
- Availability modelling
- Routing Logic



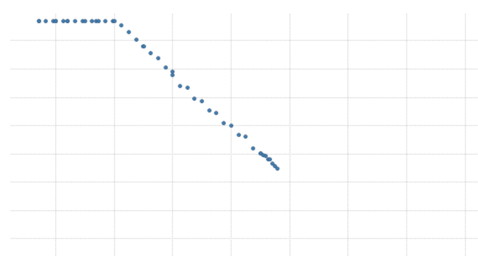
OUTCOME

- No endless iteration with Reservoir Engineering
- Quality of information has been significantly approved, able to assess between different options
- Perform senstivity analysis: equipment sizing, uncertainities, availability, routing, project timing etc.
- System analysis, understanding what are the governing constraints and what impact of changing them

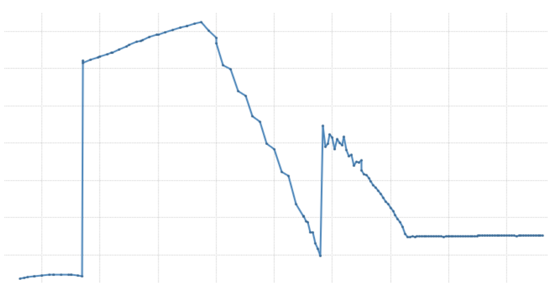
Production Profile



Compressor Power



Velocity Constraint



Q & A

Have a Safe Day