Maximizing gas recovery in the SNS sector by gas well deliquification and produced water re-injection

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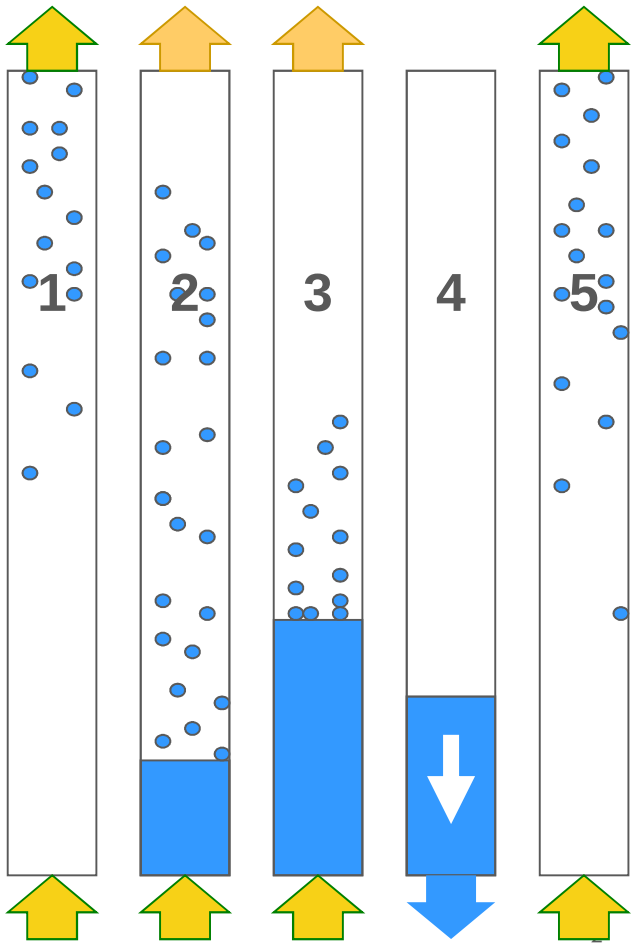
Agenda

- *ONEgas – Past, present and future*
- *Deliquification methods in ONEgas - Southern North Sea (SNS)*
- *Velocity string experiences SNS*
- *Continuous Foam (CF) experiences*
- *Gas Well Deliquification (GWD) Challenges*
- *Conclusions*

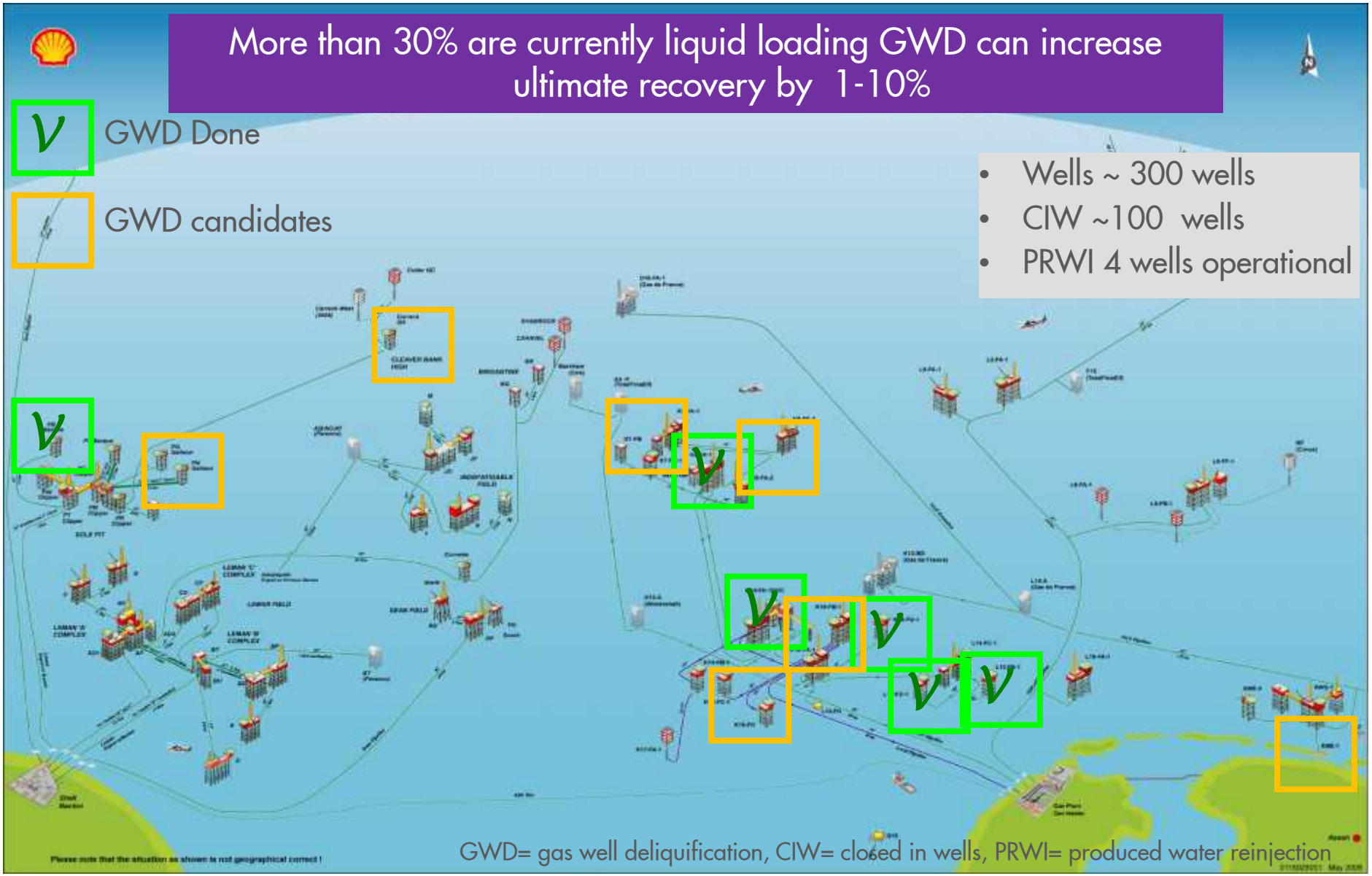
***LL**= when Q decreases below Qmin, **liquid loading** cycle starts and production drops sharply*

1. $Q > Q_{min}$ ⇔ Gas and liquid are both produced to surface
2. $Q < Q_{min}$ ⇔ Liquid accumulates in wellbore
3. $Q < Q_{min}$ ⇔ Bottom hole pressure increases, hence Q decreases until gas flow stops
4. $Q = 0$ ⇔ Liquid drains away and near-wellbore pressure re-charges
5. $Q > Q_{min}$ ⇔ Well starts flowing again



ONEgas – Past, Present and Future

More than 30% are currently liquid loading GWD can increase ultimate recovery by 1-10%



- Wells ~ 300 wells
- CIW ~100 wells
- PRWI 4 wells operational

GWD= gas well deliquification, CIW= closed in wells, PRWI= produced water reinjection

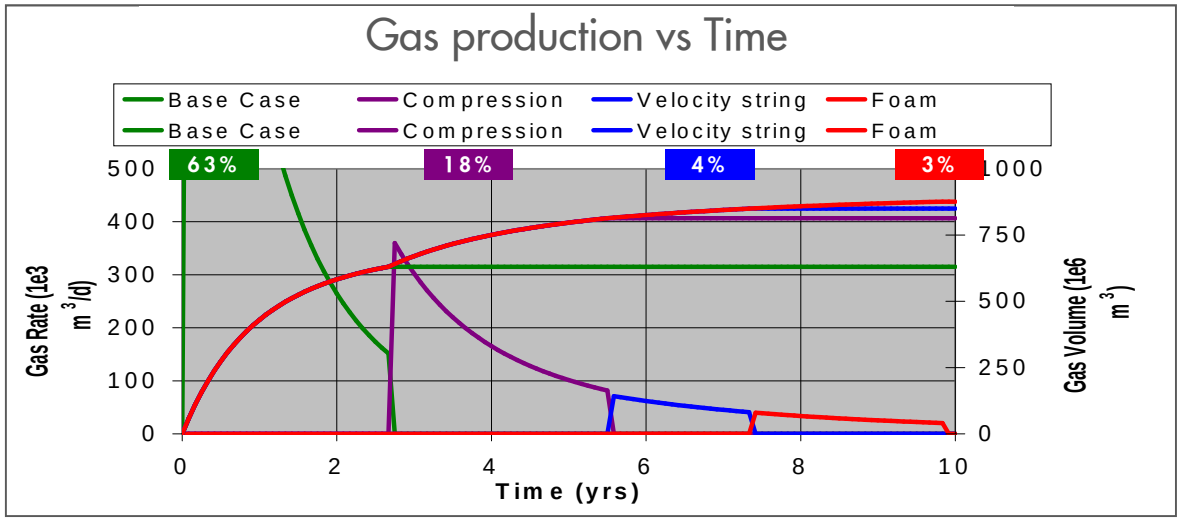
Shell

Main Deliquification Methods in SNS

- *Inflow:*
  - *Stimulation (perforating, acidizing, fracturing),*
  - *Water shut-off (WSO),*
  - *Fresh water soak/squeeze (salt),*

  Note: inflow optimization in 7 wells in offshore-NL delayed LL by 2-3 years (2015)

- Outflow:
  - Intermittent production IP (well cycling)
  - Reduce FTHP *(compression, surface debottlenecking)*
  - Reduce tubing size *(velocity string)*
  - Increase water carrying capacity *(batch Foam or CF + PWRI well)*
  - *Cleanout (CT, bailing)*



Main Deliquification Methods in SNS Cont.

Velocity String

- *OD 2 3/8" /2 7/8" VS hung off below the SSSV to top of perfs*
- *LL rate reduced from ~4 to 1.5 mmscf/d, < WGR 50 bbl/MMscf (5" tubing)*
- *Candidates have 'high=not good' Darcy inflow factor A= (>~40 bar2/e3 m3/d)*
- *To date 21 VS installations in Leman, Barque and K14, K15 , L13*

Capillary & batch Foam

- *Capillary string installed inside the tubing down to above the perforations*
- *LL rate as low as 0.9 MMscf/d , < WGR 100 bbl/MMscf, low CGR*
- *Candidates have 'low=good' Darcy inflow factor A= (<~20 bar2/e3 m3/d), vel. ~100 ft/sec*
- *Since early 2006, batch foaming to unload/kick of wells*
- *Since 2012, 12 wells on CF on 4 manned installations, 3.5 BCF gains (till 2015)*

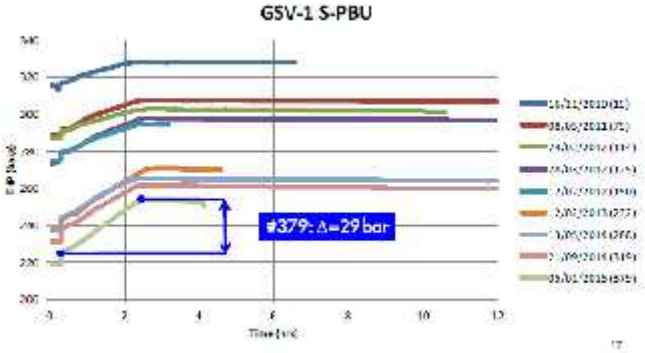
	SNS UK	SNS NL	ONEGas Total
Actual to date 2016			
Velocity strings (#)	**8**	**13**	**21**
Continuous Foam (#)	**5**	**7**	**12**
Plan – next 5 year plan			
Velocity strings (#)	**5**	**1**	**6**
Foam (#)	**10**	**12**	**22**

Deliqification Technology in Development

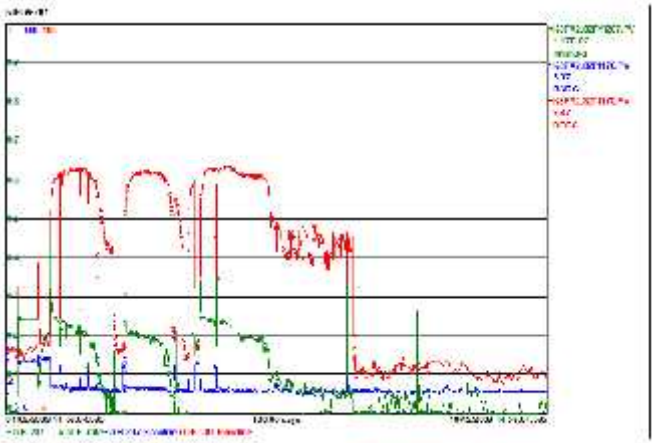
- *Future Technology in development*
  - *SURPRISE (surface pressure is excellent) software -Use Surface PBU Records to Calculate WGR and Darcy Coefficient in determining GWD selection (Shell software)*
  - *Automated Intermittent production –Use Flowing Wellhead Temperature as Proxy for Gas Rate to optimize well cycle*

Other:

- *Enhanced Gas Recovery EGR project - maximize recovery of mature fields by N2 injection (De Wijk Onshore) - Ongoing*
- *Deep gaslift Annerveen NL– Ongoing NAM Onshore*
- *Water lift downhole pump Coevorden NL– Successfully tested Q3 2014 in NAM Onshore*



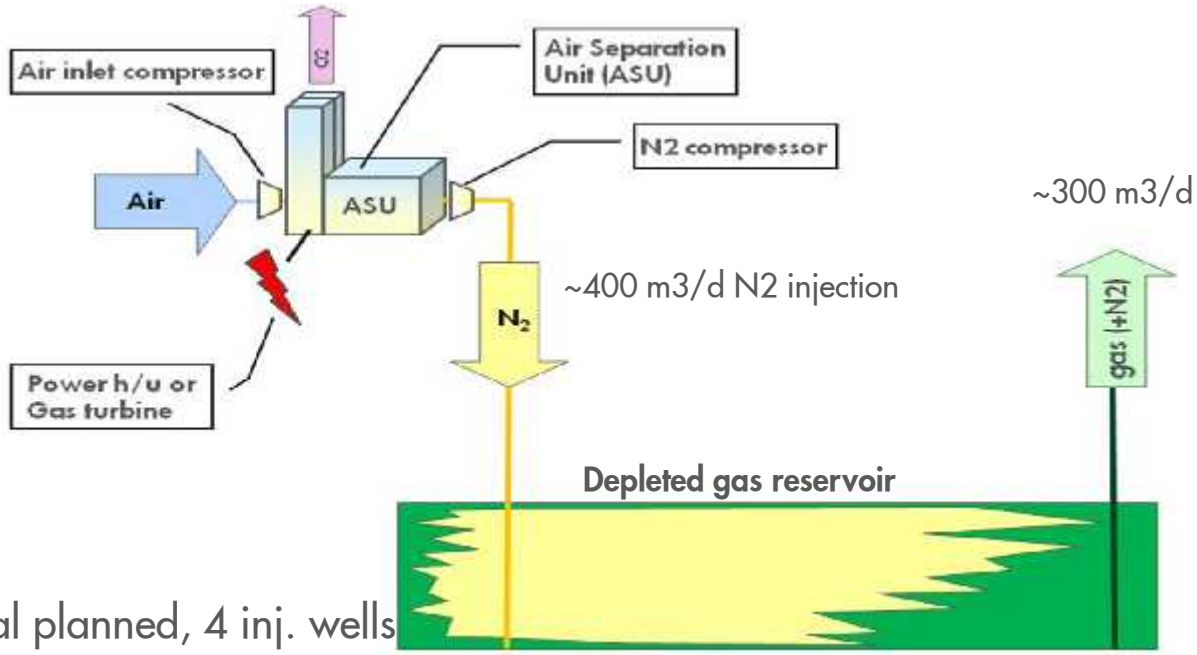
SURPRISE



T-Q Intermittent production

De Wijk (Onshore NL) - Maximize recovery of mature fields

- EGR schematic:



- EGR in DeWijk
  - Injection: 2013-2028
  - Status
    - N2 inj.: ~20% of total planned, 4 inj. wells
    - EGR prod.: ~10% of planned (time lag effect)
    - Incremental 1.0 Bcm
- De Wijk observations
  - liquid loaded well revived
  - response in nearby wells: as modelled (rate & N2 cut)
  - response in distance wells: as modelled (none yet or weak)

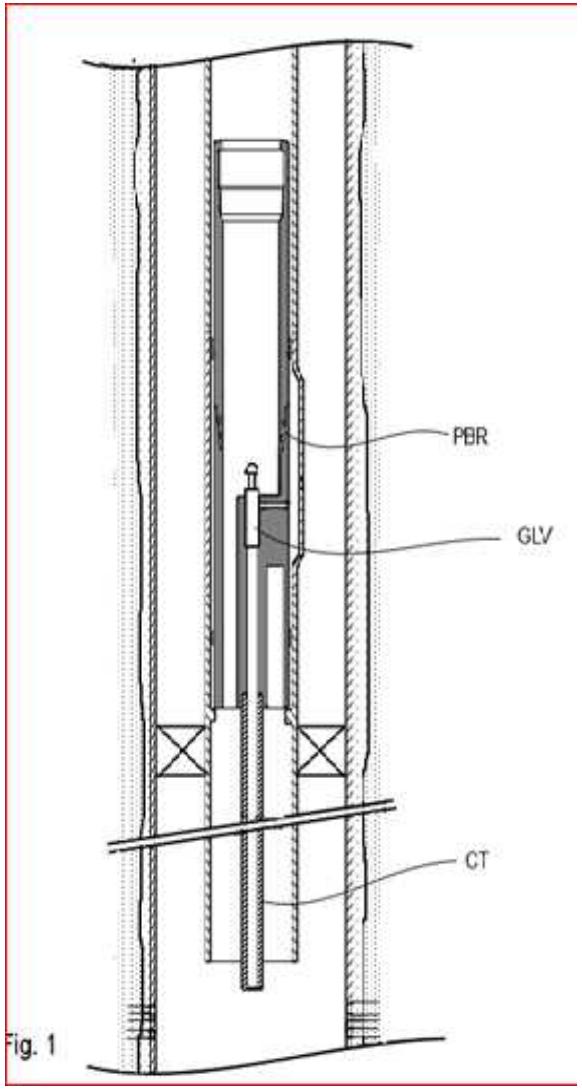
Annerveen Gas Field (Onshore NL) - Gas-Lift Dip Stick

- Initial field Pressure: 349 bara, year 1967
- OGIIP : 73.3 Bcm
- Gp: 71.1 Bcm (01.01.2014)
- Reservoir pressure: ~10 bar, 3 stage compression
- Developed by 15 wells in 3 clusters
- Wells in liquid loading region

Annerveen Deep gas lift project:

- Dry gas-lift in 6 wells was selected as most attractive and feasible
- Retrofit dip-stick was developed in-house to achieve deep injection (no retrofit solutions on the market)
- Incremental ~0.5 Bcm
- Gas-lift cost was reduced by (re-)using existing surface infrastructure
- Gas-Lift is applied to reduce abandonment pressure of gas field with <~10 bar

Retrofit assembly schematic



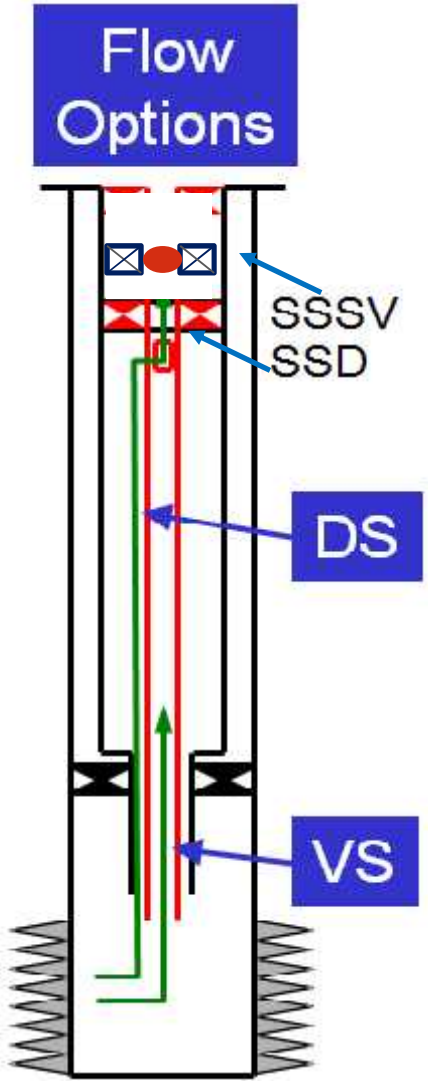
Status: Dip stick designed internally, feasibility confirmed by C&WI, patent filed (B. Lugtmeier 2014)

Velocity String Experience SNS

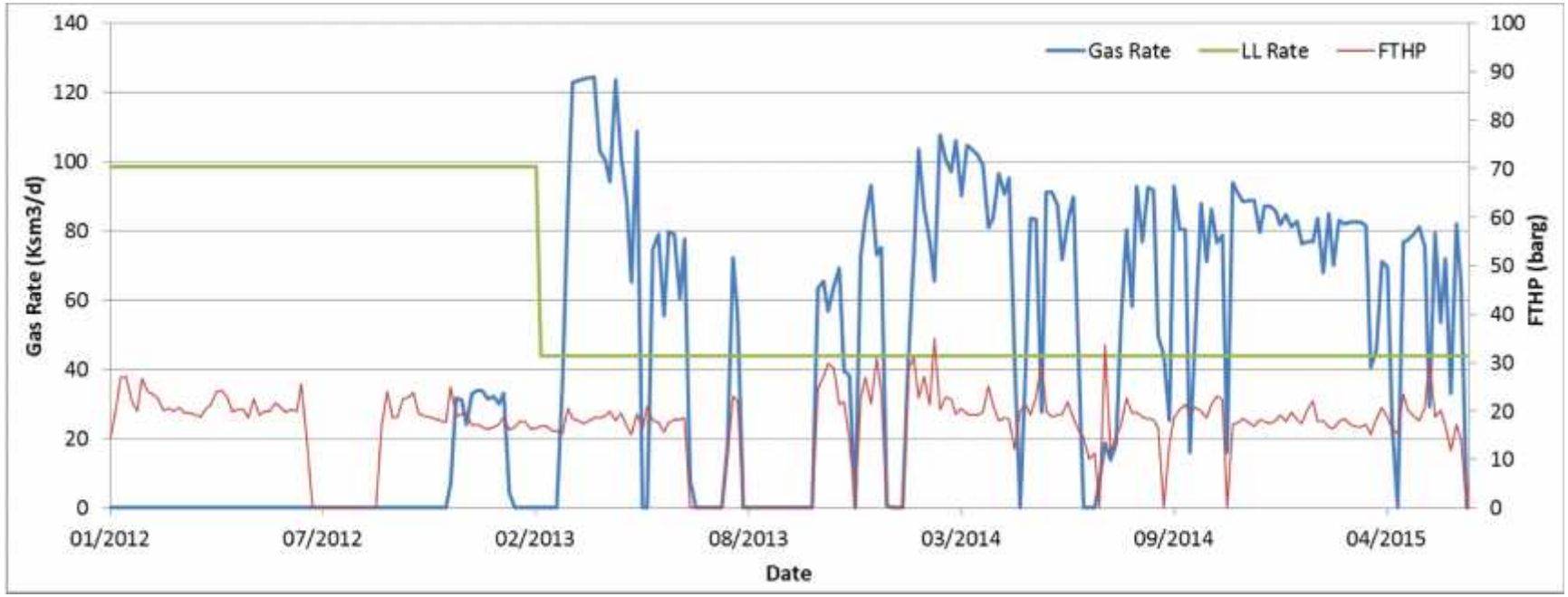
Since 2008, installed 17 coiled tubing velocity strings to date on 6 platforms.

Velocity strings are a proven GWD deliquification method, 'maintenance free' and well understood in modelling. Overall good results, however candidate selection is critical:

- *Sand: 3 x VS stopped producing due to HUD sand build up in liner (NL side).*
- *Mechanical: 1x VS hang off in TR-SSSV damaged the seal bore area and installation was cancelled (UK side)*
- *Failure: Accidental drop of VS with HWU (NL side)*
- *Timing: Two premature installations which constraint production (UK side)*



Case UK SNS: Velocity Strings (after ~3 yrs)

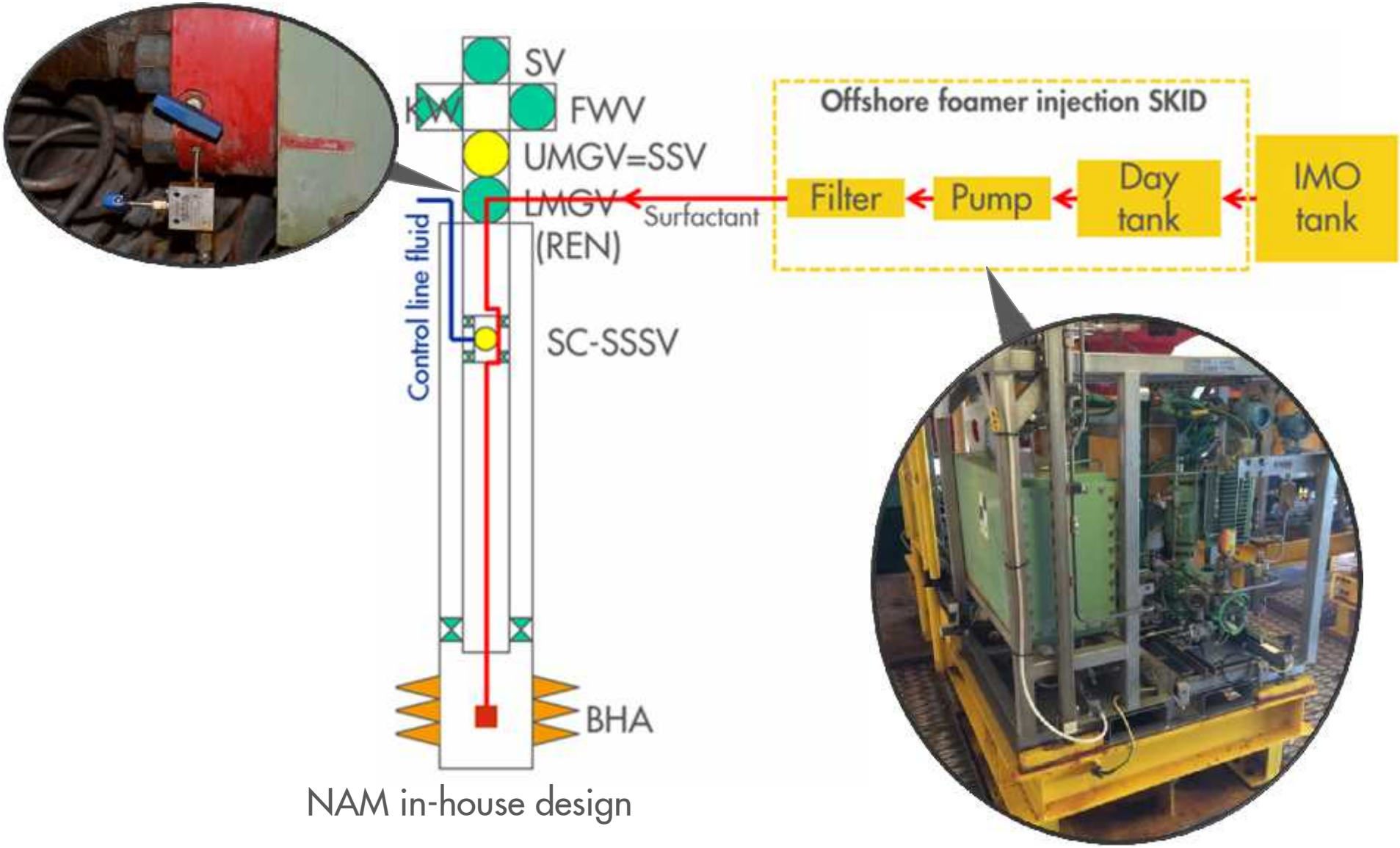


Well Details
- Pre VS Rate: 38 Ksm^3/d (intermittent)
- Initial VS Rate: 125 Ksm^3/d
- Current Pot: 70 Ksm^3/d @ FTHP: 18 barg
- CITHP: 84 barg
- WGR: 120 m^3/MMm^3
- A factor: 150 $bar^2/1000m^3/d$)

Completion Details
- No top string
- VS hanger at 340 m AHD in SSSV profile
- SSD @ 343 m AHD (ran closed)
- 2 7/8" CT @ 2440 m AHD – 40 deg incl
- 16Cr
- Installed in Jan 2013, Startup March 2013

Reducing LL and stabilizing production by velocity string

ONEgas Continuous Foam System (CF)



NAM in-house design

UK SNS CF foamer case study - Uptime

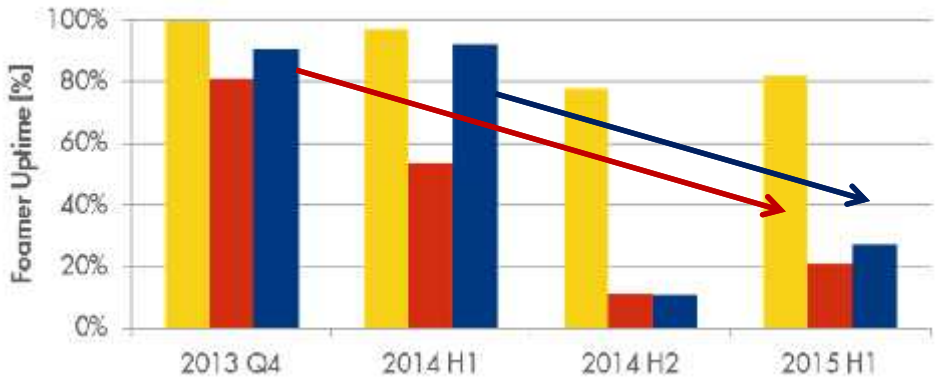
Case-study:
3 wells on a manned production facility

Drilled in 1990 and started liquid loading after 15-20 years of production

CF installed in 2013, successfully increased reserves recovery

Uptime decreased after 1 year, due to operational challenges

Foamer Uptime:

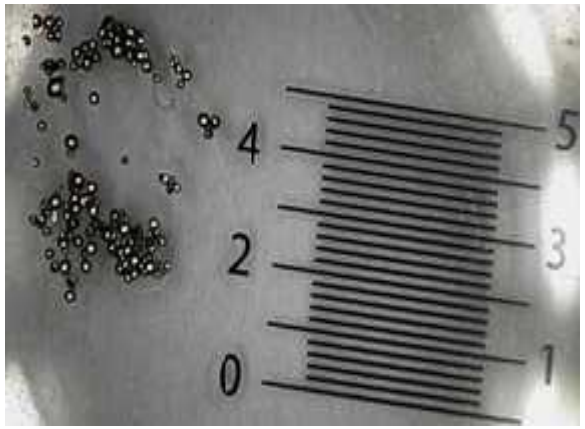


	Can produce intermittently:	Incremental capacity [MMscf/d]:	CF recovery vs total well recovery*:	Average foamer uptime*:
Well Y	Yes	4	5%	88%
Well R	No	2	2.5%	36%
Well B	No	2	10%	50%

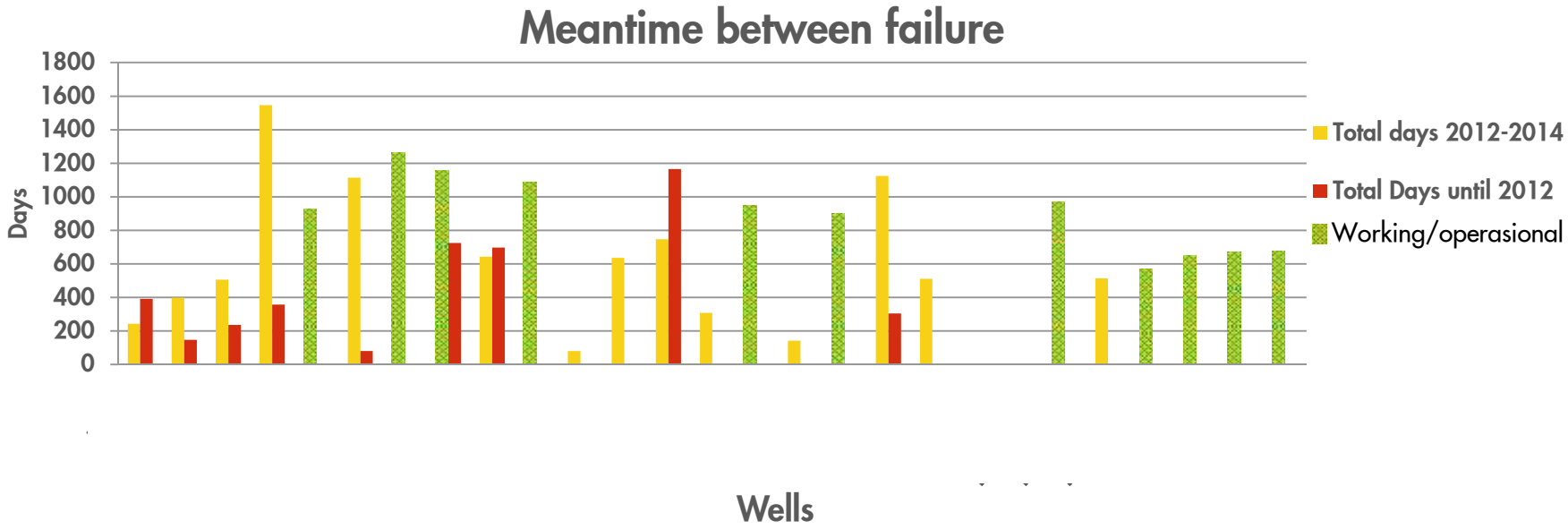
Continuous Foam failures

Issue:	Impact:	Mitigation:
Downhole Blockages	Stops foamer injection, reduces uptime, increases OPEX	Improve BHA, use downhole siphon, seamless capillary, sample foamer quality, filtering
Sand Erosion	Causes capillary string leaks and possible fish, increases OPEX	High grade materials, avoid high flow velocities, well selection
Poor Foam Separation	Need PRWI well, Causes separator trips	Anti-foamer, adopt bean-up strategy



Continuous Foam – Meantime between failure



Data:

- Average Meantime >2012 = 374 Days
- Average Meantime 2012-2014= 667 Days
- Design criteria = 2 years

Increase Meantime to Repair

1. Increase reliability components
2. Investigation failures
3. Update surfactant quality
4. Well selection

Challenges GWD

- *Though knowledge and screening tools are improving i.e Deliq factory, Prosper, SURPRISE, choosing the optimum well deliquification method is challenging.*
- *Deliquification methods are costly depending access location (and SSSV!). Average costs 1.5 – 2 mln Euro offshore. Emphasis on reducing costs.*
- *VS challenges: proven technology and 'keep it simple!' - best practice is to install VS below SSSV*
- *Foam challenges:*
  - *Foamer type compatibility issues (CI resistant)*
  - *Erosional velocities - sand*
  - *OIW > 30 ppm – PRWI injection wells dependent* - 500 – 2500 ppm,
  - *Operational Excellence and reliability - MTTR*
  - *CF Uptime*

Brown Field GWD in SNS/ONEgas

- Permanent deliquification methods are costly and not without risk. Only install GWD in wells which are actually LL! Timing is important.
- Optimum well inflow i.e. stimulation, clean out, soaks, WSO delayed GWD in various cases and pays off.
- IP and subsequent VS and/or foam is the preferred well GWD method in ONEgas off-shore. Foam installations on unmanned platform are on hold due to cost level.
- Based on inflow/out flow modeling, indicate foam applications to be the best option to enhance gas recovery from the various fields in SNS.
- Sand producers are risky candidates for GWD and require close controlled operation and/or downhole repair i.e. retrofit sand screens before any GWD.
- PRWI wells allow foam applications offshore. However, foam affect corrosion inhibitors and OIW content. PRWI dependency increasing offshore.