Report

Can reservoir depletion be credited for Relief Well Operations?

Petroleumstilsynet (PSA)

16 MARCH, 2022

add energy

Well Control & Blowout Support

Can reservoir depletion be credited for Relief Well Operations?

DATE:	REVISION / REFERENCE ID:	PAGES:
March 16, 2022	1	71

CLIENT:	Petroleumstilsynet (PSA)
CONTACT:	Roar Sognnes
DISTRIBUTION:	Ptil, Add Energy

ROLE:	NAME:	SIGNATURE:
Author	Morten Haug Emilsen	Morten Haug Emilsen
Author		
Reviewer	Geir Hedenstad	Geir Hedenstad
Approved	Ole B. Rygg	Ole B. Rygg

ABSTRACT:

Calculation of blowout and kill requirements in the event of an accidental blowout is a part of the environmental risk assessment performed in preparation for well activities done by the petroleum industry in Norway. The calculations are required by Petroleum Safety Authority (Ptil) and regulated through the Activities Regulations and the NORSOK standard.

This report relates to practical clarifications for the Activity Regulations § 86 on well control. Some operators do credit an expected reservoir depletion for some wells over a certain period in order to be able to carry out the kill operation using one (1) relief well in the event of a blowout. The study evaluates possible reservoir depletion during the time from a hypothetical blowout occurs until a relief well is ready for a dynamic kill operation and whether this can be credited in a Blowout Contingency Plan.

For more information about Add Energy, visit www.addenergy.no

KEY WORDS:

Well Control, Reservoir Depletion, Blowout Rates, Relief Well

Table of Contents

List of Tables

List of Figures

Summary

Calculation of blowout and kill requirements in the event of an accidental blowout is a part of the environmental risk assessment performed in preparation for well activities done by the petroleum industry in Norway. The calculations are required by the Petroleum Safety Authority (Ptil) and regulated through the Activities Regulations and the NORSOK standard.

The evaluations performed in this study relate to practical clarifications for the Activity Regulations §86 on well control. The intention of the regulation is to ensure that a worst-case blowout should be controlled by a single relief well. For some wells, it can however be challenging to be compliant using initial reservoir and fluid conditions.

There is no industry standard for how to model or credit depletion effects for blowout contingency planning. Some operators account for an expected reservoir depletion during a blowout to achieve a kill operation with one relief well. The approach is to define a fixed or variable blowout rate for an assumed duration of the blowout. Based on these two highly uncertain parameters, rate and time, a reduction in average reservoir pressure is estimated at the defined time of kill. This approach cannot be used for exploration wells or appraisal wells where the reservoir volume is unknown.

For development fields with better knowledge of the reservoir size, the potential depletion may be assessed. This calculation relies on the highly uncertain sequence of events following the initial incident. It is an understatement to say that predicting a rate over time during a blowout is a challenging exercise. Quite often, the blowout rate can escalate with time. For example, well barriers, the effect of these and other initial restrictions are subject to erosion and can be worn out. The Macondo blowout in the Gulf of Mexico in 2010 is one example with initial restrictions. For this incident, the reservoir pressure depleted 13 % after 87 days of flow. The downhole conditions can also change during a blowout. For example, on the Montara blowout in the Timor Sea in 2009, the initial gas rate was low, but at the time of intersection, the rate increased to the maximum flow potential.

If a blowout occurs, the primary goal is to contain and stop the flow as quickly as possible. In well design and contingency planning, a conservative approach is taken to enable handling of plausible and unplausible conditions and scenarios. The well barriers and surface equipment are dimensioned to withstand these loads and conditions. For example, the pressure rating of a capping stack used for a kill operation should handle the maximum initial shut-in pressure and a bullheading/kill margin. This should also apply when planning the last line of defense, a relief well kill operation. Having a contingency plan which relies on reservoir depletion departs significantly from this approach.

Some operators have internal guidelines specifying that reservoir depletion cannot be credited when planning a relief well kill operation. Based on experience from blowouts and their sequences of events, this is a wise decision. Data from actual blowouts do not support a methodology where depletion can be credited. A relief well kill operation should be capable of controlling the reservoir pressure at the time of the incident.

1. Background

1.1 General

This Chapter describes the scope of work and gives a brief background of a Relief Well Operation and why it is a vital part of blowout contingency plans and required by authorities, industry standards and operator's internal guidelines.

1.2 Scope of work

The scope of work relates to practical clarifications for the Activity Regulations §86 on well control. Some operators do credit an expected reservoir depletion for some wells over a certain period in order to be able to qualify the kill operation using one (1) relief well in the event of a blowout. The study evaluates possible reservoir depletion during the time from a hypothetical blowout occurs until a relief well is ready for a dynamic kill operation and whether it is reasonable to credit this in a Blowout Contingency Plan.

1.3 Blowout Contingency Planning

Today, Blowout Contingency Planning is an integral part of preparations for drilling operations. The primary purpose of a Blowout Contingency Plan is to minimize danger to life and protect the environment and valuable assets by minimizing response times and incorrect actions taken under stress. Questions like: "What if my primary barrier fails during our planned operation?" and "What if all barriers fail resulting in an uncontrolled blowout?" should be answered and mitigating options should be developed well in advance of the spud date. In an emergency, the more details that have been worked out in advance, the more efficient the response will be. In case of a blowout, there are generally two main strategies of regaining well control, surface intervention and relief well.

1.4 Surface intervention

Surface intervention operations aim to control the blowout by direct access to the wellhead or exit point of the blowing well. Surface intervention typically focuses on capping and variations of capping the well including bullheading, dynamic kill, pumping of viscous fluids / gunk plugs etc. [1].

The common requirement for surface intervention is safe access to the wellhead of the blowout well. Capping can be performed relatively quickly under the right circumstances. However, the disadvantages and limitations of this method are many. First, a rig must operate on top of or close to the exit point of the blowout which may be connected to high risk. For gas blowouts to surface or in shallow water, the explosive danger may be high. Secondly, when the uncontrolled flow is suddenly closed in and stopped at the wellhead, the pressure in the well will increase. This may result in an underground blowout, which in many cases can be more challenging to control compared to a surface or seabed blowout.

[1] "Capping of a well" refers to stopping an uncontrolled flow. The closing device, whether this is a new valve or other types of equipment is not essential. A Capping Stack on the other hand, is a dedicated piece of hardware designed to be installed on the wellhead of a blowing wellbore to control the flow.

1.5 What is a Relief Well?

A relief well provides a means to intercept and kill a blowout when surface intervention or capping requires an extended period or when that may not be possible. A relief well is the ultimate, and last line of defense, well control option in the event of a blowout. Today, a relief well is spudded shortly (within days[2]) after a blowout occurs and drilled towards a planned intersection depth (often below the last set casing shoe) of the blowout well. The blowout is then killed by pumping kill fluids down the relief well and into the blowout well. Relief well planning can be a critical safety measure, ensuring readiness and rapid response in the event of a catastrophic blowout that threatens assets, human life, and the environment.

1.6 History of Relief Wells

In 1933, a directional relief well was drilled on a prolific cratered blowout near Conroe in Texas and marked the first milestone in the evolution of relief well technology (ref. 10). In 1989, the first relief well drilled offshore with direct intersection into the blowout well (underground blowout) was completed by Saga Petroleum on the Ekofisk 2/4-14 blowout in the North Sea. The well was drilled with a direct intersection into the 8 ½" hole at a depth of nearly 5 km. No sidetracks were required, and nine electromagnetic ranging runs were made. This was a successful operation after two decades of refinement of the relief well technology including new hardware (ranging technology), new software (multiphase flow models) and new complex decision analysis.

1.7 What is the likelihood of a successful relief well operation?

The relief well kill strategy with direct intersection has been used successfully on many operations since the Ekofisk (well 2/4-14) operation in 1989. The concept has since been constantly developed including better surveying and directional control, passive magnetic and active electromagnetic ranging, steerable drilling systems, simulation models and subsea hardware equipment allowing higher injection rates of kill fluids (evaluated for the Ekofisk blowout). A relief well operation has a very high change of success. Demonstrating a feasible relief well kill operation should be a manageable task considering the experience gained from several actual kill operations and relief wells drilled regularly since 1989.

1.8 Why is it important to ensure the ability to kill a blowout using a relief well?

A relief well kill operation is applicable to all blowouts, including cratered blowouts and underground blowouts where surface intervention control methods have limited capabilities. It does not require access to the blowing wellbore, and it is often regarded as the safest and most reliable well control alternative. If a blowout cannot be killed by a relief well, there are no options left. Since relief well is the last line of defense, it is of utmost importance to demonstrate that a potential blowout can be brought under control by a relief well, an established and well-proven kill strategy. Especially, following the Macondo blowout in 2010, regulatory changes in the industry have focused on extensive relief well planning to make sure the industry to be better

[2] NORSOK D-10, Section 5.8.2: *"The time for mobilizing relief well rig(s) shall be evaluated in the planning phase. Initiation of relief well drilling should start no later than twelve (12) days after the decision to drill the relief well(s) has been taken".*

prepared in case of an emergency. Also, it serves to provide risk awareness throughout the planning and operational phases.

1.9 Increased focus and change in the regulations for Relief Well operations

In December 2015, the Activities Regulations was changed to ensure the ability to control a worst-case incident using a single relief well. The change was introduced based on experiences from the Deepwater Horizon accident in 2010 and the fact that no offshore wells have been killed by a dynamic kill operation involving more than one relief well.

1.10 What is the effect of the new regulation?

The increased focus on single relief well contingency can affect how wells are designed to comply. Unfortunately, this might also unveil some disadvantages for an operation. For drilling activities, the re-design (enforced by the regulation) can for example involve slimmer hole sizes and more casing strings. This will result in reduced kick tolerances, longer lasting operations, increased cost and ultimately not achieving the primary well objectives. In the effort of reducing the consequences of a hypothetical worst-case blowout scenario, one may in fact end up increasing the probability of an event. This can also be transferred to the testing and production phase and finally to the plug and abandonment phase (P&A) where the initial design can have advantages compared to the revised well design.

A well-known risk reduction principle is ALARP (As Low As Reasonable Practical). This also applies to well design where risk reducing measures are implemented if the risk-reduction effect is not significantly disproportionate to the cost of the implementation.

Another effect of the new regulation is refinements on the data basis done to reduce the flow potential and kill requirements for a well until it complies with single relief well contingency. This can also involve taking credit for possible depletion of the reservoir.

2. Mechanism of Reservoir Depletion

2.1 General

This Chapter gives and overview typical factors and mechanisms that can affect the risk and uncertainty in calculations of possible reservoir depletion during a blowout.

2.2 Hydrocarbon reservoir

A hydrocarbon reservoir contains volumes of gas, oil and water stored in porous and permeable rock formations. The pore pressure at discovery prior to any production can be called initial reservoir pressure, alternatively virgin reservoir pressure.

2.3 Reservoir depletion

When formation fluids are produced from the reservoir, the average reservoir pressure will normally decline. This decline is called depletion.

There are several mechanisms that drives reservoir depletion:

- Reservoir volume
- Production (blowout) rate
- Hydrocarbon fluid composition
- Natural pressure support from surrounding or underlying aquifers

2.3.1 Reservoir volume

The most important parameter in depletion calculations is the size of the reservoir. It is very difficult to predict this for exploration wells and appraisal wells. Some wells are dry (i.e., no signs of hydrocarbon bearing formations) whilst others can expose huge discoveries.

For reference, the largest gas reservoir in the world is the South Pars field in Iran and Qatar (ref. 7). This gas field is estimated to contain 35 000 GSm^3 of gas. This is 100 times larger than the Ormen Lange field in the North Sea which was estimated to contain 346.6 GSm^3 of gas (before production). Table 2.1 shows a list of the world's largest gas fields.

Table 2.1: World's largest gas fields

No	Gas field	Country	Gas in place [GSm³]
1	South Pars	Iran and Qatar	35 000
2	Urengoy	Russia	6 300
3	Yamburg	Russia	3 900
4	Hassi R'Mel	Algeria	3 500
5	Shtokman	Russia	3 100
6	Galkynysh	Turkmenistan	2 800
7	Zapolyarnoye	Russia	2 700
8	Hugoton	USA	2 300
9	Groningen	Netherlands	2 100
10	Bovanenkovo	Russia	2 000
11	Medvezhye	Russia	1 900
12	Troll	Norway	1 440
13	Dauletabad	Turkmenistan	1 400
14	Karachaganak	Kazakhstan	1 370
15	North Pars	Iran	1 340
16	Kish	Iran	1 300
17	Orenburg	Russia	1 300
18	Kharasavey	Russia	1 200
19	Shah Deniz	Azerbaijan	1 200
20	Golshan	Iran	850
21	Zohr[2]	Egypt	850
22	Tabnak	Iran	620
23	Kangan	Iran	570

2.3.2 Production (blowout) rate

Next after the reservoir size, the production (blowout rate) is important for depletion calculations. Applying the worst-case blowout rate for depletion calculations from day 1 will for most cases be a wrong assumption. It is not uncommon that surface intervention teams have been working for weeks with different unsuccessful kill attempts which affects the flow rate before the final control has been achieved. This was the case for the Macondo blowout in 2010 where initial blowout rate was restricted by the drillpipe located inside the BOP, which eroded over time and resulted in higher blowout rate. Similar observation was done during the Montara blowout in 2009 where the blowout rate of gas increased during the kill operation. No sign of depletion was observed after 74 days of flow.

2.3.3 Hydrocarbon fluid composition

The hydrocarbon fluid composition is a driver for depletion. Gas reservoirs deplete slower than oil reservoirs due to the higher compressibility. For an oil reservoir, once the pressure falls below the bubble point pressure, gas flashing out of solution will help maintaining the pressure. Hence a good representation of the reservoir fluid is important for depletion calculations.

2.3.4 Natural pressure support from underlying aquifers

Some reservoirs are in communication with aquifers (formations filled with water). When pressure decreases with production, the compressed water in the aquifer will expand into the reservoir and reduce the rate of depletion. The degree to which water influx affects the pressure depends on the size of the aquifer, the degree of communication between the aquifer and hydrocarbon reservoir, and ultimately how much water that will flow into the hydrocarbon reservoir.

2.4 Assumptions and uncertainty in calculations of depletion

Question: By introducing depletion modelling into the relief well kill calculations, could it lead to a source of errors and inaccuracy?

Answer: Yes

The industry practice is to use the most likely (P50) values for reservoir data when calculating blowout potentials. Including reservoir depletion modelling into the analysis, additional uncertainty and potential sources of errors will be introduced. This includes uncertainty in data used for the depletion modelling (i.e., the size of the reservoir), but as important, assumptions will have to be made regarding the sequence of events occurring from the initial well control incident until the relief well is ready for intersection.

This can be illustrated with the following example. A well control situation occurs for a well with very high flow potential, but with an initial low rate due to a partly working BOP barrier element. The relief well is spudded according to procedures and being drilled in parallel with the ongoing surface intervention activities. Suddenly, the gas alarm goes off on the rig performing surface intervention and an Emergency Disconnect Sequence (EDS) is initiated. The BOP's shear ram is activated but bubbles are still observed at surface. ROVs are mobilized trying to work on the BOP, but without success. Several weeks later, before the relief well is ready to intersect, the BOP is eroded, and the flow rate increases dramatically and reaches the full flow potential from the reservoir.

The well control sequence illustrated in the example above is not uncommon. For this case, the depletion was zero. For developed fields with known reservoir properties where depletion *can* be calculated (in contrast to exploration wells), the assumption will still have to be made with respect to the sequence of events including flow rate and duration. Strictly speaking, this assumption is impossible to foresee and experience from actual blowouts supports that predicting reservoir depletion is not possible. In any case, it is highly unlikely that this would be modelled correctly in a relief well contingency plan developed to demonstrate that it is possible to recover from the worst-case situation.

2.5 Can fracture pressure be affected by reservoir depletion?

The answer to the question in the heading of this section is yes. If depletion is expected and a new pore pressure is estimated, the effect on the fracture pressure should also be accounted for. Typically, a reduction in pore pressure will result in a reduction in the fracture pressure. The dependency varies with the formation type and is high for chalk and sandstones and somewhat less for shales. A reduction in fracture pressure will have an impact on the on the kill mud that can be used for the dynamic kill operation and this should be accounted for.

3. Governing standards, regulations and guidelines

3.1 General

Regulations regarding preparedness and contingency planning in case of a blowout vary across the globe. The main standards referenced globally are from Norway, USA, Canada, Australia, New Zealand and the UK. Even if there are variations between the legislations, the industry (both regulators and operators) will benefit from a harmonized and consistent approach towards the blowout contingency planning (BCP) for operations internationally. This Chapter references some of the governing regulations for the mentioned locations. Even if the scope of work for this study relates to Norwegian water, it will be worth-while throwing a glance of what other regulators are requiring.

In addition to governmental regulations, some industry standards and some operator's internal guidelines are referenced.

3.2 Regulations

3.2.1 Norway, Activities Regulations

The Activity Regulations relates to conducting petroleum activities in Norwegian Waters. In Chapter XV and § 86 "Well control", the following is presented:

In the event of a well control incident, it shall be possible to regain well control by intervening directly in or on the well or by drilling one (1) relief well. This applies to wells where planning of drilling activities has been decided on after 1 January 2016.

In special cases, drilling activities that require more than one (1) relief well to regain well control in the event of a well control incident, can be planned for. When planning such activities, the solutions for regaining well control shall be verified by a party of organisational independence, no later than three months before planned start-up.

Where capping can be a measure in a well control incident, the operator shall have access to capping equipment for subsea wells.

Plans that describe how to regain the well control, shall be prepared.

Furthermore, the Guideline to this paragraph provides the following info:

Well control incident as mentioned in the first subsection, means the failure of one or more well barriers where the failure results in unintended flow of formation fluid into the well, cross flow in the well or outflow to the external environment.

Intervening directly in or on the well as mentioned in the first subsection, means re-establishment of barriers by using established well control methods or by using capping equipment.

In the event of using established well control methods, the NORSOK D-010 standard, Chapter 5.2.8 should be used.

In the event of using capping equipment for subsea wells, the NORSOK D-010 standard, Chapter 5.8.3 should be used.

In order to regain well control by relief well drilling as mentioned in the first subsection, the NORSOK D-010 standard, Chapter 5.8.2 should be used.

When planning activities as mentioned in the second subsection, the NORSOK D-010 standard, Chapter 5.8 should be used, with the following addition: evaluation of technical and operational feasibility, plus location, operation and well specific risk assessments for the method chosen.

Organisational independence as mentioned in the second subsection, is described in the guidelines to Section 19 of the Framework Regulations.

To fulfil the requirement to plans as mentioned in the fourth subsection, the NORSOK D-010 standard, Chapters 5.8 should be used, with the following additions:

a. the plans should describe the need for and availability of facility(ies) and services,
b. plans for relief well drilling and capping operations that require modifications of facility(ies), use of additional equipment, vessels or new technology, should detail how this can be mobilised and operative prior to start-up of the operation that requires this.

3.2.2 Norway, Facilities Regulations

In the Facilities Regulations §5, the same wording as mentioned in the Activities Regulations §86 is repeated:

"Wells shall be designed so that well control can be regained by means of one (1) relief well. In special cases, wells can be designed for more than one (1) relief well."

3.2.3 USA

The United States Bureau of Safety and Environmental Enforcement (BSEE) requires all operators to provide documentation demonstrating their capacity to drill a relief well. Operators in the Gulf of Mexico must submit the surface location for a relief well along with their application for a permit to drill. Two locations are generally identified, and relief well paths are planned for each at every casing point prior to an interval where hydrocarbons may be encountered. A scenario for the potential blowout of the proposed well expected will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum duration of the potential blowout. Also, discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Estimate the time it would take to drill a relief well.

3.2.4 Canada

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) has guidelines respecting Contingency Plans:

The operator is expected to have a contingency plan for the identification and sourcing of an alternate drilling installation(s) that is capable of drilling a relief well. The plan should provide a description of the installation's required operating capability, ancillary equipment, availability, and the schedule for mobilization to the wellsite. The source of supply for a backup wellhead system and all consumables required to set conductor and surface casing for the relief well should also be identified.

C-NLOPB also reference the NORSOK standard and expect operators to follow section 5.8 in NORSOK D-010.

The National Energy Board (NEB) reviewed the offshore drilling safety and environmental requirements for Canada's Arctic ("The Arctic Review") soon after the Deepwater Horizon incident. The Board reaffirmed its policy that says any applicant requesting authorization to drill must demonstrate, in its contingency plan, the capability to drill a relief well to kill an out-of-control well during the same drilling season. The flowing applies to demonstrate Same Season Relief Well (SSRW) capability:

a) *Identification of the drilling unit that will be used, including mobilization details;*
b) *Identification of a minimum of two suitable locations for drilling a same season relief well, including shallow seismic interpretation of the top-hole section;*
c) *A hazard assessment for positioning the relief well close to the out-of-control well;*
d) *Confirmation that the relief well drilling unit, support craft, and supplies are available and can drill the relief well and kill the out-of-control well in the same drilling season; and*
e) *Confirmation of the availability of well equipment and specialized equipment, personnel, services, and consumables to kill the out-of-control well during the same drilling season. (National Energy Board 2015)*

3.2.5 United Kingdom

After the Deepwater Horizon incident in the Gulf of Mexico, all operators on the UK continental shelf were reminded of their requirement to have an oil pollution emergency plan (OPEP) in place as per the Merchant Shipping (Oil Pollution Preparedness, Response and Cooperation Convention) Regulations 1998 (DECC 2015b). In a Letter to Industry, the Department of Energy & Climate Change (DECC) emphasized the requirement for adequate planning in case of a worst-case scenario where all containment barriers have failed resulting in a blow-out, that would normally require the drilling of a relief well (DECC 2010).

Guidance notes were provided by the DECC to support operators in their OPEP duties:

- Guidance Notes for Preparing For Offshore Oil & Gas Installations and Relevant Oil Handling Facilities (DECC 2012)

- Guidance Notes for Preparing Oil Pollution Emergency Plans For Offshore Oil & Gas Installations and Relevant Oil Handling Facilities (DECC 2015a)

Oil & Gas UK released Guidelines on Relief Well Planning for Offshore Wells in 2012 and a revised edition in 2013. The guidance notes for Relief Well Plan (RWP) call for a complexity assessment to determine the detail involved in the RWP (e.g., a complex RWP requires well kill modeling, kill fluid, kill design and required pumping equipment, storage volume and mixing capability), whereas a basic RWP does not.

3.2.6 European Union

In June 2013, the European Union (EU) Parliament introduced a new Directive (2013/30/EU) with the intention of creating the frame to standardize some of the requirements in terms of contingency planning for the oil and gas industry all across the EU area and, to some extent, outside the EU area as well. As part of the Directive considerations, the following comprise some of the most important instructions:

a) in respect of installations, to give independent assurance that the safety and environmental critical elements identified in the risk assessment for the installation, as described in the report on major hazards, are suitable and that the schedule of examination and testing of the safety and environmental critical elements is suitable, up-to-date and operating as intended;
b) in respect of notifications of well operations, to give independent assurance that the well design and well control measures are suitable for the anticipated well conditions at all times.

5. Member States shall ensure that operators and owners respond to and take appropriate action based on the advice of the independent verifier.
6. Member States shall require operators and owners to ensure that advice received from the independent verifier pursuant to point (a) of paragraph 4 and records of action taken on the basis of such advice are made available to the competent authority and retained by the operator or the owner for a period of six months after completion of the offshore oil and gas operations to which they relate.

3.2.7 Australia

The document "Source control planning and procedures" describes NOPSEMA's expectations with regards to source control planning content of the Environmental Plan (EP), Well Operating Management Plan (WOMP) and the Source Control Emergency Response Plan (SCERP), and describes the regulatory assessment focus of the EP and WOMP and the compliance monitoring inspection process and focus of the SCERP.

Section 3.2.5 "Relief Well Locations, Design, and Dynamic Kill Plan" and section 4.1.8 "Relief Well locations, design, and Dynamic Kill Plan " defines the requirements within the WOMP and SCERP respectively.

The requirements in 3.2.5 yields:

Provide a summary of the blowout contingency plan, including:

- *modelling assumptions and scenarios*
- *primary kill strategy*
- *2x relief well locations (or possible relief well quadrant)*
- *relief well design*
- *proposed relief well trajectory and intersect drawings*
- *relief well rig mud pumps specifications and ancillary equipment requirements to perform dynamic kill*

Context
Identify and nominate at least two possible relief well locations, or a possible relief well quadrant at a safe distance from the well (blowout) that considers seabed and sub-bottom/shallow hazards, and seasonal dominant wind conditions and currents to avoid volatile gases and accumulations of oil on the surface.

Plan and define relief well trajectories considering proximity ranging tools, approach and intersect method. Perform Dynamic Kill analysis to determine volumes, density, and pump rates for well kill fluids. Define pump and ancillary equipment needs for well kill including redundancy during critical well kill operations. The description should define the number of relief wells required to kill the blowout well, identification of possible relief well locations, shallow gas assessment, well paths, and equipment logistics and specialist service provider arrangements.

Provide casing and wellhead design for relief wells and provide drawings of the relief well(s).

Regulatory assessment
Assess relief well locations, design, Dynamic Kill analysis, and relief well drilling rig specification requirements to ensure fit-for-purpose.

The document does not indicate anything with respect to possible reservoir depletion.

3.2.8 New Zealand

The Well Control Contingency Plan should identify potential well control failure scenarios (e.g., BOP failure, rig fire, loss of well bore integrity) and the associated probabilities of these occurring. The plan should also outline the implications of each scenario on the potential response options. Operators should not eliminate loss of well control scenarios from further consideration simply because they consider there is a very low likelihood of them occurring. For example, when identifying blowout scenarios, the fact that a range of control measures may be put in place to minimize the risk of a blowout does not mean that this scenario no longer requires further preparedness and response controls that may contribute to minimizing the consequence of the event.

Reservoir characteristics is mentioned. The operator should identify well and reservoir information including information outlining the nature of the hydrocarbons (crude/gas/condensate and contaminants including maximum concentrations); the well flow characteristics; and the maximum shut-in wellhead pressure. If there are reservoir characteristics relevant to this information, such as High Pressure and High Temperature (HP/HT) conditions, this information should also be included.

For exploration wells analogues could be used to demonstrate an understanding of potential reservoir content. Where there is uncertainty surrounding reservoir characteristics, operators should describe the possible range anticipated for each characteristic and confirm these details where relevant as they become available after commencing drilling.

The selected flow rate should be used to calculate the predicted total loss of hydrocarbons during the period covered by the modelling, and during the estimated time taken to stop the release, and the calculated volumes should be clearly stated.

3.3 Standards and guidelines

3.3.1 NORSOK D-010

The NORSOK standard was a result of a collaborative initiative started in 1993 between the authorities and the petroleum industry. The standard is developed to provide good technical and cost-effective solutions to ensure that the petroleum resources are exploited and managed in the best possible way by the industry and the authorities.

NORSOK D-010 focuses on well integrity in drilling and well operations. In section 5.8.1 "Blowout Contingency Plan", the standard specifies that "A blowout simulation study shall be performed for the well design expected to give the highest blowout rates. A corresponding kill rate simulation shall be performed for a relief well targeting the casing shoe above the blowing reservoir".

The standard also lists the possible flow path scenarios that should be covered, including the open hole scenario. For prolific gas reservoirs, the "open hole" blowout scenario (without drillpipe in the hole) is typically causing the highest kill requirements.

Furthermore, the standard indicate that the expected values should be used for calculations. It also emphasizes that no restrictions should be credited in the flow path.

An important statement is listed at the end of section 5.8.1:

"For offshore wells, the well design should enable killing a blowout with one (1) relief well. If two (2) relief wells are required, it shall be documented that such an activity is feasible with respect to logistics, weather criteria and availability of rigs. The feasibility should be supported by a risk assessment demonstrating that the proposed solution involving more than one relief well is achievable. An offshore well design that requires more than two (2) relief wells is not acceptable".

The standard highlights that a given well trajectory shall facilitate intersection with a relief well in the case of a blowout (section 6.7.4). It specifies that well control action plans shall include the possibilities of relief well drilling.

3.3.2 NOROG Guideline for calculating blowout rates

The "Guidance on calculating blowout rates and duration for use in environmental risk analyses", developed by NOROG, has been a great help for the industry, mainly in Norway, but also for other parts of the world, since the first version was published in 2004.

In Section 2.6.1 "Reservoir pressure" of the Supplementary report "Data Basis For Blowout Rate Simulations", depletion is mentioned:

The reservoir pressure should be specified as a gradient or an absolute pressure at a given depth. Pressure distribution within the reservoir zone is determined by the hydrostatic head created by the reservoir fluid.

Reservoir pressure can vary with time and might deplete during the time frame of a blowout. If that is the case, an averaged blowout rate can be estimated for spill volume calculations. Where relief well kill operations are concerned, the depleted reservoir pressure can be used for the kill simulations at the estimated time of intervention. Since the rate of depletion depends on a number of mechanisms with a high degree of uncertainty, however, the initial reservoir pressure should still be taken into account in kill simulations and contingency planning.

3.3.3 SPE Technical Report on WCD

The US Bureau of Ocean Energy Management (BOEM) defines worst-case discharge (WCD) as the single highest daily flow rate of liquid hydrocarbon during an uncontrolled wellbore flow event—that is, the average daily flow rate on the day that the highest rate occurs, under worst-case conditions (a blowout). It is neither the total volume spilled over the duration of the event, nor the maximum possible flow rate that would result from high-side reservoir parameters, nor a distribution of outcomes. It is a single value for the expected flow rate calculated under worst-case wellbore conditions using known (expected) reservoir properties.

The technical report "Calculation of Worst-Case Discharge (WCD)" states the following:

"Reservoir Pressure. Assess the current reservoir pressure based on analog data, historical performance, and offset data. Exploration wells may be assessed using analog and/or regional pressure gradients. New reservoirs should be assessed at initial reservoir pressure. For fields with historical production, estimates of depletion and repressurization should be addressed and documented".

3.3.4 Australian Offshore Titleholders Source Control Guideline

This guideline extensively references existing industry standards. It adopts the source control framework described in the International Association of Oil & Gas Producers (IOGP) Source Control Emergency Response Planning Guide for Subsea Wells, Report 594, January 2019, supplemented by other industry documents as necessary. Relief well drilling, not addressed in IOGP 594, adopts Oil & Gas UK (OGUK)

Guidelines on Relief Well Planning for Offshore Wells (OP064), Issue 2, March 2013. Other technical references are described within the guideline at appropriate places. The intention has been to use the various references in a consistent manner to the Australian region and Australian regulatory framework. This guideline has also been written to address matters described in NOPSEMA Information Paper: Source Control Planning and Procedures.

The "Worst-case Discharge" is defined in Section 8.1:
Worst-case discharge (WCD) is defined as the single highest daily flow rate of hydrocarbons during an uncontrolled wellbore flow event. That is, the average daily flow rate on the day that the highest rate occurs, under worst-case conditions (a blowout). It is neither the total volume spilled over the duration of the event, nor the maximum possible flow rate that would result from high-side reservoir parameters, nor a distribution of outcomes. It is a single value for the expected flow rate calculated under worst-case wellbore conditions using known (expected) reservoir properties.

Furthermore, during kill operation, the following applies:

Calculated rates at the expected time of capping or relief well kill operations should be used to determine feasibility of capping and well kill activities. For example, if the capping stack is expected to be deployed 21 days after the start of the uncontrolled wellbore flow event, the calculated discharge rate on day 21 should be used for plume analyses and landing feasibility. If the relief well is drilled and kill operations are expected to start 70 days after the start of the uncontrolled wellbore flow event, the calculated discharge rate on day 70 should be used for dynamic kill modelling.

In section 13.4, "Dynamic Well Kill" is defined and it's worth mentioning the wording about using high kill mud weights as a means to reduce the kill rate:

The selection of kill mud density should be based upon the fracture gradient of the open hole between the intersect point and the last string of casing or liner run in the relief well. During the dynamic kill, bottom hole pressures will be very low so mud density exceeding fracture gradient during this phase is not a concern. However, once the well is killed, the static bottom hole pressure of the kill mud should not exceed the fracture pressure of the open hole section. It is possible to alter the kill mud density during the dynamic kill by initially pumping a kill mud weight greater than the fracture gradient of the open hole and then reducing the mud weight as the well kill is completed. This however adds complexity and should only be planned after detailed analysis.

Also, section 13.4 "Dynamic Well Kill", discuss the modelling input and reservoir depletion is mentioned in the list of parameters required to model the inflow from the reservoir:

- Effective horizontal permeability
- Net pay
- Skin
- Pore pressure
- Reservoir depletion (if applicable at the time the well is penetrated)

In section 13.5 "Complex Well Kill Options", high rate operations are specifically mentioned. In Australia, highly permeable, highly prolific gas wells are not uncommon. The dynamic kill for a blowout in such a well can be very challenging and this section includes some options to facilitate a successful kill operation including redesign of well, redesign of relief well and use more relief wells. The guideline enhances:

Twin relief wells are the least preferred option because of the practical complexity associated with the ranging, intersection and kill operation from two MODUs simultaneously. These limitations mean that some titleholders do not accept the option of two relief wells, and unless an alternate single relief well dynamic kill strategy is shown to be satisfactory, the primary well architecture would have to be changed to reduce the blowout potential (primary well casing ID reduced to lower the WCD rate, see Section 8.2)

The guideline also lists the Relief Well Injection Spool (RWIS) as being a less complex solution compared to a dual relief well kill operation:

One of the greatest constraints in the hydraulic model is pumping kill mud at high rate down the relief well MODU's choke and kill lines and into the relief well drillpipe x casing annulus below closed BOP pipe rams. This configuration allows the bottom hole pressure to be monitored on the shut-in drillpipe during the kill operation. The choke and kill lines are typically 3" – 4" ID and create significant dynamic backpressure during the pumping operation.

Technology has been developed to run an injection spool latched on to the wellhead of a relief well and then the relief well MODU's BOP latched on top of the spool. The additional spool has side outlets which can be tied into additional pumping capacity on a separate vessel, via flexible flowlines. This allows the well kill to be executed using the pumping capacity on both the relief well MODU (pumping down its choke and kill lines) at the same time as the second vessel is pumping into the annulus via the flexible flowlines and RWIS. This allows a greater kill capacity and may simplify the overall operation (in comparison to two relief wells).

Conceptually, the technology appears simple, but the additional operational complexity, whilst less than a second relief well, should not be underestimated. The RWIS with second pumping vessel should only be considered if deemed necessary. To date, this technology has not actually been used and unforeseen challenges are likely in any first implementation. If considered, a full engineering, logistical and operational plan should be developed and documented, including sea floor layouts and surface access routes.

3.4 Operator's internal guidelines and consortiums

The industry benefits from having approximately the same standard in relation to safety work and emergency preparedness. Even though there are some differences in the regulatory regime in different places of the world, the major operating companies have similar internal requirements and guidelines when it comes to safety and risk assessments for well control. This is also emphasized through their collaboration in various oil spill response consortiums like Oil Spill Response Limited (OSRL), HWCG LLC, MWCC, OSPRAG and WellCONTAINED. These are typical consortiums with access to capping stacks as one important tool in the toolbox for contingency. In several countries (e.g., Norway and in the U.S. Gulf of Mexico (GOM)), it is mandatory for Operators conducting subsea drilling operations to demonstrate access to a subsea capping stack and the necessary expertise and ability to mobilize and install the stack offshore.

To highlight similarities and (to some extent differences) between the operators, some examples from their internal well control guidelines are provided below. The focus has been on single relief well contingency and application of depletion if existing:

3.4.1 Company A (a major international operator)

"All intervals are at initial reservoir pressure conditions, unless an infill development well in which the reservoir (depletion or injection) conditions are known".

3.4.2 Company B (a major international operator)

"A Worst-Case Discharge (WCD) and kill rate simulation study SHALL[WELLS] be performed by using expectation case for the pore pressures used in the casing design of the target well:

- *In case of a scenario in which well integrity (WI) loss occurs from a small nondepleted reservoir [less than 35 Bcf (1 Bcm)] and it is necessary to resolve the WI loss by a relief well, the local well engineering team shall not take reservoir depletion into account for WCD modeling.*
- *In case of an existing well, the most recent known reservoir conditions shall be used to estimate the kill requirements".*

3.4.3 Company C (Norwegian oil and gas operator)

"It is acceptable to use transient productivity index in blowout and kill simulation, i.e. reduced near wellbore reservoir pressure as a function of time from start of blowout to the time of kill operation. The time for drilling the relief well should be assessed based on the planned relief well design. The transient productivity index calculations must be quality controlled by relevant internal personnel".

3.4.4 Company D (Australian oil and gas operator)

"If pressure and flow requirements exceed the limits of a basic well kill, set out in Section 6 Perform Well Kill Modelling, a formal peer reviewed risk assessment must be performed, documenting the feasibility of an alternate well kill method (see Section 6.1 Complex Relief Well Kill for alternative methods)".

"For planning purposes, Company does not consider Plans that require two rigs to drill two relief wells and perform simultaneous kills to be a viable solution".

4. Blowout Statistics and SOBD

4.1 General

The SINTEF Offshore Blowout Database (SOBD) was initiated in 1984 and is a comprehensive event database for blowout risk assessment. The database includes information on 702 (November 2021 number) offshore blowouts/well releases that have occurred world-wide since 1955 and overall exposure data from the US Gulf of Mexico, Outer Continental Shelf and the North Sea. Blowouts in UK, Netherlands, Canada, US Pacific OCS, Australia and Denmark are also covered in the database.

From 1 January 1980 through 31 December 2019, a total of 313 blowouts/well releases from the US GoM OCS and the North Sea were consolidated in the database. Table 4.1 shows an overview of blowouts occurrence by operational phase. According to the table, 73 blowouts and well releases occurred during drilling in this period.

Table 4.1: Number of blowouts experienced during different operational phases.

AREA	Dev. drig	Unk. drig	Comp-letion	Work-over	Production		Wire-line	Abandoned well		Unknown/other	Total
					External cause*	No ext. cause*		Ext. cause*	No ext. cause*		
US GoM OCS	58	1	14	46	11	17	6		3	1	217
	26,7%	0,5%	6,5%	21,2%	5,1%	7,8%	2,8%		1,4%	0,5%	100,0%
Norwegian & UK waters	12	2	7	17	1	8	10		2		94
	12,8%	2,1%	7,4%	18,1%	1,1%	8,5%	10,6%		2,1%		100,0%
Total	70	3	21	63	12	25	16	0	5	1	311
	22,5%	1,0%	6,8%	20,3%	3,9%	8,0%	5,1%	0,0%	1,6%	0,3%	100,0%

4.2 Database structure

The blowouts and well releases are categorized based on several parameters, emphasizing blowout causes. It includes blowout/well release descriptions, drilling and production exposure data for certain areas in the world and contains 51 different fields describing each blowout/well release. The various fields are grouped in six different groups. They are:

1. Category and location
2. Well description
3. Present operation
4. Blowout causes
5. Blowout Characteristics
6. Other

The main group 5, "Blowout Characteristics" is divided into:

- Flow path
- Flow medium
- Flowrate (low quality)
- Release point
- Ignition time
- Ignition type
- Consequence class
- Material loss
- Pollution
- Lost production (low quality)
- Fatalities
- Duration

The alternatives listed in the Flow path category are divided into:

A. Through drill string/tubing
B. Through annulus
C. Through outer annulus
D. Outside casing
E. Underground blowout

The worst-case blowouts driving the kill requirements are often related to the open hole flow scenario. It is therefore worth mentioning that there is no category for "Open Hole" blowouts where the drillpipe was out of the hole in the database. These blowouts are typically categorized as "B. Through annulus".

There is no category in the database telling whether the blowout was fully open or restricted by any means. Hence, no information is directly available from the SOBD that can be used as a measure for evaluating the probability for restricted blowouts.

The main group 6 "Other", include five fields:
- control method
- remarks (includes a description of the incident)
- data quality (includes an evaluation of the source data quality)
- last revision date and
- references

For some of the incidents, the control method can be referred to as "depleted". However, this indicates that the blowout did stop by itself without any other active control methods, and are therefore not applicable to the assessment being done in this study.

The control method "Relief Well" only contains two incidents; the Montara blowout in the Timor Sea in 2009 and the Main Pass, Block 91, Platform A (MP 91A) blowout in the Gulf of Mexico in 2007.

4.3 Definition of Blowout and Well Release

The definition of a Blowout is taken from the NPD's proposal for new regulations in 2000, ("Aktivitetsforskriften, eksternt høringsutkast av 3.7.2000, høringsfrist 3.11.2000"):

"A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed."

(The definition has not become a part of the Petroleum Safety Authority Norway regulation, but remains the database blowout definition).

The definition of a well release is a release of oil or gas flowed from the well from some point were flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.

4.4 Data applicable for operations in the NCS

The Database includes a field named "North Sea Standard" that identifies blowouts and well releases that likely could occur in North Sea operations for the reason that the procedures or equipment utilized when the incident occurred are similar to North Sea equipment or procedures. Further, only blowouts that occurred after January 1980 have been focused on in which the quality of the data is good.

When including all blowouts and well releases occurring after 1980, approximately 50 % are categorized as blowouts and the remaining 50 % well releases. For worst-case blowouts requiring a relief well, the well releases are of no interest, and hence the number of applicable cases is reduced.

Focusing on drilling blowouts will reduce the number of applicable scenarios even more. According to ref./5/, between 2000 and 2015, there were 20 blowouts with seabed/surface release during exploration and development drilling. Out of these, 12 of the incidents occurred when drilling with a jack-up rig, 4 with a semi-submersible, 1 with a drillship and 3 with a jacket.

4.5 Worst-case flow path

The blowouts found applicable for the NCS are categorized into operations, and further into flow paths. Figure 4.1 shows a break-down of the incidents being applicable for drilling operations in the NCS between 1980 and 2014.

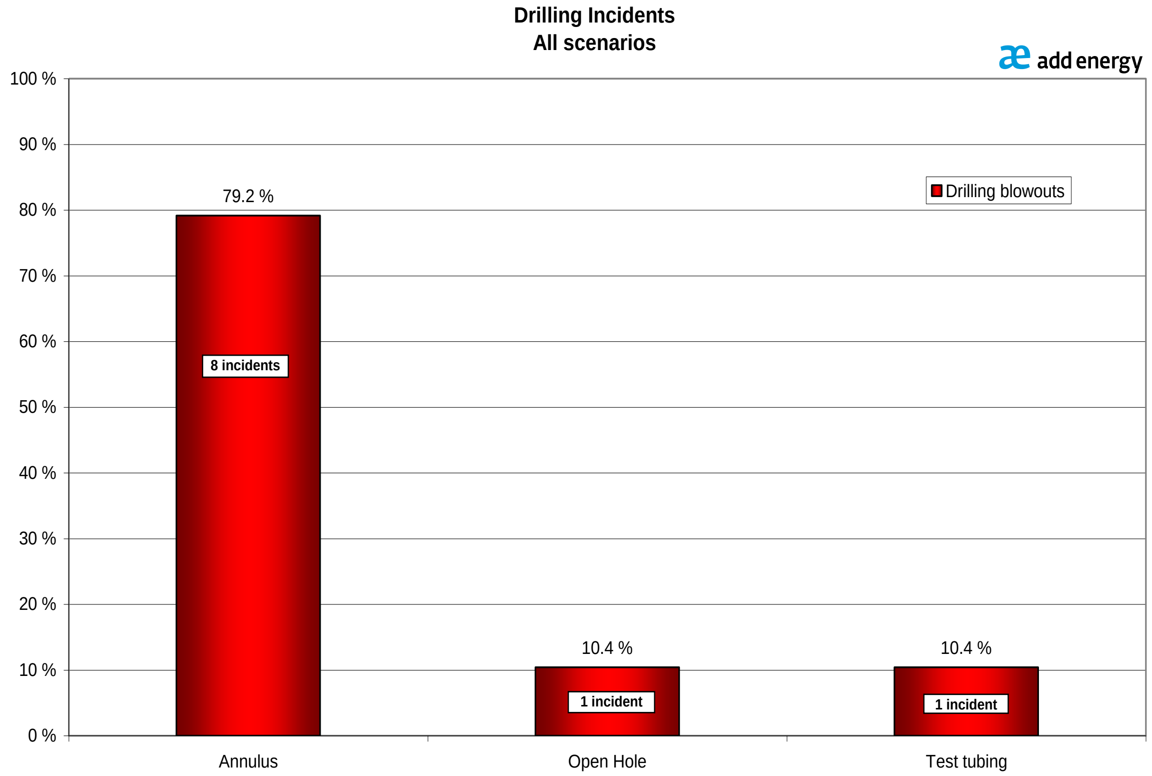

Figure 4.1: Flow path distributions for blowouts from 1980, deep target.

As can be seen, there is a limited number of blowouts being representative for operations on the NCS. The worst-case open hole scenario is represented with only one incident (ARCO in GOM in 1992).

Remarks:

The Macondo incident in the GOM in 2010 is typically not included in the data base as it is not classified to follow the Norwegian standard. This is because no acoustic backup system was installed on the BOP control system. (The absence of this backup system is not recognized as key factor to the blowout and it can therefore be argued that the blowout should be included in the statistics valid for the NCS). The Macondo blowout is categorized under flow path "A. Trough drillstring" and "B. Trough annulus". The drillpipe on the Macondo blowout was open ended and installed ~1000 meters below the seabed. Hence, the flow path was open hole from 1000 m and down to TD at 5600 m.

Similarly, the Montara blowout in 2009 was also an open hole blowout, but is not categorized as "North Sea Standard" and not included in the statistics for blowouts representative for NCS.

4.6 Control method of blowouts

Historically, a majority of all blowouts have stopped by bridging, see Figure 4.2 showing loss of well control events between 2000 and 2015, in regulated areas including US Gulf Of Mexico. Whether a blowout will stop naturally or not depends on several factors and cannot easily be accounted for in a blowout contingency plan. For drilling blowouts from target consolidated reservoirs bridging is less likely than for blowouts from shallow unconsolidated reservoirs.

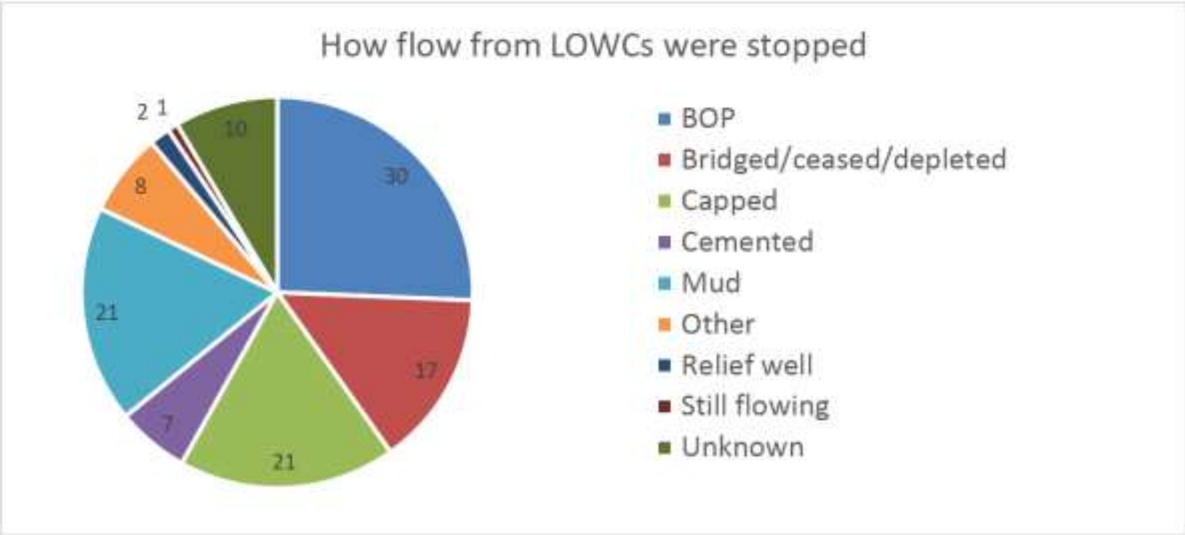

Figure 4.2: Control methods for incidents between 2000–2015, ref.5.

Table 4.2: How events are stopped, 2000–2015, regulated areas, ref.5.

Main Category	Control method	Phase of operation										Total
		Development drilling		Exploration drilling		Comp-letion	Work-over	Produ-ction	Wire-line	Aban-doned well	Un-known	
		Deep	Shallow	Deep	Shallow							
Blowout (surface flow)	BOP			1			1		1			3
	Bridged/ceased/depleted	1	4	4	1	1	1					12
	Capped	1	1	3			3	3				11
	Cemented		2	1								3
	Mud		3	1	4		6			1		15
	Other							1				1
	Relief well	1						1				2
	Unknown				1	1		2		1	1	6
	Still flowing							1				1
	Total	3	10	10	6	2	11	8	1	2	1	54

5. The Macondo Blowout

5.1 Experience from incident

The authors of this report were involved in both the Blowout Task Force and in the BP Internal Investigation Team of the Deepwater Horizon accident in 2010. Authors also testified as expert witness during the litigation following the incident and testified in US district court of Louisiana in April 2013. The experience transfer from this incident is important for the ongoing work related to blowout contingency planning and risk assessments in general, but also for relief well planning in particular.[3]

5.2 Overview of the incident

On April 20th 2010, a fire and explosion occurred onboard the Deepwater Horizon rig while it was working on the Macondo well prospect offshore Louisiana. The rig had cemented the casing and complications occurred during and after performing a negative test, which is a standard procedure to test the cement job. Explosions occurred with subsequent fire and uncontrolled flow of hydrocarbons and a total loss of well control. The rig sank April 22nd. On July 15th, after 87 days of flow, the blowout was controlled by closing in the valves on the capping stack that was installed on the wellhead. On August 3rd, the well was bullheaded and cement was pumped the day after.

BP's investigation team did not identify a single action or inaction that caused the accident. Rather, a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces came together to allow the initiation and escalation of the accident.

BP's blowout task force initiated a massive response operation. Initially, attempts were done trying to close the blowout preventer (BOP) using remotely operated vehicles (ROVs). Several top kill attempts were done trying to pump various fluids into the BOP without success. On June 3rd, 2010, BP removed debris and the damaged drilling riser from the top of the blowout preventer and covered the pipe with a cap which was connected to a riser. On June 16th, a second containment system connected directly to the blowout preventer in order to produce oil and gas to vessels. On July 10th, the containment cap was removed and replaced with a better fitted cap. Mud and cement were later pumped in through the top of the well to reduce the pressure. On July 15th, the final capping stack was installed, it's valves were closed and the flow was finally shut off. There were a sequence of active control operations performed before well control was reestablished on July 15th. Some of these efforts had an impact on the flow rate.

In addition, there was initially a restriction in the flow path caused by a partly sealing annular preventers around the drillpipe. The later retrieved drillpipe showed that this was totally eroded. Furthermore, simulations showed that initially, a fraction of the total reservoir thickness was exposed to the wellbore through the cement. It is possible that these initial small channels in the cement were eroded and more of the reservoir

[3] According to the SINTEF Offshore Blowout Database, the Macondo incident is not regarded as applicable to North Sea conditions (see Section 4.4). However, for the scope of this study and the evaluations on pressure depletion, the incident is relevant.

became exposed with the effect of increased flow. The blowout followed a dynamic behavior caused by both response efforts and change in restrictions.

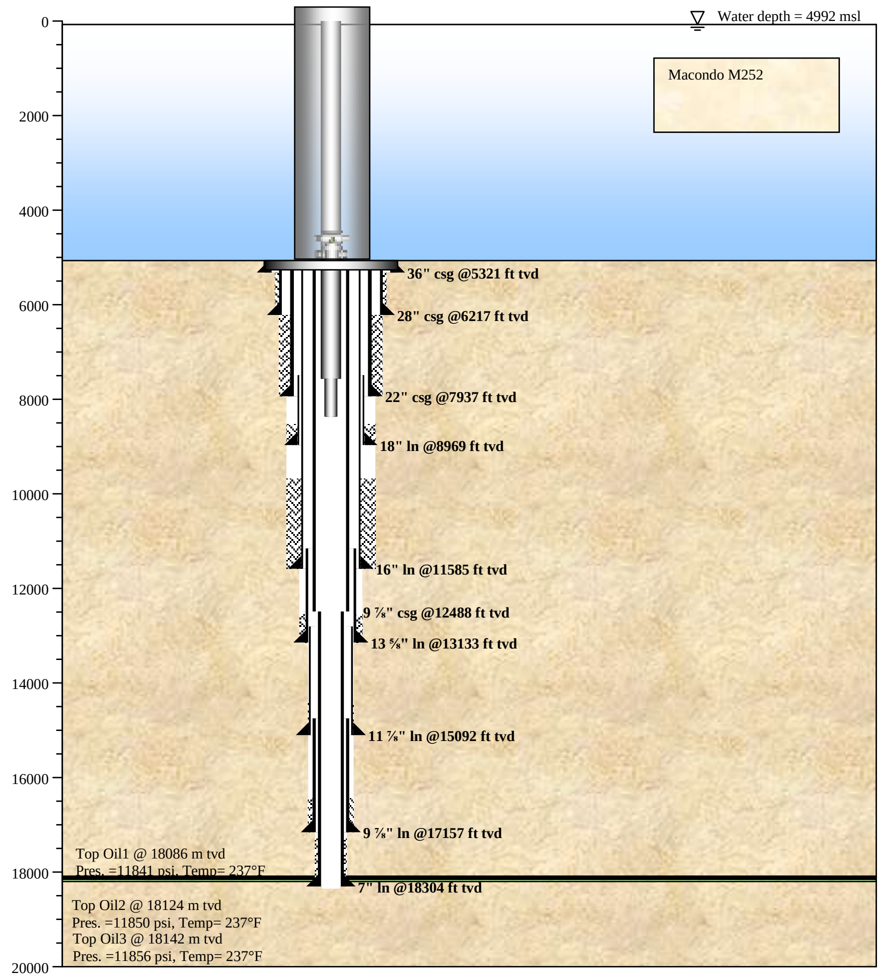

Figure 5.1: Macondo well schematic, TVD drawn to scale

5.3 Reservoir Depletion

The initial / virgin reservoir pressure on the Macondo well was 11850 psi / 817 bar, see ref. 15 and ref. 16. After shut-in of the wellbore, the simulated reservoir pressure showed 10300 psi / 710 bar (ref 14). The estimated total release was 4.9 million barrels (780 000 m³) with an initial flow rate estimated to 62 000 stb/d. Even for this high blowout rate, the reservoir depletion was only 13 %.

On August 3rd, 2010, a bullheading operation was performed to displace the hydrocarbons in the wellbore with 13.2 ppg mud. Prior to the operation, simulations were performed predicting the decline in pump pressure with time. The actual operational data aligned well with the simulated pressure.

6. The Montara Blowout

6.1 Experience from the incident

The authors of this report were involved in the Blowout Task Force of the Montara accident in 2009 planning the relief well kill operation. The team was present offshore on the relief well drilling rig, supervising the actual operation. The experience transfer from this incident is important for the ongoing work related to blowout contingency planning and risk assessments in general, but also for relief well planning in particular. The incident is also an important example of developments in reservoir and flow conditions, not becoming more favorable but rather worsen the conditions at the time of relief well kill.

6.2 Overview of the incident

The Montara blowout occurred in the Timor Sea, off the northern coast of Western Australia, on August 21st 2009. The blowout continued for 75 days before it was controlled by a relief well kill operation on November 3rd 2009.

The first kill attempt happened on November 1st 2009 where the relief well successfully drilled through the 9 ⅝" casing of the blowout well and achieved intersection. The pump rate of 1.3 sg kill mud was rapidly increased to 67 bpm. Gradually, the gas plume reduced to a minimum and kill mud was observed at surface. The pressure while drilling (PWD) tool readings on the relief well indicated that the downhole pressure at the intersection point was too low to stop the influx. As the mud pits were running low, the pumps were cut back and the relief well was closed in on the annular preventer. The mud pumps were lined up to seawater, and pumping continued at about 15 bpm down the drillpipe and 15 bpm down the annulus. At 12:05 hrs, the Montara wellhead platform caught on fire.

On November 3rd, at 13:50 hrs, milling continued while pumping seawater to confirm clear passage into the blowing wellbore. A revised kill plan including additional volumes of mud was initiated by pumping 1.60 sg mud down both the annulus and the drillpipe of the relief well. The pump rate was rapidly increased to 67 bpm. After having pumped about 2600 bbls of 1.60 sg mud, the down hole pressure was sufficient to stop the influx, and the pump rates were reduced. The flames on the Montara Wellhead Platform was diminishing and kill mud observed flowing out of the well. After having pumped a total of 3082 bbls of 1.60 sg mud, the pumps were switched to 1.30 sg mud and pumping continued at reduced rate to fully displace the wellbore to 1.30 sg mud. The blowout was finally killed.

6.3 Reservoir depletion

The Montara reservoir comprised a thick gas cap above the oil zone, trapped within a tilted fault block. The Montara H1 ST-1 well had a 9 ⅝" casing landed in a good horizontal reservoir section of the oil leg.

Initially the blowout produced a moderate rate of oil from the oil leg of the reservoir. The well flowed unrestricted inside the 9 ⅝" casing. When the relief well intersected 74 days after the well blew out, the majority of the flow was coming from the gas cap at a very high rate. At the time of kill, no depletion was observed.

7. Examples of reservoir depletion calculations

7.1 General

Some generic reservoir depletion calculations are presented to provide the reader with some more understanding of the phenomena. Generally, a reservoir can be defined as a rock that has sufficient porosity (void space) to store volumes of hydrocarbons and sufficient permeability (fluid flow capability) to be able to deliver hydrocarbons to the well.

7.2 Calculation examples

Simple calculations have been performed to evaluate the possible depletion using simple tank model. The model includes an Equation of State (EOS) to calculate the compressibility of the fluid but neglects any potential natural pressure supported systems with underlying aquifers etc. that might cause the calculated depletion to be conservative.

For simplicity, for all the examples, the duration of the blowout is 60 days. The blowout potentials are valid estimates of worst-case blowout rates on the respective fields. The reservoir volumes are taken from NPD (Felt på norsk sokkel - Norskpetroleum.no). The two largest reservoirs are Troll and Ormen Lange. Since these two are less likely to be subject to depletion in the due course of a blowout, two smaller fields are also included, Kristin and Valemon. Both Kristin and Valemon are fields subject to significant depletion over the course of a 60-day blowout assumed a constant maximum flow rate over the duration.

As can be seen, the reduction in pressure ranges from 0 to 24 % of the initial pressure. The reduction assumes a maximum flow in 60 days. If the flow rates are less, the resulting depletion is reduced.

Table 7.1: Calculated reservoir depletion for example reservoirs

Field	Original [1] Gas in Place [GSm³]	Original pressure [bar]	Continuous Blowout rate [MSm³/d]	Res. Pres. after 60 days [bar]	Reservoir Depletion[2] [bar]
Troll gas	1437	157	13	157	0
Ormen Lange	346.6	375	34	371	4
Kristin	34.9	894	20	720	174
Valemon	18.8	788	39	595	193

1 Felt på norsk sokkel - Norskpetroleum.no

2 Average pressure after 60 days of flow

8. Depletion observed on real blowouts - Case studies

8.1 General

Add Energy has since 1989 been involved in 80 major blowouts with severe release of hydrocarbons. This Chapter lists some of these with high-rate gas rate flowing from prolific reservoirs. Not all of the blowouts are candidates that are credible for conditions on the NCS, but they will supply data and understanding to the effect of reservoir depletion during the timeframe of blowouts. The depletion mechanism is driven by reservoir size, reservoir fluid and blowout rate (and natural pressure support if present) and are similar regardless of the location, well design and drilling operation.

An important consideration for all these kill operations is that the kill operations were designed using the initial pore pressure, i.e., no depletion were estimated and credited for the kill operations.

8.2 Gas blowout in India 2020

A well control incident occurred during workover operations where the production tubing was perforated to produce from a new interval. As a consequence, the ongoing operations had to be immediately suspended and the well started releasing natural gas in an uncontrolled manner. An explosion followed the influx and flow. Two firefighters died and four other fire fighters suffered injuries.

A capping stack was successfully installed 83 days after the incident, but the well was not shut-in due to well integrity issues. A 2 ⅞" pipe was snubbed into the wellbore at the blowout was dynamically killed 173 days (almost 6 months) after the incident. No signs of reservoir depletion were observed during the kill operation.

Table 8.1: Blowout in India, 2020

Flow path	Inside 5 ½" tubing
Exit point	Surface
Last casing	Perforated 5 ½" tubing
Rate	Initial 5.9 MSm³/d – 5.4 MSm³/d with flow on diverters
Res pressure	403 bar
Res depth	3800 m
Res temp	95
Control method	Capping, snubbing and dynamic kill
Depletion	No observed depletion

Figure 8.1: Gas blowout in India 2020

8.3 Gas blowout in the USA 2019

Well control was lost with gas, condensate and water flowing to the wellhead of the onshore well. The flow rate was estimated to be 43 mmscf/d of gas, 9800 stb/d of condensate and 2550 stb/d of water. A capping stack was installed and a 2 ⅞" pipe was snubbed into the well to perform a dynamic kill operation. When the kill operation was performed 20 days after the blowout occurred, significant depletion was observed. The reservoir was however tight, and fracking operation were required to maintain the productivity.

Table 8.2: Blowout in the USA, 2019

Flow path	Inside 5 ½" tubing
Exit point	Surface
Last casing	9 ⅝" casing and perforated 5 ½" tubing
Rate	43 mmscf/d
Res pressure	12000 psi
Res depth	13679 ft
Res temp	330 °F
Control method	Capping, snubbing and dynamic kill
Depletion	Significant

Figure 8.2: Blowout in USA 2019

8.4 Underground blowout in the USA 2019

During a fracking operation on an onshore well, a pressure anomaly was observed, and further operations were suspended. After the incident, a subsurface cross flow developed through a leaking 5 ½" casing at around 5275 ft tvd. The fully developed cross flow rate was estimated to be 130 mmscf/d of gas based on previous production rates from neighboring wells and a temperature log. The well was brought to control by snubbing in a 2 ⅞" pipe and a dynamic kill operation was performed 11 days after the incident.

Table 8.3: Blowout in the USA, 2019

Flow path	Inside 5 ½" tubing
Exit point	Cross-flow
Last casing	9 ⅝" casing and perforated 5 ½" tubing
Rate	130 mmscf/d
Res pressure	11500 psi
Res depth	13679 ft
Res temp	224 °F
Control method	Capping snubbing and dynamic kill
Depletion	No observed depletion

Figure 8.3: Underground blowout in USA 2019

8.5 Blowout in Libya, 2011

A blowout occurred in August 2011 in a well in the Intisar D field in Libya. The release of hydrocarbon gas occurred around the 13 ⅜" casing which resulted in complete loss of well control and a large fire. Several attempts were made to pump brine down the 7" tubing, but returns were observed after pumping only 15 bbls which indicated there was a leak in the tubing around ±600 ft. Reports indicated that the wellhead, 16 joints of 7" tubing and 6 joints of 9 ⅝" was blown from the well, while the 13 ⅜" was believed to be intact. There was a back-flow tubing safety valve in place in the nipple above the packer, which was causing an obstruction in the flow. The well was killed by a relief well. There was no observed depletion during the kill operation.

Table 8.4: Blowout in Libya, 2011

Flow path	Flow in 7" and annulus 7" x 9 ⅝" casing
Exit point	Surface
Last casing	9 ⅝" casing at 8917 ft tvd
Rate	250 mmscfd / 7.1 MSm^3/d
Res pressure	4451 psi
Res depth	8970 ft tvd
Res temp	222 deg F
Control method	Relief well
Depletion	No observed depletion

Figure 8.4: Gas blowout Libya 2011

8.6 Blowout in GOM Macondo, 2010

HPHT well drilled with Deepwater Horizon. Complications after casing cement job and negative test. Hydrocarbons entered the well undetected and well control was lost. Flow path through a leaking casing shoe and up through the inside of the casing. Explosions, fire and uncontrolled flow of hydrocarbons. Failure of the BOP; the blind shear ram did not seal the well. Fire lasted 36 hours until the rig sank. 11 people lost their lives. Hydrocarbons continued to flow for 87 days. The reservoir depletion was estimated to be 13 % of the initial pressure.

Table 8.5: Blowout in GOM, Macondo, 2010

Flow path	Open hole
Exit point	Seabed (1500 m)
Last casing	9 ⅞" x 7 casing
Rate	50000 - 60000 stb/d of oil
Duration	86 days
Res pressure	817 bar
Res depth	5513 m
Res temp	114 deg C
Control method	Capping and bullheading
Depletion	107 bar (Reservoir pressure after kill estimated to 710 bar)

Figure 8.5: Macondo 2010, Initial fire-fighting and flow through subsea BOP

8.7 Gas, condensate blowout in Timor Sea, Australia, 2009

The PTT Exploration and Production (PTTEP) operated Montara field is located 675 kilometers west of Darwin, Australia, in the southern Timor Sea. On 21 August 2009, the Montara H1 ST-1 well blew out at surface. The West Atlas was positioned adjacent to and skidded out over the Montara Wellhead Platform at the time of the blowout. The most likely cause of the blowout was believed to be a leak at the 9 ⅝" casing float collar. The blowout was killed through a relief well pumping at 67.2 bpm using 1.6 sg mud. A staged kill operation was required using both 1.6 sg and 1.3 sg mud. No reservoir depletion.

Table 8.6: Gas, condensate blowout in Timor Sea, Australia, 2009

Flow path	Open hole (flow in 9 5/8 casing)
Exit point	Surface
Last casing	9 ⅝"
Rate, gas	15 – 75 – 450 mmscf/d
Res pressure	272 bar
Res depth	9 ⅝" @ 2654
Res Temp	110 deg C
Control method	Relief well
Depletion	Initially flowing moderate rate of oil. When Relief Well intersected 74 days after the well blew out, the flow was mainly coming from the gas cap at very high rate. No depletion was observed.

Figure 8.6: Gas blowout in Timor Sea, Australia, 2009.

8.8 Gas blowout in Syria 2007

The Omar-215 well was spudded November 15, 2006 in the Northern part of Syria close the Iraq border. The well was drilled through Shiranish formation at 2952 m underbalanced and depleted 3000 bbls of hydrocarbons. The well was further drilled to 3338 m and POOH to change bit. Hole was tight when going back, required washing and reaming to bottom. The drillpipe parted at Kelly saver sub and dropped 28 m. Well then kicked while attempting to fish the drillpipe. The well was killed through a relief well with flow through choke manifold on the blowout well and into diverters.

Table 8.7: Gas blowout in Syria 2007.

Flow path	Annulus between 5" Drillpipe and 7" casing/open hole
Exit point	Surface
Last casing	7" casing at 2231 m tvd
Rate, gas	30 mmscf/d
Res pressure	382 – 482 bar, multiple zones.
Res depth	2357 m tv
Res Temp	142 deg C
Control method	Relief well
Depletion	No observed depletion

Figure 8.7: Gas blowout in Syria 2007.

8.9 Offshore gas blowout in China, 2007

As a part of an exploration and production program in Chengdu, Sichuan Province, Peoples Republic of China, the operator drilled the Jiao60-5B well in the Bajiaochang Field. The operator was Burlington Resources, an oil and gas company acquired by ConocoPhillips in 2006. On May 27th 2007, the well started to flow gas after the following key events:

- Drill 8 ½" hole with 16.5 ppg mud through tight formations to 2836 m
- Pull out of hole in order to replace the bit and inspect the BHA
- Start run back in hole with new bit
- Well observed to flow with only 30 m of drillpipe (BHA) into the hole
- Well shut-in, annular pressure increases to 1550 psi

The well was finally circulated dead after stabbed in drillpipe to TD.

Table 8.8: Offshore gas blowout in China, 2007

Flow path	Open hole (drill pipe pulled out of hole)
Exit point	Surface
Last casing	9 ⅝"
Rate, gas	Unknown
Res pressure	7800 psi
Res depth	2776
Res Temp	100 deg C
Control method	Circulated through drillpipe
Depletion	No observed depletion

8.10 Oil blowout on a production well onshore Nigeria, 2006

Shell was the operator for the onshore Yorla-13 well in Nigeria. The well was shut in 1993 due to safety issues in the Ogoni area. On about August 23, 2006, the wellhead on Yorla-13 was damaged as a result of apparent vandalism. Well control was lost and the well caught fire with a later reported flame height of approximately 90 ft. The well was capped and a bullhead kill operation performed.

Table 8.9: Oil blowout on a production well onshore Nigeria, 2006.

Flow path	Annulus flow between casing and dual completion string.
Exit point	Surface
Last casing	9 ⅝ casing at 10 549 ft tvd
Rate, gas	12 mmscfd of gas and 9500 bopd
Res pressure	3649 psi
Res depth	9398 ft
Res Temp	195 deg F
Control method	Capping and bullheading
Depletion	No observed depletion.

Figure 8.8: Oil blowout on a production well onshore Nigeria, 2006.

8.11 Gas blowout in Texas, USA, 2005

Onshore gas blowout in Texas, USA. The vertical exploration well was drilled to assess commercial hydrocarbon potential of the Yegua and Cochran sand packages. On May 31, 2005, while drilling 9 ⅞" hole at a depth of 11,137 ft with 11.8 ppg mud a kick was taken. While circulating the calculated kill mud density of 12.5 ppg the well started leaking at the Braden Head Flange (BHF). The well was opened to the pit via the panic line while continuing to pump kill mud down the drillpipe. The well blew out at the BHF at midnight and caught fire at 01:00 on June 1, 2005. The well was initially flowing gas, saltwater and reported flowing large volumes of sand, the flow was initially reported as coming from the cellar and not the drillpipe and throwing golf ball sizes of cement and formation. The well continued to flow from the cellar area until June 13, when the fire went out. A suspected underground flow was assumed ongoing after June and until the well was killed with a relief well.

Table 8.10: Gas blowout in Texas, USA, 2005.

Flow path	Annulus flow. 5" dp and 9 ⅞" open hole
Exit point	Surface through wellhead
Last casing	10 ¾" at 2865 ft tvd
Rate, gas	50-170 mmscfd
Res pressure	4136-8673 psi, multiple zones
Res depth	8380 ft to 11130 ft
Res Temp	80-100 deg C
Control method	Relief well
Depletion	No observed depletion

Figure 8.9: Gas blowout in Texas, USA, 2005.

8.12 Oil and gas blowout in Uzbekistan, 2004

An appraisal well was drilled in the mountains of Uzbekistan close to the Afghanistan border. It was completed to 2637m md inside the oil rim and a 7" casing was run in the well. The 9 ⅝" casing was set at 2069 m tvd approximately 6 m above the top of reservoir gas cap. During cementing of the casing the well started flowing on the back side. Shortly after the well was shut-in gas started flowing out of a hole in the wellhead and the rig site was abandoned due to the potential explosion hazard and expected H_2S content of the gas. Well accidentally caught fire. Well capped and then bullhead kill operation was performed.

Table 8.11: Oil and gas blowout in Uzbekistan, 2004

Flow path	Annulus flow between 7" casing and 9 ⅝" casing
Exit point	Surface/leak in wellhead
Last casing	7" casing
Rate, gas	Initial 36 mmscf/d gas and 500 Sm^3/d oil. Increased to 56 mmscf/d and 800 Sm^3/d of oil after well capped
Res pressure	232 bar (3360 psi)
Res depth	2075 m tvd
Res Temp	80 deg C
Control method	Capped and bullheading
Depletion	No observed depletion

Figure 8.10:Oil and gas blowout in Uzbekistan, 2004

8.13 Gas blowout on a production platform offshore Brunei, 2001-2002

Gas blowout on a production platform offshore Brunei in 11 m water depth. On 24th December 2001, a drilling break was observed while drilling the 12 ¼" hole of South West Ampa (SWA) 184 sidetrack (ST) at 3073 m. The well was flowing, and it was shut in at 1915 hours on 24th December 2001. On discussion with the rig team and onshore team, it was decided to circulate the gas out prior to displace the hole with a kill mud. While circulating the gas out mud losses were observed. Circulation continued until 0535 hours on 25th December 2001. While preparing the kill mud it was observed that the annulus pressure was increasing, and bubbles were observed around the conductor. The bubbles got worse, and the tender was pulled away from the AMDP/15 platform. Gas and water flowed until 9 pm the same day before the well bridged off. It was suspected that a cross flow was ongoing, which was later confirmed while running temperature and noise logs inside the drillpipe. The well was killed by drilling a relief well which intersected directly into the open hole above the flowing formation.

Table 8.12: Gas blowout on a production platform offshore Brunei, 2001-2002.

Flow path	Annulus between Drillpipe and 12 ¼" open hole
Exit point	Surface. Bridged off and continued to flow underground.
Last casing	13 ⅜" casing
Rate, gas	08 mill Sm3/d of gas and around 50 000 bwpd
Res pressure	220-350 bar, multiple zones
Res depth	2200-2800 m
Res Temp	98 deg C
Control method	Relief well
Depletion	Depletion of the gas pocket kicking off the flow, but no depletion of the main gas reservoir

Figure 8.11: Gas blowout on a production platform offshore Brunei, 2001-2002.

8.14 Gas blowout during logging, Indonesia 2002

A barge drilling in Indonesia stopped at 4744 m penetrating an unexpected high pressure zone. The former 9 ⅝" x 7"' casing shoe was set at 4449 m. The oil base mud weight was increased and the decision was taken to pull out of hole for electrical logging. During the trip out proper monitoring of well stability was made and several well instability shows were detected through total gas increase during circulation at casing shoe for repeat section of LWD and then, through wrong fill up data. Heavy logging tools including two radioactive sources were then run in hole.

When logging tools reached 4405 m, the well started to flow. An attempt to pull out of hole the logging tools had to be stopped at 3900 m as the well flow dramatically increased. The Tool Pusher closed the annular preventer on the electric line, opened the upper HCR to monitor the wellhead pressure which already reached 90 bar and increased rapidly to 250 bar, this pressure increase was accelerated by intensive bleed off to try to limit WHP below. When the annular preventer started to leak and the electric line broke at surface, the Tool Pusher closed the shear rams and then opened the lower HCR valve to monitor the wellhead pressure which rapidly reached 315 bar, the leak through the BOP was still developing. When WHP reached 315 bar the well started to blow out through the rotary table. The rig was evacuated, it ignited 2h30 later. The drilling package collapsed rapidly. The well partially bridged after few hours. More than six weeks work were needed to remove the drilling package debris to tow the Maera barge out of the location and cap the well with an emergency wellhead and BOP. Snubbing used to fish the logging tool and kill the well. A relief well was drilled as a contingency.

Table 8.13: Gas blowout during logging, Indonesia 2002.

Flow path	Up 7" casing with logging tools & wireline in hole
Exit point	Surface with 3.0" ID choke restricting at outlet
Last casing	9 ⅝" x 7 csg
Rate, gas	Initial rate 95 mmscf/d of gas, dropped to 0.3 mmscfd
Res pressure	517 bar
Res depth	3754 m tvd
Res Temp	127 deg C
Control method	Capping, snubbing and circulation
Depletion	No depletion, well bridged off

Figure 8.12: Gas blowout during logging, Indonesia 2002.

8.15 HPHT Gas blowout in Mississippi, USA, 2001

An onshore well in Mississippi blew out on February 13th 2001 while running 4 ½" liner in the well. The well had been drilled to 18500 ft and 7 ⅝" casing was set at 17044 ft. After the well blew out the flow was ignited to reduce the explosion hazard. The reservoir fluid contained H_2S and evacuation of people located in the area was initiated. The wellhead was cut off on February 20th using the Halliburton hydraulic jet cutter. The well was capped on fire on February 24th and the flow was directed to a flare pit using three 4-inch diverter lines. After the well was capped leaks was detected at one of the wellhead valves in the B-section and it was therefore critical to avoid putting any pressure on the wellhead during the kill operation. The well was dynamically killed through a snubbed in 3 ½" tubing which could be achieved without putting any significant amount of pressure on the wellhead during the kill operation.

Table 8.14: HPHT Gas blowout in Mississippi, USA, 2001.

Flow path	6 ¼" open hole, Annulus: 7 ⅝" csg x 3 ½" dp + diverters
Exit point	Surface – through vent lines and choke manifold
Last casing	7 ⅝
Rate, gas	80-120 mmscf/d
Res pressure	15380 psi
Res depth	18500 ft
Res Temp	300 deg F
Control method	Capping, snubbing and dynamic kill
Depletion	No depletion, tight reservoir.




Figure 8.13: HPHT Gas blowout in Mississippi, USA, 2001.

8.16 Gas and water blowout offshore Malaysia, 2001

A gas and water blowout on an offshore well in 131 ft of water of the coast of Malaysia. Blowout occurred while drilling 12 ¼" after setting 13 ⅜" csg. Flow was directed out through two 12" diverter lines at the rig floor. The well bridged after 1 day. Underground flow from reservoir up 12 ¼" open hole (with 5" DP in hole), out directly below 13 ⅜" csg.

Table 8.15: Gas and water blowout offshore Malaysia, 2001.

Flow path	Annulus between 5" dp and 12 ¼" open hole – 13 ⅜" casing
Exit point	Surface – Out through diverter lines on the jack-up rig.
Last casing	13 ⅜
Rate, gas	2.9 MSm^3/d
Res pressure	48.6 bar
Res depth	1653 ft
Res Temp	32 deg C
Control method	Bridged off
Depletion	None – bridged off after 1 day

8.17 Gas blowout onshore Azerbaijan, 2001

Oil and gas blowout on a land well in Azerbaijan. Flow of oil and gas up 13 ½" casing through open casing head valve. Flow of gas, oil and water in geysers around the well site. Sheared DP to remove rig. Well bridged but geyser still flowing. Pumped cement down drillpipe to kill well.

Table 8.16: Gas blowout onshore Azerbaijan, 2001.

Flow path	Flow on outside of 9 ⅝" casing to surface and out through fractures with release to surface craters.
Exit point	Through geyser at surface around the well site.
Last casing	9 ⅝" casing
Rate, gas	Unknown
Res pressure	
Res depth	1447 m
Res Temp	50 Deg C
Control method	Pumped cement down drillpipe
Depletion	Bridged off

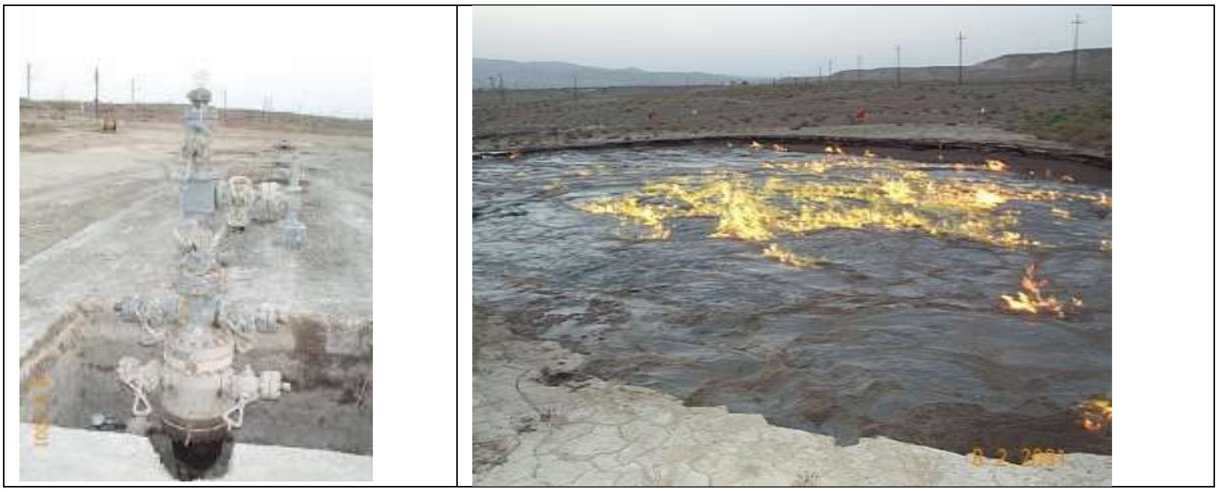

Figure 8.14:Gas blowout in Azerbaijan. Gas geyser from fractures, 2001

8.18 Gas blowout in Oklahoma, USA, 2001

Gas blowout onshore Oklahoma, USA. A kick was taken while drilling into the reservoir at 1055 ft tvd after the 9 ⅝" casing was set. The well was shut in on the BOP and flow directed out through the vent line. The fracture pressure on the last casing shoe could not hold the expected shut-in pressure. Flow was up the annulus of the 4 ½" drill pipe and 8 ½" open hole and the 9 ⅝" casing. The well was killed by pumping down the drillpipe of blowing well.

Table 8.17: Gas blowout in Oklahoma, USA, 2001.

Flow path	Annulus between 4 ½" dp and 9 ⅝" casing and 8 ½" open hole.
Exit point	Surface – through vent line
Last casing	9 ⅝" casing
Rate, gas	30 mmscf/d
Res pressure	435 psia
Res depth	1055 ft tvd
Res Temp	83 deg F
Control method	Pumping down drillpipe
Depletion	Limited reservoir extent. Significant depletion.

8.19 Gas blowout on a storage field in Hungary, 2000

During a workover on a well in a gas storage field in Hungary, control of a swab kick was lost and a blowout and fire resulted. Reservoir pressure was near seasonal high and production from the well was predicted at ~3.8 MSm³/day. The gas source was a pipeline from Russia and the well that blew out was one of several wells that were used as producers during winter and injectors during the summer season. A 6 m perforated interval at 1229 m MD into a Darcy+ permeability sandstone was the main production interval along with possible communication with shallower zones containing gas and water. The Hungarian wild well firefighting team successfully capped the well in two weeks. However, after the bullhead operation an adjacent well cratered and the capping stack was opened to relief pressure. The casing had burst near the surface and the resulting sand erosion destroyed the capping stack and the well eventually cratered producing large volumes of formation water. A relief well was drilled and the well was killed pumping water at moderate rates. Flow restricted by partly bridge of lower sand.

Table 8.18: Gas blowout on a storage field in Hungary, 2000.

Flow path	Annulus
Exit point	Surface
Last casing	7" csg (and 3 ½" tbg)
Rate, gas	3.8 MSm³/d depleted to 1 MSm3/d
Res pressure	130 bar
Res depth	1229 m
Res Temp	80 deg C
Control method	Relief well
Depletion	High depletion, known reservoir size.

Figure 8.15: Gas blowout on a storage field in Hungary, 2000

8.20 Gas blowout in Algeria, 2000

Well HR64 was drilled in 1977 on land in the Algerian desert and put on production on September 1980. Operator indicated, severe corrosion is possible in 9 ⅝" casing and also the cement bond logs indicate poor cement behind 9 ⅝" casing as well as between the 9 ⅝" casing and the 7" liner. During a workover on the well on January 18, 2000, a rapid gas kick was taken with bit at 562 m. The well was shut-in on pipe rams with 3500 psi. Crew attempted to stab drillpipe valve without success due to high flow. Blind rams where then closed on 5" DP in attempt to crimp pipe and reduce flow but was not successful. The site was evacuated, and the gas flow ignited shortly after. The drillstring was ejected from the wellbore. The well was capped on fire and killed from a snubbing unit.

Table 8.19: Gas blowout in Algeria, 2000.

Flow path	Flow up 7" casing and in annulus 3 ½"dp upper part
Exit point	Surface
Last casing	9 ⅝" csg and 7" ln
Rate, gas	5.5 MSm^3/d
Res pressure	192 bar
Res depth	2100 m
Res Temp	90 °C
Control method	Capping, snubbing and dynamic kill
Depletion	None – extremely large gas reservoir




Figure 8.16: Gas blowout in Algeria, 2000.

8.21 Gas blowout in Texas, 2000

Gas blowout in Texas, USA. Took kick while drilling reservoir section in a gas reservoir after 7" casing was set. BOP closed in and flow put on diverter lines since the surface equipment could not take the shut-in pressure. Well killed by pumping heavy mud from surface through drill pipe.

Table 8.20: Gas blowout in Texas, 2000.

Flow path	Annulus between 7" casing and 3 ½" drill pipe
Exit point	Through surface equipment and vent line
Last casing	7" casing
Rate, gas	50 mmscfd
Res pressure	8730 psi
Res depth	10 400 ft
Res Temp	100 Deg C
Control method	Pumping down drillpipe
Depletion	No depletion observed

Figure 8.17: Blowout in Texas, 2000.

8.22 Underground gas blowout/crossflow offshore Australia 2000

Well kicked while running in hole with 7" liner, 90 m below wellhead. Pressure quickly built up to 3500 psi at surface with gas and condensate at the choke (assumed gas to surface and mud jetted out in the Flag SS formation). The well was cross flowing between two high permeable sands. Restrictions in surface equipment during initial release at rig.

Well killed by stripping pipe and dynamically killed the well through the drillpipe.

Table 8.21: Underground gas blowout/crossflow offshore Australia 2000.

Flow path	Flow in 8 ½" open hole (5" dp pulled out)
Exit point	Into sand matrix at 2200 m
Last casing	9 ⅝" casing at 1700 m
Rate, gas/condensate	100 mmscf/d of gas, 8000 bpd of condensate
Res pressure	4700 psi
Res depth	2700 m
Res Temp	115 deg C
Control method	Stripping in drillpipe and dynamic kill
Depletion	No depletion observed

8.23 Underground gas blowout offshore Bangladesh 2000

A deep gas well was drilled with a Jack-up rig to the top of reservoir at 4700 m, dp became stuck on trip 1000 m off bottom. Abandoned BHA and sidetracked 350 m BHA fish. Took kick at first permeable zone below fish with intensity of gas zone 1000 m deeper. A 9 ⅝" casing was set and continued to drill to objective for testing. After testing completed, concern was raised about gas crossflow and the possibility of broach to shallow zones and the surface. Relief well intersected below fish and killed and plugged well.

Table 8.22: Underground gas blowout offshore Bangladesh 2000.

Flow path	Annulus between 5” dp and 9 7/8” casing
Exit point	Underground (3200 m tvd)
Last casing	9 ⅞" casing
Rate, gas	Unknown
Res pressure	862 bar
Res depth	4700 m tvd
Res Temp	120 deg C
Control method	Relief well
Depletion	No depletion observed.

8.24 Well control incident on HPHT gas well, 1999

A deep HPHT gas well was completed with a reservoir at 17 500 ft tvd. A gas kick was taken in the annulus due to leaking production tubing. The well was put on emergency production through 2 ⅞" x 3 ½" tubing strings and through partly closed subsea safety valve.

Well kill by bullheading heavy mud down tubing and annulus simultaneously.

Table 8.23: Well control incident on HPHT gas well, 1999.

Flow path	Flow in 2 ⅞" x 3 ½" tubing to surface and also in annulus between 3 ½" tubing in shallow part of well
Exit point	Through surface equipment and into flowline
Last casing	11 7/8 casing at 15300 ft (7" liner at td)
Rate, gas	85 mmscf/d of gas
Res pressure	16 800 psi
Res depth	17 500 ft tvd
Res Temp	370 deg F
Control method	Bullheading (both annulus and tubing)
Depletion	No depletion observed.

8.25 Gas blowout on production well in GOM, 1999

The well was drilled on Ship Shoal Block 353 through a sub-sea template in July 1996 as a replacement for a well from an adjacent platform. The well was later tied back to a production platform and completed through a gravel pack in May 1998. Steady decline in well performance led to a recommendation to stimulate the well. An acid stimulation job was performed. The completion soon began to produce sand, however, and cut out surface chokes. On September 9th, 1999, mechanical problems were encountered while setting the bridge plug which required the setting of a second plug above the first. The well blew out while attempting to run in the hole with the second bridge plug on coil tubing. The coil was partly ejected and flow was coming through the tubing with the coil restricting the flow inside. A relief well was initiated, but successful capping operation was performed, and the well was bullheaded dead by pumping brine down the tubing.

Table 8.24: Gas blowout on production well in GOM, 1999.

Flow path	Up through production tubing with coil inside
Exit point	Surface – drill floor through sand cut master valve
Last casing	7 ⅝" casing
Rate, gas	1 mmscf/d of gas
Res pressure	8500 psi
Res depth	13 500 ft
Res Temp	200 Deg F
Control method	Bullheading
Depletion	No depletion observed.

Figure 8.18: Gas blowout on production well in GOM, 1999.

8.26 Gas blowout in California, USA 1999

The HPHT well was drilled onshore in California penetrating the target reservoir at 17640 ft tvd. Well control was lost when taking a gas kick and full flow of gas was exiting at surface. The flow path was up in the annulus of a 3 ½" dp and 7" liner, through a leak in a mechanical bridge plug and further up in the annulus between 5" dp and 9 ⅝" casing. Part of flow was also leaking through a hole in the casing and fracturing into the formation at the 13 ⅜" casing shoe. The well was flowing both gas and water and after it was put on emergency production the rate was 15 mmscf/d of gas and 25 000 bwpd in addition to associated condensate. Significant restrictions in the flow through the mechanical plug at 11 485 ft tvd. The well was killed with a relief well after a successful capping operation but unsuccessful kill attempts from surface.

Table 8.25: Gas blowout in California, USA 1999.

Flow path	Annulus flow between Drillpipe and casing/liner. Flow also info fractures and casing leaks.
Exit point	Casing leak and surface through production string connected to wellhead. Initially total annulus release at surface
Last casing	9 ⅝" csg x 7" ln
Rate, gas-water	15 mmscf/d of gas – 25 000 bwpd
Res pressure	15100 psi
Res depth	1760 ft tvd
Res Temp	360 deg F
Control method	Relief well
Depletion	No depletion observed.

Figure 8.19: Gas blowout in California 1999. Rig and equipment on fire.

8.27 Gas blowout in Wyoming 1998

Onshore gas blowout in Wyoming USA. HPHT well with high initial gas rate of 250 mmscf/d which later dropped to around 40 mmscf/d when the well was put on emergency production. The well was intentionally put on fire to reduce gas ignition risk in the area. Well bridged and restricted the annulus flow. Drillpipe was partly collapsed as well as casing flow. A relief well was close to intersect when the well suddenly bridged off and stopped the surface flow.

Table 8.26: Gas blowout in Wyoming 1998

Flow path	Annulus / ann.+ DP
Exit point	Surface
Last casing	9 ⅞" csg
Rate, gas	Initial rate 250 mmscf/d dropped to 40 mmscf/d when on emergency production
Res pressure	13204 psi
Res depth	17058 ft
Res Temp	300 deg F
Control method	Bridged off
Depletion	No depletion observed.

Figure 8.20:Gas blowout in Wyoming, USA 1998

8.28 High rate gas blowout onshore in Bangladesh, 1997

In June 1997 a gas kick was taken from a shallow gas reservoir on an onshore well in the Northeast are of Bangladesh. When the first gas bubbles were observed at surface, the pipe rams were closed and the well was flowing through the 50 m long 12" diverter line. At the time the first gas was observed at surface the pressure at the 20" casing shoe was already exceeding the fracture pressure of 327 psi, resulting in gas flowing into the fractures and out at surface. After a few minutes the gas exploded around the rig site and a constantly burning fire of more than 500 ft was seen at the well site. Later the same day the ground around the well head bridged, resulting in the rig to bend over and finally sinking into the ground. A big crater developed at the blowout well site (more than 100 m in diameter) filled with water with gas flowing up through the water. Small craters were observed around the well site, and at present gas is flowing at surface at a distance of up to 700 m from the original well site. The well was dynamically killed several months later with a relief well.

Table 8.27: High rate gas blowout onshore in Bangladesh, 1997.

Flow path	Up annulus between 5” dp and 17 ½” hole/ 20” csg
Exit point	Several exit points initially at surface and later underground at 300 m, 500 m and 620 m tvd
Last casing	20” casing at 200 m tvd
Rate, gas	Initial rate 450 mmscf/d. Dropped to ~200 mmscf/d
Res pressure	Two zones: 1086 psi and 1225 psi
Res depth	~750 - 850 m tvd
Res Temp	50 deg C
Control method	Relief well
Depletion	No depletion observed on main reservoir. But gas cap was depleted.


Figure 8.21: Initial fire and huge crater. Gas blowout Bangladesh 1997.

8.29 Crossflow on Haltenbanken NCS, 1996

A gas kick was taken on an exploration well on the Haltenbanken area. The size of the kick was influenced by a malfunction of the upper annular on the BOP and the well was shut in using the lower annular. The pressure behavior suggested that the open hole section of the well had been fractured. Temperature logging tools, with 5000 and 10000 psi pressure control equipment was mobilized to evaluate the downhole situation. The logs verified that the well was flowing up to 3950 m.

Well kill from the drilling rig by circulation heavy mud.

Table 8.28: Crossflow on Haltenbanken NCS, 1996.

Flow path	Annulus between 5" drillpipe and 12 ¼" open hole
Exit point	3950 m tvd (Crossflow)
Last casing	13 ⅜" casing
Rate, gas	0.5 mill Sm3/d
Res pressure	850 bar
Res depth	4550 m tvd
Res Temp	163 deg C
Control method	Circulation
Depletion	No depletion observed.

8.30 Gas/oil blowout in Syria 1995

This blowout occurred on an onshore well with 13 ⅜" casing set in well. At the time of the blowout 12 ¼" horizontal curved hole drilled into gas cap planning to set 9 ⅝" casing into oil leg. A gas kick was taken which was not controlled due to hole in casing (casing wear). The well fractured shallow underground and started to flow through craters as well as at surface through annulus and drillpipe. Several unsuccessful attempts were performed of bullheading down drillpipe. The well suddenly ignited and killed 5 people. The well was finally controlled with two relief wells pumping at 120 bpm with water. Three relief wells were drilled with one as backup.

Table 8.29: Gas/oil blowout in Syria 1995

Flow path	Up through annulus initially. Then through drillpipe and craters/fractures underground.
Exit point	Surface through drilldpipe/annulus and through fracters and craters around the wellhead.
Last casing	13 ⅜"
Rate, gas/oil	150 mmscf/d of gas and around 100 000 bopd
Res pressure	3840 psia
Res depth	2794 m tvd
Res Temp	240 deg F
Control method	Two relief wells
Depletion	No depletion observed. Huge gas cap exposed.

Figure 8.22: Gas condensate blowout in Syria, 1995.

8.31 Gas blowout in Vietnam, 1994

An underground crossflow of ~22 mmscf/d of gas occurred offshore Vietnam in the Lan Tay field in 1994. Killed by pumping through a relief well, 5-10 bpm (u-tubing from RW to blowout well).

Table 8.30: Gas blowout in Vietnam, 1994

Flow path	Drilling 17 ½" open hole. Annulus flow
Exit point	Underground flow
Last casing	20" casing
Rate, gas	22 mmscfd
Res pressure	2830 psi
Res depth	1609 m tvd
Res Temp	101 Deg C
Control method	Relief well
Depletion	No depletion observed.

8.32 Onshore gas blowout in Argentina, 1993

During a trip out of the hole for a logging run, the well began flowing when the HWDP was reached. The well was shut-in with the pressure reaching 1200 psi before stabilizing at 900 psi. After circulating kill mud for two days, the pressure reduced to zero and a slick BHA was RIH for a cleanout trip. A bridge was found at the shoe and after drilling 1-1/2 singles, the elly and 4 joints of DP were ejected prior to the shutting in of the BOP. The well was blowing out underground through a highly permeable shallow sand. Plumes and craters had formed at the outcrop of the 20° dipping formation two days after the initial kick. Blowout rates were estimated to be greater than 150 mmscf/d. The well was killed by a combination of relief well and pumping gunk down existing well path.

Table 8.31: Onshore gas blowout in Argentina, 1993

Flow path	Annulus flow and through drillpipe
Exit point	Through drillpipe at surface and through fractures and into craters
Last casing	13 ⅜" casing
Rate, gas	>2.5 MSm³/d
Res pressure	2150 psi
Res depth	1250 m
Res Temp	51 Deg C
Control method	Relief well
Depletion	No depletion observed.

Figure 8.23: Gas blowout in Argentina, 1993.

8.33 Offshore gas blowout (Shallow gas), Vietnam 1993

Gas blowout offshore Vietnam in 1993. Drilling into shallow gas zone with the Semi-Submersible drilling unit Actinia. High gas rate exiting outside the casing at seabed resulted in an unstable buoyancy for the rig and very high gas content in the sea column. Well cratered and stopped by itself.

Table 8.32: Offshore gas blowout (Shallow gas), Vietnam 1993.

Flow path	Outside casing
Exit point	Crater at seabed
Last casing	20” casing
Rate, gas	High rate gas. Exact rate unknown.
Res pressure	1.0 EMW
Res depth	1500 m
Res Temp	Unknown
Control method	Cratered
Depletion	No depletion observed.

Figure 8.24: Actinia drilling rig at the Lan Tay field while gas is blowing out.

8.34 Underground gas blowout, GOM 1992

Gas condensate blowout from HPHT well offshore Gulf of Mexico. Blowout occurred due to leak in 2 ⅞" tubing most likely caused by wear and corrosion (plastic coated tubing). Restricted flow underground through unknown holes in tubing.

Well dynamically killed by pumping heavy mud (18.5 ppg) down production tubing at high pump pressure. Additional pumping equipment installed on rig to facilitate kill operation.

Table 8.33: Underground gas blowout, GOM 1992.

Flow path	Up production tubing and further through restricted holes in the tubing and into fractures
Exit point	Multiple exits points into sands underground ranging from 4500 ft to 13000 ft
Last casing	9 ⅝" casing
Rate, gas	30 mmscf/d of gas with small amounts of condensate
Res pressure	14950 psi (1030 bar)
Res depth	17536 ft
Res Temp	295 deg F (146 deg C)
Control method	Dynamic kill down tubing
Depletion	No depletion observed.

Figure 8.25:GOM gas underground blowout. Pumping equipment installed on the rig.

8.35 Gas blowout in South Texas, 1990

Gas blowout on an onshore production well, South Texas. Blowout occurred when cleaning out reservoir interval. Tapered 3 ½" and 5" drill pipe in the hole. Flow path inside drillpipe to surface. Flow choked back at surface, but unable to shut-in the well. Well killed by bullheading mud from surface at high pump pressure.

Table 8.34: Gas blowout in South Texas, 1990

Flow path	Tubing and annulus. Broached and to surface
Exit point	Surface through tubing and underground
Last casing	10 ¾" casing and 7 ¾" liner.
Rate, gas	52 mmscf/d + 1800 bwpd
Res pressure	14000 psi
Res depth	14700-15100 ft
Res Temp	170 deg C
Control method	Bullheading
Depletion	No depletion observed.

8.36 Onshore gas blowout in Venezuela, 1990

Gas blowout on a production well onshore, Venezuela. Well completed with dual string of 3 ½" and 5" tubing. Comingled flow from two different reservoirs at 17 000 and 15 000 feet respectively. Complicated flow path with downhole and surface restrictions through leaking packers and hole in casing strings. Flow both out at surface through production tubing and broached underground with flowpath to surface around the well location.

Well killed by relief well pumping heavy mud at high rate.

Table 8.35: Onshore gas blowout in Venezuela, 1990

Flow path	Tubing and annulus. Broached and to surface
Exit point	Surface through tubing and underground
Last casing	10 ¾" casing for upper reservoir and 7 ¾" liner lower reservoir.
Rate, gas	Unknown – estimate +/- 1 MSm^3/d
Res pressure	~ 900 bar
Res depth	15 000 ft and 17 000 ft
Res Temp	180 deg C
Control method	Relief well
Depletion	No depletion observed.

8.37 Offshore HPHT well on the NCS, 1989

In January 1989 the shear-ram in Norwegian North Sea exploration 2/4-14 was activated after a high-pressure gas kick hit the surface equipment during coiled tubing operation in the drillpipe. A relief well was spudded shortly after to be used in case the well should start to flow to surface. After reentering the well three months later with snubbing equipment, it was concluded that there was an underground blowout in the well. The well was dynamically killed by relief well intersecting at 4700 m tvd. First relief well intersection without plug back performed worldwide.

Table 8.36: Offshore HPHT well on the NCS, 1989

Flow path	Through drill pipe and further through parted drill pipe into annulus and further underground. Coiled tubing was also present in the flow path.
Exit point	Underground
Last casing	9 ⅝" at 4437 m tvd
Rate, oil	20-30000 bpd
Res pressure	980 bar (14200 psi)
Res depth	4733 m
Res Temp	~ 180 deg C
Control method	Relief well
Depletion	No depletion observed. Limited flow from main reservoir through restricted path into shallow formation.

Figure 8.26: Well 2/4-14 with the relief well rig Treasure Saga in the background.

A. References

1. Activities Regulations, https://www.ptil.no/en/regulations/all-acts/the-activities-regulations3/XV/86/
2. Facilities Regulations, https://www.ptil.no/en/regulations/all-acts/the-facilities-regulations3/II/5/
3. Norwegian Oil and Gas, "Guidance on calculating blowout rates and duration for use in environmental risk analyses", Translated version, 2014. Last rev. 2021.
4. Ray T. Oskarsen; Amir Paknejad; Prasongsit Chantose; Morten Emilsen; Brett Morry, "A Case Study Demonstrating Single Relief Well Contingency for a Prolific Gas Well in Ultra-Deepwater", SPE Annual Technical Conference and Exhibition, Calgary, Alberta, Canada, September 2019. Paper Number: SPE-195961-MS
5. Eric Upchurch; Ray Oskarsen; Prasongsit Chantose; Morten Emilsen; Brett Morry, "Relief Well Challenges and Solutions for Subsea Big-Bore Field Developments", SPE Drill & Compl 35 (04): 588-597. Paper Number: SPE-199550-PA
6. Per Holand, "Loss of Well Control Occurrence and Size Estimators, Phase I and II", 4 May 2017.
7. "Global Natural Gas Reserves – A Heuristic Viewpoint" (PDF). Ipc66.com. Archived from the original (PDF) on 2016-03-04. Retrieved 11 November 2017.
8. Oskarsen, Emilsen, Paknejad, Cargol, and See: "How to Develop a Well Specific Blowout Contingency Plan That Covers Engineering Analysis of the Deployment, Installation, and Soft Shut-In of a Subsea Capping Operation" SPE 181393, SPE Annual Technical Conference and Exhibition, 26–28 September 2016, Dubai, UAE.
9. Oskarsen, Rygg, Cargol, and Morry: "Challenging Offshore Dynamic Kill Operations Made Possible with the Relief Well Injection Spool" SPE 180279, SPE Deepwater Drilling & Completions Conference, 14–15 September 2016, Galveston, Texas.
10. Wright, J.W., Flak, L., "Relief wells: Advancements in technology and application engineering make the relief well a more practical blowout control option", available at: http://www.jwco.com/technicallitterature/p11.htm
11. Maritime New Zealand, "Well Control Contingency Plan Guidance Note", ver. 2 02 December 2015.
12. Rygg, O. B. and Oskarsen, R. T.: "Dual Relief Well Operations, Challenges and Solutions", IADC Well Control Europe 2014, Conference & Exhibition, 2-3 December 2014, Aberdeen, Scotland.
13. "DIRECTIVE 2013/30/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL", 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC
14. US Department of Interior, "Computer Simulation of Reservoir Depletion and Oil Flow from the Macondo Well Following the Deepwater Horizon Blowout", 2010.
15. BP, "Deepwater Horizon Accident Investigation Report", September 8 2010.
16. Emilsen, Morten H., "Dynamic Simulations, Deepwater Horizon Incident", September 8, 2010.
17. Oskarsen, Wright, Rygg, Selbekk & Allcorn, "A Case Study in Relief well Drilling Using a Modified Driller's Method as a Well-Intervention Alternative to Bullheading." IADC Well Control Middle East 2008 Conference & Exhibition, 2-3 December 2008, Muscat, Oman
18. Rygg, O.B.: "Well control evaluation as an integral part of well design." IADC Well Control Conference Europe, Amsterdam 9-10 April 2008.

19. Rygg, O.B.: "The necessity of modelling in contingency planning and emergency well control response." IADC International Well Control Conference & Exhibition, Singapore 8-9 November 2005.
20. Reed, M., Emilsen, M. H., Hetland, B. Johansen, Ø, Buffington, S., "Numerical Model for Estimation of Pipeline Oil Spill Volumes", 2003 International Oil Spill Conference, Vancouver, British Colombia, Canada
21. Rygg, O, Emilsen, M. H., "Analysis Of The Hazardous Consequences Of Pipeline Ruptures", PSIG Annual Meeting, October 23-25, 2002, Portland, Oregon
22. Hartmann, R., Møllerstad, H., Bysveen, J. and Rygg, O.B. "Blowout Contingency for Deep Water High Rate Subsea Gas Wells" IADC International Deepwater Drilling Conference, Rio de Janeiro, Brazil, Nov. 2003
23. Rygg, O.B. Friedemann, J.D. and Nossen, J., "Advanced well flow model used for production, drilling and well control applications." IADC Well Control Conference for Europe, Aberdeen, May 1996
24. Rygg, O.B. and Smestad, P., "Blowout Control Hydraulics applied to Critical well Planning." IADC Well Control Conference for Europe, Stavanger, June 1994
25. Smestad, P., O.B. Rygg and J.W. Wright, "Blowout control: response, intervention and management, Part 5, Hydraulics modelling," World Oil, pp 75-80, April 1994
26. Rygg, O.B.; Smestad, P, and Wright, J.W.: "Dynamic Two-Phase Flow Simulator, a Powerful Tool for Blowout and Relief Well Kill Analysis." SPE 24578, Presented at the 67th SPE Annual Technical Conference and Exhibition, Washington DC, Oct. 1992.
27. Frode Leraand; J.W. Wright; M.B. Zachary; B.G. Thompson, "Relief-Well Planning and Drilling for a North Sea Underground Blowout", SPE Paper Number: SPE-20420-PA.
28. Bendiksen, K., Malnes, D., Moe, R. and Nuland, S.: "The Dynamic Two-Fluid Model OLGA: Theory and Application." SPE Production Engineering, May 1991.