



RECOMMENDED PRACTICE

DNV-RP-U301

Risk Management of Shale Gas Developments and Operations

JANUARY 2013

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FOREWORD

DNV is a global provider of knowledge for managing risk. Today, safe and responsible business conduct is both a license to operate and a competitive advantage. Our core competence is to identify, assess, and advise on risk management. From our leading position in certification, classification, verification, and training, we develop and apply standards and best practices. This helps our customers safely and responsibly improve their business performance. DNV is an independent organisation with dedicated risk professionals in more than 100 countries, with the purpose of safeguarding life, property and the environment.

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- *Standards*. Technical requirements.
- *Recommended Practices*. Guidance.

The Standards and Recommended Practices are offered within the following areas:

- A) Qualification, Quality and Safety Methodology
- B) Materials Technology
- C) Structures
- D) Systems
- E) Special Facilities
- F) Pipelines and Risers
- G) Asset Operation
- H) Marine Operations
- J) Cleaner Energy
- O) Subsea Systems
- U) Unconventional Oil & Gas

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CHANGES

General

This is a new document.

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1 Introduction

1.1 Objective

The overall objective of this Recommended Practice (RP) is to establish guidelines and recommendations for the processes required to protect the safety of people and the environment during all phases of shale gas field development and operations.

It is further the ambition that this document shall increase the overall awareness of risks from shale gas activities and demonstrate how to best manage these risks.

It is the intention of DNV that this Recommended Practice may serve as a reference document for independent assessment or verification.

This Recommended Practice aims at covering risk management issues which are particular for shale gas fields. It does not cover issues related to what are considered normal gas field facilities, even if such facilities are normally also used at shale gas fields.

1.2 Approach

1.2.1 Use of functional requirements

Shale gas operations are conducted at locations which may differ significantly with respect to natural environment, local communities, geological characteristics and regulatory regimes. Also, technology development will change the shale gas industry over time. It is therefore considered most appropriate to base this Recommended Practice on functional requirements that define the main principles required to manage risks instead of prescriptive requirements. These functional requirements are accompanied by detailed technical requirements where deemed necessary.

The risk management process rests on the following principles:

- specifications and functional performance requirements shall be clearly defined, quantified and documented
- the specifications shall include the functions needed to ensure an adequate safety level when combined with adequate management, design and operational processes
- threats that may impair the functional requirements shall be identified
- tailored threat identification should be carried out for novel elements where the uncertainty is most significant – e.g., by a technology qualification process – ref. DNV-RP-A203
- the relevance of individual threats shall be determined based on their risk
- risk assessments shall be used to evaluate the appropriateness of requirements and to guide decision-making
- management plans and processes shall be in place for all parts of development and operations and shall be adequate to secure fulfilment of the specified technical requirements.

1.2.2 Risk acceptance criteria

Risks within shale gas production activities shall be assessed against acceptance criteria relating to:

- personnel health and safety
- environmental impact
- societal impact.

In addition the operator should define acceptance criteria for risks to assets and production capacity.

Where relevant, the criteria shall be developed to cover risks for the operator, operator personnel and contractors, as well as, third parties and society at large. Defined criteria shall comply with company and project policies, and be specific for each of the areas above.

1.3 Structure of this Recommended Practice

[Sec.2](#) describes the intended application of the Recommended Practice, the principle of equivalence and the relationship of this Recommended Practice to other codes and standards.

[Sec.3](#) presents definitions and abbreviations used in this Recommended Practice.

[Sec.4](#) defines general recommendations to risk management, consistent with ISO 31000. Further it stipulates requirements and recommendations to the framework for shale gas activities in terms of management systems and principles applicable to shale gas management processes.

[Sec.5](#) provides recommendations on the management of health and safety issues related to shale gas fields. The predominant health and safety risks associated with shale gas activities are related to:

- potentially large numbers of wells and well pads with high density distribution and the associated

- infrastructure and logistical operations
- equipment for hydraulic fracturing which involves fracturing fluids at high pressure
- vehicle traffic
- waste management issues related to residuals handling, storage, transport, treatment, recycling, reuse and/or disposal.

[Sec.6](#) identifies and describes recommendations for the management of environmental risks. The predominant environmental risks associated with shale gas activities are related to:

- contamination of surface and groundwater
- greenhouse gas emissions (combustion gases from engines, fugitive methane, flaring, venting) and other emissions to air
- release of chemicals
- impacts/effects from dust, odours, noise and light.

[Sec.7](#) provides recommendations for the management of risk aspects associated with the wells. The main risks are related to:

- flow of gas or liquids between the production zone and groundwater aquifers
- contamination of aquifers during drilling operations.

[Sec.8](#) addresses the management of risks related to the acquisition, transport, storage and use of water and energy.

[Sec.9](#) provides recommendations for the management of risks associated with development and use of new and existing infrastructure. Further it addresses risks associated with logistics challenges.

[Sec.10](#) provides a set of recommendations on stakeholder communication and public engagement. The lack of public awareness of the threats and opportunities of shale gas, including the lack of factual and objective information, may constitute an important business risk to a project.

[Sec.11](#) provides a set of recommendations on the permitting process. The main challenges related to permitting of shale gas projects are:

- public engagement/acceptance influencing the permitting process
- communication with regulators and stakeholders during the permitting process
- several levels of authority bodies (national, regional and local) which may have different viewpoints on shale gas
- absence of legislation for shale gas specific aspects
- risk of litigation with landowners, organisations and members of the public.

[App.A](#) exhibits the DNV Risk Management Framework which provides guidance for development of a company or operations specific risk management framework consistent with ISO 31000.

[App.B](#) elaborates on third party risk considerations.

2 Application

2.1 Use and users of this Recommended Practice

Processes, principles, methods and tools described in this Recommended Practice may be applied as a basis for, e.g.:

- defining best practice risk management
- tendering (through specification and/or definition of required processes and/or indicated risk levels)
- as a contract reference, providing descriptions/specifications for the risk management process
- as a reference for independent assessment and verification
- as a reference for communication with stakeholders
- as a reference for development of shale gas specific regulations.

Anticipated users of this document include:

- shale gas exploration and production operators and their contractors
- regulators
- independent verifiers.

In addition the document could be used as guidance by; e.g.:

- investors and other financial stakeholders
- insurance companies
- trade groups/associations

- academia and research organisations
- other involved parties.

The main parts of this Recommended Practice will normally be used by the operator during planning of a new shale gas development, as well as, for design of the main facilities for exploration, drilling, production and support. It is recommended that the results of the risk management considerations during planning and design are transferred to procedures and checklists for simplified risk management in the more repetitive stages of drilling and production operations.

In order for the user to state that this Recommended Practice has been complied with, at a minimum, all requirements formulated in the verbal form “shall” must be complied with. Such compliance shall be documented in a verifiable manner. The operator shall, through his risk assessments, identify those activities and processes, materials, equipment and systems which are to be subjected to verification by DNV or another independent verifier/assessor.

The exploration phase will typically involve fewer and/or less rigorous processes and engage fewer or down-scaled systems, equipment, infrastructure etc. The provisions of this Recommended Practice may be adapted to the processes and systems, equipment, infrastructure etc. encompassed during this phase accordingly and shall apply as far as they are relevant and applicable.

The user is encouraged to organize the necessary documentation to demonstrate conformance to the various sections of this RP as stand-alone documents or more integrated packages. In any case, analyses, assessments, studies, plans etc. may be included in a variety of formats that work within the existing framework of an organization’s overall management system.

2.2 Alternative methods, the principle of equivalence

This document describes a practice recommended by DNV. This should not inhibit use of other alternative approaches meeting the overall ambitions and objectives.

Alternatives to detailed requirements in this Recommended Practice may be acceptable when the overall safety and reliability level is documented and found to be equivalent or better than that of this RP. This also applies to requirements formulated in the verbal form “shall”.

2.3 Regulatory requirements

Regulatory requirements are in the context of this Recommended Practice defined as requirements stipulated in, or derived from, legislative instruments relevant to shale gas activities, such as;

- internationally binding conventions/directives
- federal/national acts
- federal/national/state/province/local regulations
- terms and conditions of licenses and permits.

Regulatory requirements represent the minimum requirements to be complied with.

Requirements stipulated in, or derived from the processes stipulated in, this Recommended Practice may be stricter or additional to regulatory requirements.

In the case of contradiction or conflict between regulatory requirements and requirements of this Recommended Practice, the former shall prevail.

2.4 Relationship to other codes and standards

There are a number of design codes covering systems, components, equipment and materials used in shale gas production, and these should be sought out and used where needed.

It should be noted that the use of risk based principles acknowledges explicitly that it may be cost-effective to allow some systems to fail as long as the consequence or likelihood of that failure is sufficiently low.

2.5 References

The following standards/guidelines include provisions which, through reference in this Recommended Practice, constitute provisions of this DNV Recommended Practice. This shall be limited to the parts of the referenced standards/guidelines which are relevant and applicable in the context of this Recommended Practice. The latest issue of the referenced standards shall be used unless otherwise agreed. Other recognised standards/guidelines may be used provided it can be demonstrated that they meet or exceed the requirements of the standards referenced below. This provision shall be seen in conjunction with the provisions of [2.1](#) and [2.2](#).

API Spec 5B	Specification for Threading, Gauging and Thread Inspection of Casing, Tubing, and Line Pipe Threads
API Spec 5CT	Specification for Casing and Tubing
API Spec 10A	Specification for Cements and Materials for Well Cementing
API RP 10B-2	Recommended Practice for Testing Well Cements

API RP 10D-2	Recommended Practice for Centralizer Placement and Stop Collar Testing
API TR 10TR4	Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations
EN 16001	Energy Management systems - Requirements with guidance for use
ISO 9001	Quality Management systems – Requirements
ISO 31000	Risk Management – Principles and guidelines
ISO 50001	Energy Management systems - Requirements with guidance for use

The following standards provide guidance:

API HF1	Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines
API HF2	Water Management Associated with Hydraulic Fracturing
API HF3	Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing
API RP 90	Annular Casing Pressure Management
API STANDARD	
65-Part 2	Isolating Potential Flow Zones During Well Construction
API TR 10TR1	Cement Sheath Evaluation
CCPS	Guidelines for Risk Based Process Safety (20 elements)
ISO 14001	Environmental Management Systems – Requirements with guidance for use
DNV-RP-A203	Qualification of New Technology
DNV-RP-J203	Geological Storage of Carbon Dioxide
ISO 15156-1	Materials for use in H ₂ S-containing environments in oil and gas production - Part 1: General principles for selection of cracking-resistant materials
ISO 19011	Guidelines for auditing management systems
ISO 28000	Specification for security management systems for the supply chain
ISO 55000 series	Asset Management
ISRS	International Safety and Sustainability Rating System
OHSAS 18001	Occupational Health and Safety Systems – Requirements
OSHA 1910.119	Process Safety Management of Highly Hazardous Chemicals
PAS 55	Specification for the optimized management of physical assets.

3 Definitions

3.1 Definitions

<i>Term</i>	<i>Definition</i>
<i>Abandoned well</i>	A well that is no longer in use, whether dry, inoperable, or no longer productive, having exposed permeable zones, fluids and pressures isolated from surface and from lower pressured zones. An abandoned well may be permanently or temporarily abandoned.
<i>ALARP</i>	“As low as reasonably practicable” To reduce a risk to a level which is as low as reasonably practicable involves balancing reduction in risk against the time, trouble, difficulty and cost of achieving it. This level represents the point, objectively assessed, at which the time, trouble, difficulty and cost of further reduction measures become unreasonably disproportionate to the additional risk reduction obtained.
<i>BAT</i>	“Best Available Technique/Best Available Technology” BAT is defined as the latest stage of development (state of the art) of processes, of facilities or of methods of operation which indicate the practical suitability of a particular measure for limiting discharges, emissions and waste. Available techniques shall be compared based on their environmental performance over the entire life cycle, on the financial implications of each technique and on their technical applicability to the project. The BAT selection process shall be documented through a BAT assessment report.
<i>BEP</i>	“Best Environmental Practice” BEP is defined as the application of the most appropriate combination of environmental control measures and strategies. For activities likely to have significant impacts on the environment, environmental practices shall be compared and the best option should be selected. The BEP selection process shall be documented through a BEP assessment report.
<i>BLP</i>	“Best Logistics Practice” BLP is defined as the application of the most appropriate combination of logistics control measures and strategies. The BLP selection process shall be documented through a BLP assessment report.
<i>Blowout</i>	An uncontrolled flow of reservoir fluids into the wellbore, surrounding rock / soil or to the surface.
<i>Disposal well / Injection well</i>	A well used to inject fluids into an underground formation either for enhanced recovery or disposal.
<i>Gathering line / flowline</i>	In-field pipeline upstream of the processing plant/modules.
<i>Groundwater</i>	Subsurface freshwater (potable water) aquifers and any other legally protected/protectable subsurface water resources.
<i>Hazmat</i>	Hazardous material.
<i>Hydraulic fracturing</i>	The process of injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing fractures through which oil or natural gas can flow to the wellbore.
<i>Hydraulic fracturing fluid</i>	A water or oil based fluid that typically contains a mixture of proppant (often sand) and additives used to hydraulically induce cracks in the target formation.
<i>Invasive species</i>	Any species, including its seeds, eggs, spores, or other biological material capable of propagating that species, that is not native to the ecosystem.
<i>Naturally occurring radioactive material (NORM)</i>	Low-level, radioactive material that naturally exists in native materials.
<i>Perforations</i>	The holes created between the casing and liner into the reservoir (subsurface hydrocarbon bearing formation). These holes create the mechanism by which fluid can flow from the reservoir to the inside of the casing, through which oil or gas is produced.
<i>Permeability</i>	A rock’s capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.
<i>Play</i>	A set of oil or gas accumulations sharing similar geologic and geographic properties, such as source rock, hydrocarbon type, and migration pathways.
<i>Produced water</i>	Any of the many types of water produced from oil and gas wells.
<i>Propping agents/ proppant</i>	Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.
<i>Restoration</i>	Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves re-gardening, replacement of topsoil, re-vegetation, and other work necessary to restore the area.
<i>Reservoir</i>	A subsurface hydrocarbon bearing formation.

<i>Risk</i>	Effect of uncertainty on objectives: <ul style="list-style-type: none"> — An effect is a deviation from the expected – positive and/or negative. — Objectives can have different aspects (such as financial, health and safety, and environmental goals) and can apply at different levels (such as strategic, organization-wide, project, product and process). — Risk is often characterized by reference to potential events and consequences of an event, or a combination of these. — Risk is often expressed in terms of a combination of the consequences of an event (including changes in circumstances) and the associated likelihood of occurrence.
	Further definitions relating to risk may be found in ISO 31000.
<i>Seepage</i>	The slow escape of gas or liquid out of the ground.
<i>Shale gas</i>	Natural gas produced from low permeability shale formations.
<i>Stakeholder</i>	A person or organisation which can affect, be affected by, or perceive themselves to be affected by a decision or activity.
<i>Stimulation</i>	Any of several processes used to enhance near wellbore permeability and reservoir permeability, including hydraulic fracturing.
<i>Total dissolved solids (TDS)</i>	The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.
<i>Transmission line</i>	The pipeline downstream of the processing plant, in turn connecting/delivering/feeding gas to a regional/national grid.
<i>Verification</i>	An examination to confirm that an activity, a product or a service is in accordance with specified requirements.
<i>Water quality</i>	The chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.
<i>Watershed</i>	All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.
<i>Well Pad</i>	A site constructed, prepared, levelled, or cleared in order to perform the activities and stage the equipment necessary to drill one or more natural gas exploratory or production wells.

3.2 Abbreviations

ALARP	As low as reasonably practicable
BAT	Best Available Technique/Best Available Technology
BEP	Best Environmental Practice
BLP	Best Logistics Practice
BOP	Blow-out Preventer
EBS	Environmental Baseline Study/Survey
EIA	Environmental Impact Assessment
EMS	Environmental Management System
ES	Environmental Statement
GHG	Greenhouse Gas
HSE	Health, Safety and Environment
NGO	Non-governmental Organisation
PBT	Persistent, Bio-accumulative and Toxic
POS	Post Operations Survey
PPE	Personal Protective Equipment
QA	Quality Assurance
QC	Quality Control
QRA	Quantitative Risk Assessment
RP	Recommended Practice

3.3 Verbal forms

For verification of compliance with this RP, the following definitions of the verbal forms, shall, should and may are applied:

<i>Shall</i>	Indicates a mandatory requirement to be followed for fulfilment or compliance with this Recommended Practice.
<i>Should</i>	Indicates a recommendation that a certain course of action is preferred.
<i>May</i>	Indicates permission, or an opinion, which is permitted as a part of conformance with this Recommended Practice.

4 Risk Management Principles

4.1 Introduction

This section defines the basic recommended practices for systems for the risk management of shale gas activities. The risk management process and procedures shall be consistent with the ISO 31000 or equivalent process and take appropriate account of specific considerations for shale gas activities.

The term risk management is in this Recommended Practice applied in the more narrow meaning as the management processes required to protect the safety of people, the environment and assets against harm.

4.1.1 Management system

A documented management system shall be in place which covers all activities of a shale gas development and operation undertaking, both on-site and off-site. It is recommended that the management system be an integrated system covering quality, health, safety and the environment. In addition, other relevant management process groups may be included.

The management system shall be consistent with the following, or equivalent, standard:

— ISO 9001 Quality management systems – Requirements.

The management system should be consistent with the following, or equivalent, standards:

— ISO 14001 Environmental management systems – Requirements with guidance for use
— OHSAS 18001 Occupational health and safety systems – Requirements.

The management system should be consistent with either of the following, or equivalent, standards:

— ISO 50001 Energy management systems - Requirements with guidance for use
— EN 16001 Energy management systems - Requirements with guidance for use.

The management system shall require a risk management plan to be developed which describes, communicates and documents the objectives, responsibilities and activities specified for assessing and maintaining the risk at an acceptable level.

The management system shall be consistent with the following, or equivalent, standard:

— ISO 31000 Risk management – Principles and guidelines.

The management system shall include a process for managing major accident risk, e.g., safety barrier management, where safety barriers are identified and performance standards are established for the barriers before start up, and subsequently monitored during the operations phase.

The following standard provides guidance on risk management and tools to audit health, safety and environmental risks and risks related to major accidents:

— ISRS International Safety and Sustainability Rating System.

For management of process related risks the following standards may be applied:

— CCPS Guidelines for Risk Based Process Safety (20 elements)
— OSHA 1910.119 Process Safety Management of Highly Hazardous Chemicals.

[App.A](#) exhibits an example of a risk management framework consistent with the ISO 31000 series.

The following standards provide guidance on asset management:

— PAS 55 Specification for the optimized management of physical assets
— ISO 55000 series on Asset Management (In development).

The management system shall further cover security aspects regarding e.g., field and pad installations/facilities, pipelines etc. The following standard provides guidance on security management systems:

— ISO 28000 Specification for security management systems for the supply chain.

The management system shall include processes and procedures to ensure proper management of interfaces between organisations across the supply and/or value chain.

All organisations across the supply and/or value chain shall be required to adhere to relevant parts of the operator's management system.

All personnel involved in the shale gas activities shall be thoroughly introduced and have access to relevant parts of the organisation's management system.

4.1.2 Risk identification and assessment

Risk assessment is used for decision support. The decisions being made in the different phases of a project vary, and the need for decision support varies accordingly.

Therefore the risk identification and subsequent risk assessment process should be tailored to the relevant stage of development for a project, reflecting the decisions to be made and the level of available detailed information. In particular, the exploration phase will typically involve fewer or less rigorous processes and engage fewer or down-scaled systems, equipment, infrastructure etc. The provisions of this Recommended Practice may be adapted to the processes and systems, equipment, infrastructure etc. encompassed during this phase accordingly and shall apply as far as they are relevant and applicable.

In the early phase of the planning when the key issue is to select a business model and technical concept, the main risk activities will be to establish risk criteria and safety targets as well as to demonstrate the absence of “showstoppers”. This may require qualitative approaches. At this stage of the development detailed Quantitative Risk Analyses (QRA’s) will have limited value as no detailed information to describe the facilities will be available as input.

In the next phase the risk assessment needs to provide quantitative risk information related to the land planning in support of the permitting process.

In later project phases, where key issues will be the design of mitigation measures, more detailed analyses will be appropriate to provide a proper basis for decisions.

This varying level of detail in the risk assessment process is illustrated in Table 4-1.

Table 4-1 Guidance for acquisition and assessment of risk related information in different project phases or well pad phases, as applicable			
<i>Project Phase</i>	<i>Needed risk related information</i>	<i>Key decisions based on risk assessment</i>	<i>Method of risk assessment</i>
Concept definition and exploration	<ul style="list-style-type: none"> — Identify stakeholders — Initial input to the permitting process (demonstrate absence of showstoppers) — First estimate of the risk criteria 	<ul style="list-style-type: none"> — Select site — Identify and decide risk criteria — Select design criteria — Decide to continue well pad development 	<ul style="list-style-type: none"> — HAZID — Consequence analyses of major accident scenarios — Prepare risk criteria — Risk communication to government parties
Development of basic design of well pad	<ul style="list-style-type: none"> — Focus areas for the design process, i.e., results from HAZID & Consequence analyses — Estimate of the risk level of design options — Basis for selection of an optimised basic design 	<ul style="list-style-type: none"> — Optimisation of the design in terms of safety by comparison of options — Confirm concept selection — Authority permit — Decide to start detailed design 	<ul style="list-style-type: none"> — Qualitative analysis (Risk Matrix) — HAZOPs — QRA — Detailed consequence assessment — Fire/explosion analysis — Risk communication to government parties and other stakeholders
Detail design of well pad	<ul style="list-style-type: none"> — Performance standards for components and systems — Issues to be addressed in the design identified in HAZOP findings incl. SIL requirements — Specifications for structures and equipment 	<ul style="list-style-type: none"> — Selection of equipment, solutions and operational procedures — Detailed design 	<ul style="list-style-type: none"> — Detailed QRA — Detailed HAZOPs — Vendor HAZOPs — Evacuation analysis
Commissioning and start-up of well pad	<ul style="list-style-type: none"> — Final results from risk assessment — Confirmation of acceptance according to regulations 	<ul style="list-style-type: none"> — Approve the design — Approve decision to start-up 	<ul style="list-style-type: none"> — Completion of risk studies and verification schemes — Commissioning of safety systems — Risk communication to government parties and other stakeholders

4.2 Specific recommendations on risk management

4.2.1 Operator’s objectives

The operator shall define objectives for the operations in question that are aligned with organisational goals. Whereas goals may be high level statements that provide an overall context for what the operator is trying to achieve, the objectives shall describe the specific, tangible results that a given operation will deliver, both to the operator and the community in which the operation takes place.

The operator’s objectives shall be specific, measurable, achievable, realistic and time limited.

The operator’s objectives shall reflect the operator’s corporate social responsibility objectives.

4.2.2 Scope

Table 4-2 describes internal and external factors that an operator shall take into account when defining the scope of the risk management process.

Environment, resources, infrastructure and subsurface developments	1	Natural environment: meteorology, surface environment (ecology, wildlife, botanic, parks and reserves, etc.), biosphere, hydrosphere, and geosphere (including geology, hydrogeology, geochemistry, tectonics and seismicity).
	2	Resources: groundwater, hydrocarbon and mineral reserves, coal seams, geothermal energy.
	3	Infrastructure and facilities: buildings, transportation corridors (roads, railroads, pipelines, etc.), power distribution lines, oil and gas production and processing facilities, wells, water reservoirs.
	4	Subsurface developments: hydrocarbon production, mineral extraction, mining, waste disposal, natural gas storage, acid gas disposal, geothermal energy conversion.
Social, cultural, political and economical	5	Demographic, historical and cultural factors that can influence how the shale gas activities will affect or be viewed by stakeholders.
	6	Political elements and trends that may influence the perception and/or financing of a production site.
	7	Geographic and temporal economic factors, including possible effects of the project upon the local economy.
Legal, regulatory, and industry practice	8	Relevant directives, acts and regulations applicable to exploration and production sites and any active initiatives to introduce new or modify existing directives, acts or regulations.
	9	Relevant codes, standards, protocols and guidelines that may serve to guide risk management and facilitate demonstration of compliance with directives, acts and regulations.
	10	Manuals that document current industry practice and guide cost-effective implementation of exploration and production technology and in accordance with best industry practice.
Operator resources	11	Economic ownership, contributions and liabilities for each component in the installations.
	12	Operator responsibility and authority limitations, including limits to resources and commitment to risk management.
	13	Experience of the organisations involved in the project to address risks through the development and implementation of a comprehensive risk management plan.
	14	Available resources, capacities and capabilities for performing isolated functions with respect to the exploration and production site and for integration across all project components and in the total project.

4.2.3 Consequence categories

Risks may be usefully grouped into categories according to the nature of their consequences. The consequence categories for risk management of a shale gas site shall include the following:

- human health and safety
- environmental resources and values
- other impact on local community including infrastructure
- other impact from use of land, water and other resources
- wells and gas containment
- regulatory compliance.

The consequence categories may also include the following:

- reputation and relations to community and other stakeholders
- production of gas
- cost and schedule.

The operator may apply additional categories as appropriate.

Stakeholder views and risk perceptions shall be adequately understood and appropriately considered when specifying consequence categories. To this end, stakeholders’ values, assumptions, capabilities, and concerns

that may impact decisions based on risk considerations or hinder the achievement of objectives shall be identified and recorded. Conflicting positions shall be analysed and decisions underpinned.

4.2.4 Risk identification and assessment

The risk identification and assessment processes shall be tailored to the relevant stage of development for the shale gas activity, for example exploration, development, drilling or commissioning.

4.2.5 Use of risk management information in decision-making

Means shall be in place to ensure that relevant information about the conditions for safe operations is available and taken into consideration in decision-making. Assessments of the acceptability of planned operations and designs with respect to risks shall be escalated to the appropriate level in the organization at the appropriate time and under the appropriate conditions, e.g., at the right time in cases of failures and emergencies.

The risk management work shall be recorded for future reference by decision makers. These recordings shall also include assumptions and conditions defined for safe operations of the facilities as well as the methods used in assessing the acceptability of risks. In future assessments of risk it shall be ensured that these recordings are taken into account and that new assumptions, conditions and methods applied are consistent with those which are applicable to the systems and operations considered.

Means shall be implemented to ensure that these requirements are feasible throughout the lifetime of the facilities and for all relevant decision makers of the operator and its contractors.

4.2.6 Personnel competence

Personnel shall be competent, adequately trained and informed to undertake the tasks and responsibilities assigned to them.

In particular, personnel shall be knowledgeable and have adequate competence for maintaining conditions for operations, including management of the means to manage risks such as barriers for preventing accidents and minimizing their consequences.

Personnel performance should be monitored with a view to identifying their professional development needs.

4.2.7 Baseline surveys

Baseline surveys shall be used to determine the condition of an item prior to commencement of any activity which may alter the condition of that item. The baseline surveys may take the form of assessment and measurement. See also [6.5.1](#), [9.2.6](#) and [9.3.6](#) for more specific recommendations on baseline surveys.

The baseline values enable the operator to monitor the development of risk elements and also provide a platform for the resolution of dispute.

The risk assessment/ranking should provide input to identifying the items to be surveyed. The planned baseline surveys should take into consideration the expected variations for the items to be considered, e.g., from one site to another or for different depths or over time, etc. Baseline surveys should be designed in such way that such variations are adequately captured.

4.2.8 Emergency preparedness

There shall be plans, procedures and equipment for dealing with relevant emergencies connected to the shale gas activities. The plans shall address topics such as responsibilities, response actions, communication and training. The adequacy of the emergency preparedness is the responsibility of the operator. The plans, procedures and equipment should be co-ordinated with what is available from the communities and others.

The emergency plans shall consider the needs for taking care of personnel, the environment and material assets which could be affected by the emergency.

The emergency preparedness shall, at a minimum, cover the possibility of the following events:

- leaks from the well to the surface or to groundwater aquifers
- releases of gas or hydrocarbon liquids from the facilities
- gas or hydrocarbon leaks from pipelines and flowlines
- fire at the facilities and in the vicinity of the facilities, including e.g., forest fires
- natural disasters, e.g., flooding, earthquakes, tornadoes, hurricanes
- accidental releases of chemicals or water with chemicals or produced water
- well spills on site from storage or transfer (e.g., chemicals, flowback water, condensate)
- releases from vehicles during transportation by road or rail.

The need for appropriate response and communication equipment shall be assessed as part of the emergency preparedness plan. Regular maintenance and suitable storage needs to be provided to ensure equipment is kept in good condition.

Practices shall be organised with employees on site and with contractors to ensure that personnel are familiar with the emergency preparedness plans, and know how to properly use the response equipment. To the greatest extent possible, these practices should also include support from communities and others.

After any incident or accident, the performance of the emergency response shall be assessed and corrective actions shall be implemented when required. Additionally, the environmental impacts of the incident or accident shall be assessed, and appropriate remediation measures shall be implemented when required.

4.3 Quality assurance, quality control

The risk assessments will provide input to the QA programme, especially the identification of QA focus areas. QA and QC activities shall be planned, executed and documented throughout the lifetime of the operations.

In addition to the QA programme, the QC activities are governed by the requirements of the codes/standards identified for use in the activities.

QA/QC activities shall be performed by personnel possessing the necessary competence and who are organisationally independent of the units having produced the objects to be inspected.

4.4 Transparency

Transparency builds trust among stakeholders and is strongly correlated to the level of public acceptance.

The operator should endeavour to meet information and knowledge sharing requests from relevant stakeholder groups. Recommendations for communication with stakeholders, including the public, are provided in [Sec.10](#).

4.5 Audits

Audits shall be used to determine the extent to which the management system requirements are fulfilled. Audit findings are used to assess the effectiveness of the management system and to identify opportunities for improvement.

In addition to internal (first party) audits, the operating organisation shall perform second party audits on organisations involved in its shale gas activities, across the entire supply/value chain. The (annual) audit plan, i.e., the selection of organisations/organisational units to be audited, may be based on a risk ranking process.

In addition to planned audits, so-called “fact-finding” audits may be instigated in response to undesirable events. Ordinary auditing techniques may then be supplemented by e.g., root-cause analysis.

The following standard provides guidance on auditing:

- ISO 19011 Guidelines for auditing management systems.

5 Health and Safety Risk Management

5.1 Introduction

This section defines the recommended practices for management of the risk to health and human safety in shale gas activities. Described are recommendations for processes and tools that shall be considered for shale gas activities to ensure that health and safety issues are adequately addressed.

Health and safety risks associated with shale gas activities are similar to the risks found in other parts of the oil and gas industry. For the management of such risks there are well established regulatory requirements, design standards, controls, processes and risk management principles for the protection of health and safety.

The main characteristics of shale gas activities which distinguish the potential health and safety issues from those faced by conventional oil and gas exploration and production may include:

- a large number of wells and well pads with high density distribution
- associated high density of infrastructure (e.g., flowlines and pipelines) sometimes in close proximity to other stakeholders including local communities
- hydraulic fracturing which involves injecting fracturing fluids with chemicals at high pressure into the target formation ([Sec.7](#))
- potential of low level seismic activity attributed to the activity of the hydraulic fracturing process
- logistics with needs for high transportation volumes by road, increasing traffic levels in local communities ([Sec.9](#)).

All shale gas operations will need to consider the principles of risk management and ALARP to ensure that health and safety issues relating to all stakeholders are thoroughly addressed. This activity should build on, at a minimum, complying with all applicable requirements and adopting industry good practice related to the management of health and safety issues and risks on site during the lifecycle of the shale gas activity.

5.2 Planning and implementation

Health and human safety shall be a fundamental part of the planning and implementation of shale gas activities and included in the risk management plan. This shall be conducted in line with the risk management principles and steps taken to reduce the impact on health and safety to be as low as reasonably practicable (ALARP), as outlined in [Sec.4](#). The risk management process shall take into account the hazards identified and associated with each phase and activity of shale gas exploration and production, from design, construction and production

operation, to abandonment and restoration of land.

An approach should be applied throughout the shale gas activity life cycle which demonstrates in a documented form that the facility operator has identified and assessed all major safety hazards. It should also be shown how the risks are managed to achieve an acceptable level of safety. The key topics for inclusion in this approach should include:

- description of the installation and its operation
- a safety risk assessment
- identification of risk reduction measures
- the health and safety parts of the risk management system
- emergency preparedness and response for protecting health and safety
- the means for audit and review
- demonstration of operator and workforce involvement.

It is important that a robust risk management regime using recognised techniques for assessment and mitigation of hazards is applied and that the extent and sophistication of the assessment are dependent on the anticipated magnitude of the risk. These principles are outlined in ISO 31000.

In determining controls for health and safety risk mitigation the principles of “hierarchy of controls” in reducing the risks should be observed, consistent with the principles detailed in standards such as OHSAS 18001. The controls should be selected according to their effectiveness on reducing the risk. The prioritization of controls should be according to the following list (by descending priority):

- elimination
- substitution
- engineering controls and operational procedures
- signage/warnings and/or administration controls
- personal protective equipment.

All findings from the risk assessment process and controls shall be documented and should form the basis for establishing and implementing a safety management system. The safety management system shall address all stakeholders in addition to those personnel employed on site including contractors, drivers, visitors as well as other facilities, buildings and the local community.

The following sections outline the considerations that need to be taken into account to ensure that the health and safety of personnel are properly managed.

5.3 Design

Minimizing environmental, health and safety risks during facility planning, selection of well pad components, including drilling equipment and control systems, and the layout of the well pads is the primary design goal of this Recommended Practice. The use of Best Available Technology (BAT) to engineer out environmental, health and safety risks identified through various risk assessments is essential when the principles of ALARP and cost benefit analysis suggests this is feasible alternative.

In planning shale gas activities, lessons learnt and past experiences in hydrocarbon exploration and shale gas should be taken into account. When health and safety risks cannot be engineered out, administrative processes and personnel training to ensure competence is established shall be implemented to ensure risk mitigation is addressed.

5.4 Infrastructure and logistics

Shale gas development and operations involve considerable infrastructure development and logistical operations. [Sec.9](#) of this Recommended Practice provides details on mitigating these risks.

Careful management is required on some well pads where there may be a high number of wells, when in cases where a high number of well pads are required to extract gas in a given area, and supporting infrastructure is potentially close to other stakeholders, such as residential areas.

The infrastructure footprint and logistical operations shall be minimized to reduce potential risks to health and safety of personnel on site and other stakeholders in the vicinity. This shall be balanced against the increase in risk levels caused by a complicated and condensed site arrangement. Mitigating impacts on health and safety should include:

- implementing effective traffic and site management controls to minimize the impact of traffic on site and public highways
- the management of security and access to sites including well pads, pipelines, processing facilities etc.
- contractor and visitor management
- the potential impact on other stakeholders during normal, abnormal and emergency situations.

5.5 Operations

Effective risk management processes shall be implemented that ensure that health and safety issues are

mitigated and controlled. This shall include management system elements discussed earlier to ensure continual improvement in health and safety performance. These shall ensure that:

- compliance is maintained with standards and guidelines which the organisation is required to meet
- procedures and controls are established to ensure the operating processes continue in a safe manner
- near miss, accident and incident reporting and follow up actions are established
- occupational health and safety is monitored and managed
- a training needs analysis is conducted to identify requirements and frequency of training and that an associated plan is implemented and re-training is conducted at a pre-determined frequency or when identified as required after near misses, accidents or other events.

Operations shall be in accordance with design and design assumptions.

5.5.1 Well operations

During well operations requiring high pressures to inject fluids into the well, there are a number of potential health and safety issues posing risks to operators and personnel within the vicinity including:

- degradation of cement barriers
- the potential for high pressure failures of surface equipment during drilling and hydraulic fracturing, including flowback
- the potential release of methane during the flowback operation
- other potential releases such as hydrogen sulphide and fracturing fluids.

Risk mitigation is mainly controlled through the design, construction and approval of equipment to standards capable of withstanding high pressure and liquid flow rates that the equipment is exposed to. Design controls are addressed in [Sec.7](#). Selection of equipment shall also take into account the potential for high pressure environments due to the geological characteristics of the site as well as any previous drilling records identifying risks related to the drill location.

The risk of equipment failure causing personal injury increases due to the high pressures and flow rates. Therefore, during hydraulic fracturing operations, personnel in close vicinity to the wellhead and associated equipment should be kept to a minimum and operations shall be monitored and controlled remotely from a safe distance.

Safety systems and instrumentation to detect and contain hazardous situations shall be installed, maintained and tested periodically according to recognised standards. These systems shall comprise:

- blowout preventers
- pressure and temperature shut down systems
- fire and gas (e.g., H₂S and hydrocarbons) detection systems
- fire fighting equipment.

Contingencies for failure of equipment and any subsequent releases should be included in the emergency planning and drills and include not only training of onsite personnel, but also other stakeholders, such as the use of safety briefings for visitors and contractors.

Effective monitoring shall be established to detect any leaks or releases of fluid, chemicals or gases. While the risks from the release of dangerous gasses during drilling generally are low, monitoring should be established for hydrogen sulphide, as a minimum.

Safety critical equipment, materials and systems, including safety systems, shall be identified, documented and verified to be in compliance with applied standards and/or specifications. Such verification shall be carried out by an independent verifier/assessor. The continued compliance during the operational phase(s) of the shale gas activities should be verified accordingly.

5.5.2 Seismic activity

The magnitude of seismic activity induced by shale gas exploration, as measured through geophysical seismic surveys, has been low-energetic and, to date, has had limited identified impact on health and safety.

Seismic activity induced by hydraulic fracturing shall be monitored and reduced as far as reasonably practicable, in accordance with a risk assessment which takes into account possible human health and safety risks as well as the risk of damage to, e.g., buildings and other infrastructure.

5.6 Abandonment and restoration

Controls shall be established to ensure health and safety risks are mitigated and monitored during this phase which includes:

- potential contamination of land and soil, sumps, waste, chemicals and equipment, etc.
- well abandonment ([7.10](#)), removal of processing equipment and infrastructure and logistical equipment ([9.3.5](#)) (roads, pipelines etc.)
- disposal/recycling of material and equipment

— site and public highways, traffic and use of decommissioning equipment.

Health and safety risks post-closure shall be managed by the responsible party until the liability period expires.

5.7 General health and safety risk considerations

5.7.1 Competence and awareness

Personnel working on shale gas sites shall be empowered with knowledge about health and safety risks, procedures, emergency preparedness and other relevant elements of the health and safety management system. All personnel with the potential to be exposed to health and safety risks shall be sufficiently informed, understand the processes and rules to follow to ensure their own personal safety and those that might be impacted during their work/time on site is maintained. The use of safety briefs is encouraged to improve the competence of workers in managing and mitigating health and safety risks on site.

5.7.2 Training

Health and safety training for personnel on site, visitors and contractors shall be established based on training needs analysis, level of risk and requirements for knowledge and competence. Training and re-training requirements and time frames should be established and modified based on site experience, accidents and incidents.

5.7.3 Emergency preparedness

An emergency plan shall be developed that addresses the identified hazards and risk levels to the health and safety of those potentially affected by any incident connected to the shale gas activities. This shall also include third parties, e.g., neighbours.

This shall include information to and consultation with other stakeholders which could be exposed to the consequences of events of the shale gas activities, e.g., the local community and authorities, regulators, hospitals, fire brigades, police, ambulance services, evacuation helicopters etc. Emergency preparedness shall be subject to periodical drills to ensure contingencies are in place in the event of an emergency situation.

Where drill sites are operating in areas where drinking water is extracted either from surface or groundwater it is suggested that emergency plans include liaison with the local water supplier to ensure that they have a maximum amount of time to consider and react to any implications that may affect the security of public water supply.

Other recommendations for emergency preparedness are described in [4.2.8](#).

5.7.4 Chemicals

It is essential to understand the properties of the chemicals and additives and their potential impact on health and safety and take mitigating precautions to avoid adverse health and safety effects.

Potential impacts on health and safety during the use, storage and disposal of chemicals should be reduced as much as reasonably practicable. Where possible, more benign chemical alternatives from a health, safety and environmental point of view should substitute for hazardous chemicals.

Where chemicals do pose a risk to the health and safety of personnel precautions should be taken to limit potential contact with the chemicals either through design and engineering or, as a last resort, where risk cannot be engineered out, appropriate personal protective equipment (PPE) should be provided which is suitable for the chemical characteristics.

Chemicals shall be clearly labelled, stored and used as per guidelines and Material Safety Data Sheets (MSDS) for each chemical and additive, and this information shall be obtained from the supplier and manufacturer, be reviewed prior to use and be readily available at the job site.

Handling of chemicals as well as emergency preparedness shall be considered as part of the training of pertinent personnel on site. Other personnel and visitors shall receive a general introduction to the risks associated with chemicals, before entering designated areas. See also [5.7.2](#).

5.7.5 Personal protective equipment

Where PPE is required, personnel shall be provided with appropriate and well-fitting PPE to the required standard and the equipment be subjected to testing as per the manufacturer's and organisational requirements. Suitable storage needs to be provided to ensure PPE is kept in good condition and free of contamination and its use and maintenance form part of operator provided training.

Personnel shall be equipped with dosimeters when there is a risk of being exposed to harmful gases (e.g., H₂S), including low levels of O₂, or radiation.

The need for medical assessment of the ability of individuals to wear and work with PPE shall be evaluated.

5.7.6 Naturally Occurring Radioactive Materials (NORM)

Shales may contain naturally occurring radioactive materials (NORM) that can be brought to the surface

through cuttings, flowback fluid, produced brine or accumulated as scale on pipes and tanks. Typically concentrations have been considered too low to be a health risk. However, if it becomes concentrated, such as on work equipment, this risk of exposure for workers will increase.

Field surveys should be conducted of potentially contaminated rock cuttings and cores (6.5) to assess the potential for exposure to radioactivity on health. This shall include the three most common types of radiation: alpha particles, beta particles and gamma rays. Risks relating to NORM contaminated downhole and surface equipment should also be considered.

Potential exposure to radioactivity should be adequately monitored and mitigated. This should include both site specific activities and waste, and requirements for environmental monitoring outlined in Sec.6 of this Recommended Practice to ensure potential health risks to other stakeholders are monitored and assessed.

Where NORM is identified as a risk to workers and other personnel on site, suitable changing, washing and storage facilities should be provided to ensure potentially contaminated clothing remains on site. 6.3.4.3 contains further details on potential sources of NORM during shale gas activities and on the proper disposal of potentially NORM contaminated waste.

6 Environmental Risk Management

6.1 Introduction

This section defines the recommended practices for management of risks to the environment from shale gas activities.

Focus is on the operations in the field. Additional recommendations are provided for support activities outside the field (e.g., for transportation) when relevant.

The area of influence is defined as the area likely to be affected by shale gas activities. In this section, a distinction is made between the areas of direct and of indirect influence. The area of direct influence includes the areas where shale gas drilling and processing take place and their close vicinities (e.g., surrounding fields, habitations, rivers, lakes, subsurface drinking water resources). The areas of indirect influence include additional areas affected by pipelines, access roads, or transloading areas.

The extent of the shale gas area of influence and the limit between the direct and indirect areas depend on the characteristics of the planned activities and their surroundings (e.g., topography). A definition of this extent shall be carried out by an environmental expert at the beginning of the EIA process, (see 6.2). The direct area of influence should not be smaller than the projected footprint of the horizontal sections of the wells.

Principles stated in Sec.4 are applicable to the management of environmental risks and impacts. Environmental risks shall be managed according to the ALARP principle. For this purpose, the best available techniques and best environmental practices shall be implemented on the project, see 6.3.1.

This section is organised in four parts:

- environmental impact assessment and environmental statement, see 6.2
- environmental impacts and mitigation, see 6.3
- emergency preparedness for environmental risks, see 6.4
- environmental monitoring and reporting, see 6.5.

6.2 Environmental impact assessment and environmental statement

An Environmental Impact Assessment (EIA) shall be carried out, and subsequently be reviewed/verified by an independent assessor/verifier. The scope and scale of the EIA should be adapted to the scale and complexity of the planned activities, e.g., the EIA may consider the complete field, or may focus on parts of the field. Exploration activities may be covered by a separate EIA. The EIA process shall be initiated as soon as possible in the development project, and completed no later than during the design stage. EIAs can be based on relevant assessments and information from earlier EIA work undertaken for the same areas.

Guidance note:

The definition of Environmental Impact Assessment in this DNV Recommended Practice is consistent with the one provided by UN Department for Economic and Social Information and Policy Analysis. Reference is also made to EU Directive 85/337/EEC (the EIA Directive) and the Espoo (EIA) Convention.

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The EIA shall identify and evaluate the potential environmental risks and impacts from the existing and planned shale gas activity in its area of influence. The EIA shall examine ways of improving development selections for siting, planning, design, and implementation by preventing, minimizing, mitigating, or compensating for adverse environmental impacts and enhancing positive impacts. The EIA shall include the process of mitigating and managing adverse environmental impacts throughout the shale gas field lifetime (see 6.3).

Results from the EIA shall be presented in an Environmental Statement (ES). Information to be provided in the ES shall include at least:

- a description of the activities (locations, design and size)
- a biodiversity inventory
- the main alternatives considered by the developer and the main reasons for this choice, including results from BAT/BEP assessments (see 6.3.1)
- data required to assess the main effects of the activities on the environment (see 6.5)
- possible measures to reduce significant adverse effects (see 6.3)
- a non-technical summary of this information.

An archaeological survey may be required.

Stakeholders shall be informed about the results of the EIA, if needed, through public consultations (see also Sec.10).

6.3 Environmental impacts and mitigation

The following sections provide requirements for the prevention, minimization, and mitigation of adverse environmental impacts. As a general principle, preventive measures shall be favoured over mitigation or compensatory measures.

The applicability of the listed measures and best practices shall be evaluated and justified on a case-by-case basis. Implementation of proposed measures shall not compromise other means of risk management applied.

The main findings from the plans and evaluations required in this section should be presented as part of the ES.

6.3.1 Best available techniques and best environmental practices

The Best Available Techniques (BAT) and Best Environmental Practices (BEP) assessments shall be carried out at the concept selection and design stages. BAT and BEP should be applied to the shale gas activities for systems and processes likely to have significant impacts on the environment, under consideration of the ALARP principle.

The main findings from the BAT and BEP assessments should be presented as part of the ES (see 6.2).

6.3.2 Handling of chemicals

Chemicals are used as part of the hydraulic fracturing activities, and through other stages of the shale gas activities. Depending on the nature of the chemical products or compounds, and depending on the level of exposure, chemicals may cause harm to health and to the environment. Therefore, potential impacts from the storage, use and disposal of chemicals should be reduced as much as reasonably feasible.

The following chemical management strategies shall be implemented:

- reduce the use of chemicals as much as reasonably feasible, in particular the use of persistent, bio-cumulative and toxic (PBT), carcinogenic and mutagenic chemicals
- effectively monitor and report the quantities and type of chemicals used as part of the operations (see 6.5).

Evaluation of the type of chemicals to be used, and estimates of the quantities involved shall be included as part of the ES.

A Material Safety Data Sheet (MSDS), or a similar form, for each chemical shall be obtained from the supplier or manufacturer, be reviewed prior to use, and be readily available at the job site. The MSDS shall contain information about proper storage, hazards to the environment as well as to human health in order to enable assessment of hazards to occupational and public health, spill clean-up procedures and other information to minimize environmental impacts.

The following sections describe these recommendations in more detail.

6.3.2.1 Chemicals storage and use

All components of fracture fluids, including water, additives and proppants, shall be managed properly on site before, during, and after the fracturing process. Fracturing fluid components should all be blended into the fluids used for fracturing only when needed. Any unused products should be removed from the location. The job planning process should consider unexpected delays of the fracture operations and ensure that materials are properly managed.

The following management practices should be applied:

- store chemicals in appropriate primary containers provided with sufficient secondary and tertiary containment to collect any leak from the container with the largest volume
- while priority should be given to preventing a loss of primary containment, adequate secondary and tertiary containment shall be in place for environmental protection and safety of people in the event of a loss of primary containment of chemicals.
- ensure no environmental risk is posed in the event of loss of tertiary containment

- providing greater assurance of tertiary containment measures to prevent escape of liquids from site and threatening a major accident to the environment (e.g., construction of berm)
- a berm shall be constructed around the well pad to prevent runoff from the pad site using relevant standards
- facilitate management of integrity of storage, pipes and systems handling or using the chemicals in order to avoid releases through failures (e.g., selection of materials, inspection and maintenance)
- take all appropriate measures to avoid spills during transfer of chemicals, and provide operators with spill kits to contain and collect any spill
- install an impervious liner under the entire well pad, underlain with composite decking to prevent punctures of the liner, and ensure proper inspection and repair procedures
- avoid the use of any pit, impoundment or pond for storage or disposal of fracturing fluids, flowback water, produced water or other liquids or wastes used in, or produced by, shale gas activities
- require the well pad to be sloped so as to collect all liquids for disposal or reuse/recycling.

Prior to use, chemical additives shall remain at the well site in containers or on trucks in which they are transported and delivered. Storage time should be kept low and only the amount needed for scheduled continuous fracturing operations shall be delivered at any one time.

When the hydraulic fracturing procedure commences, the blended fracturing solution should be immediately mixed with proppant and expended.

This process shall be conducted and monitored by qualified personnel, and devices such as manual valves shall be available to provide additional controls when liquids are transferred. At drill sites lined containment and protective barriers shall be used in areas where chemicals are stored and blending takes place.

The storage containers at any given site during the short period of time between delivery and completion of continuous fracturing operations should have standardized sizes, designs and material type, and the operator shall consult appropriate specifications.

Spill prevention and storm water pollution prevention measures shall be taken into consideration. The operator shall provide secondary and tertiary containment around:

- all chemical additive staging areas and fuelling tanks
- sites for transfer of fuel and other fluids
- piping for fluids
- drip pads or drip pans.

6.3.2.2 Chemicals disclosure

Chemicals and additives used during fracturing operations shall be disclosed to stakeholders, including at a minimum relevant authorities. The operator shall disclose the compositional information including:

- chemical constituent names
- chemical constituent percentage by weight information
- separate lists of mixtures and unique compounds
- composition information of all unique compounds
- associated properties of the chemicals – as needed to manage risks to health and the environment (e.g., flammability, toxicity).

See 4.4.

6.3.3 Managing environmental effects on water

The withdrawal of water shall not deteriorate conditions for life in the waterways (e.g., due to poorer flow or reduced water levels.)

Water quality shall not be caused to deteriorate through, e.g., spills during transportation of chemicals, leaks from containers and other storage at the site or failure of integrity of the wells or processing facilities due to shale gas activities and appropriate measures shall be implemented in order to prevent water contamination from normal operation and accidental events.

The following water quality preservation strategies shall be implemented:

- assess the total environmental effects of the planned water withdrawal on life in waterways
- assess the site specific groundwater contamination risk at the design stage, considering the local geology, and baselines study (see 6.5.1)
- locate the well sites and other facilities away from streams, water wells, springs, wetlands and surface water bodies – to the extent reasonably practicable
- prevent water runoff and erosion on the project site by appropriate barriers, ground covering (e.g., concrete or liner during operations, vegetation after operations)
- implement the appropriate measures to ensure the well integrity and environmentally safe hydraulic fracturing of the well (see Sec.7)
- provide all storage tanks with arrangements for secondary containment to collect potential leaks
- collect cuttings and flowback fluids in closed tank systems fitted with overflow protections

- implement the reuse and recycling of flowback fluids
- select and implement the Best Environmental Practices for the treatment and disposal of cuttings, flowback water and other wastes
- implement continuous monitoring of refuelling and fluid transfer operations
- prepare for emergencies and implement appropriate responses in case of accidental events.

The water quality within the project area of direct influence shall be monitored during and after the operations. See also [Sec.8](#) on water resource management.

6.3.4 Handling of drill cuttings and other waste

A key issue relating to development of shale gas projects is how to most safely store and dispose of materials used in and produced from the construction, drilling, hydraulic fracturing, and operation of gas wells and associated equipment. This section describes the guidance for waste management with focus on waste disposal.

Shale gas production involves use of relatively large amounts of fresh water, fracturing fluids, flowback water and produced water, chemicals and additives, as well as drilling muds and drill cuttings. Storage, transport and disposal of these materials present practical and technical challenges. The current best management approach is to minimize the amount of these materials on site, contain the materials as fully as possible, reuse or recycle them to the extent feasible, and dispose of the remainder offsite.

The operator shall provide a detailed waste management plan including the planned handling, treatment and disposal of waste. The plan shall cover all waste from the shale gas activities for the lifetime of the operations.

6.3.4.1 Waste disposal plan

A waste disposal plan shall be prepared at the feasibility and concept selection phase of the shale gas project. A major concern here is the potential for contamination to water supplies, standing water bodies, and watercourses from liquids and solids used or produced in:

- drilling operations; e.g., drill cuttings and drilling mud, flowback water and produced water
- hydraulic fracturing; e.g., chemicals, diesel fuel, foams and lubricants
- processing and other operations
- personnel quarters.

It shall be taken into account that the production waste may have picked up pollutants from the underground salts and minerals and that drill cuttings may include naturally occurring radioactive material (NORM).

Plans for disposal shall be transparent to relevant stakeholders.

The disposal plan shall provide information about:

- planned transport volumes over time
- transport method
- planned disposition of the waste
- identification of and official permits for any proposed treatment facility or disposal well planned used.

The disposal process shall be monitored and reported. Best management practices shall be applied to avoid contaminating water supplies, groundwater sources, bodies of standing water (lakes, swamps, etc.) and watercourses.

6.3.4.2 General waste disposal methods

The following applies to all waste except drill cuttings.

6.3.4.2.1 Use of regional treatment and disposal sites

The following considerations shall be applied to minimize the possible impacts of using central, regional and/or remote treatment facilities:

- site location: Pick the optimum site and access route based on the local environmental conditions
- allowance for weather: Plan for storms that prevent transportation by having back up in place; include means for temporary waste storage at the site
- site requirements: Include lighting, traffic control and emergency response (e.g., emergency shelter or trailer) at the central and/or regional disposal locations
- future demand: Ensure the central and/or regional disposal sites have enough capacity for future expansion
- proper disposal of end product after any treatment
- avoidance of spills: Transport drilling waste to the central or regional disposal location in a manner that no leaks or spills will occur
- spill response: In the event of a spill, report, respond and clean up as per all applicable requirements.

The operator shall exercise the due diligence necessary to ensure that a third party operator is managing the waste properly, that the site is adequate for handling the type and amounts of waste in question and that the required permits are in place.

6.3.4.2.2. Downhole injection

Downhole injection should only be used if the risks associated with alternative methods for waste disposal are larger than those associated with downhole injection.

Disposal of fluids through injection involves the pumping of waste solids or liquids down a well into the rock formation, where an injection zone is available. It is important to note that in some jurisdictions, disposal of fluids through injection may not be allowed or may require a permit. If this option of waste disposal is applicable the primary objective shall be the protection of underground sources of drinking water. Therefore, the operator shall demonstrate that injected fluids will remain confined in the disposal zone and isolated from fresh water aquifers. This requires an extensive surface and subsurface evaluation to address the technical issues.

Fluid disposal using injection wells may require site-specific environmental review and mitigation measures for informational purposes. When considering this option, the operator shall seek to minimize the possible impacts of downhole injection by:

- finding a zone that is geologically secure
- ensuring that there is a contingency back-up plan in place for the storage/disposal of the drilling waste, in case there are injection problems
- ensuring that the zone has appropriate characteristics including; e.g., is not hydrocarbon bearing, has an adequate rock seal above and below and that the well integrity is maintained over the planned time of use
- knowing the pressure limitations to avoid fracturing the seals
- implementing operational procedures to monitor and report performance by observation of indicators such as, e.g., injection volumes, zone pressure and injected fluid composition.

6.3.4.2.3 Sumps

Use of local in-ground sumps for fluid waste shall be avoided.

Operators may still use in-ground sumps at regional treatment plants which have the appropriate permits from relevant authorities. The major factors in assessing regional sump operations are the local environmental conditions including:

- the local terrain
- location of water bodies
- soil conditions
- on-site thermal regimes
- climate.

6.3.4.3 Disposal of drill cuttings and NORM

6.3.4.3.1 Drill cuttings

Drill cuttings are commonly considered as solid waste.

For cuttings from processes which utilise oil-based or polymer-based products special permits may be required. Likewise, if cuttings contain NORM, then additional applicable permits for disposal shall be sought.

Handling of cuttings shall include containment on-site prior to treatment (if required), transport and final disposal.

The operator may use a closed-loop tank system or a reserve pit to contain drilling fluids and cuttings. Both systems shall result in complete capture of the fluids and cuttings.

Drilling fluids and cuttings from drilling based on oil or polymers or drill cuttings containing NORM shall be handled by closed-loop tank systems.

Use of tanks in closed-loop tank systems is encouraged because this facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and provides additional insurance against environmental releases.

The design and configuration of closed-loop tank systems shall be adequate to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface. Depending on the drilling fluid utilised, appropriate types of separation equipment shall be employed within a closed-loop tank system to separate the liquids from the cuttings prior to capture within the system's containers. All transfers of drill cuttings shall occur in a designated transfer area on the well pad and should be lined.

Transportation of drill cuttings shall be adequate for the contents of the cuttings and associated fluids.

It is recommended that plastic liners used for freshwater reserve pits and pit liners from reserve pits where polymer- or oil-based drilling muds were stored shall be disposed in a properly permitted solid waste landfill. Various jurisdictions define solid wastes as hazardous or non-hazardous using different criteria and operators shall determine if any special transportation, packaging, labelling, permitting and/or testing needs to be done prior to disposal, as applicable.

6.3.4.3.2 Naturally occurring radioactive materials (NORM)

The operator should be aware that black shale as well as other formations that are often the target formations for hydraulic fracturing operations sometimes contain trace levels of naturally occurring radioactive materials (NORM). NORM may be brought to the surface through:

- cuttings
- flowback fluid
- produced brine
- scale accumulation in pipes and tanks.

Drill cuttings shall be subjected to analysis for radioactive particles and their health impacts shall be continuously assessed.

NORM contained in the discharge of fracturing fluids or production brine may be subject to discharge limitations. To determine NORM concentrations and the potential for exposure to NORM contamination in rock cuttings and cores (i.e., continuous rock samples, typically cylindrical, recovered during specialized drilling operations), the operator shall conduct field and sample surveys.

The data obtained from the above measurements which essentially indicate levels of radioactivity shall be analysed in the context of health impact.

6.3.5 Greenhouse gas emissions

Shale gas activities emit greenhouse gases (GHG) through the use of energy from fossil fuels, and during production, storage and transport activities. The emissions are mainly CO₂ from combustion and potential fugitive methane from drilling and production. In addition to the greenhouse effect, high GHG emissions are generally an indicator of low energy efficiency.

GHG emissions shall therefore be reduced as much as reasonably feasible. A GHG management plan shall be developed and implemented at the design stage to estimate the project emissions and present reduction measures to be implemented through the design and operation of the shale gas field.

GHG emissions reduction strategies shall be assessed, including but not limited to:

- use of the most energy efficient equipment and practices (see 8.3)
- implementing means to avoid venting and flaring at all stages by prevention or collection and export of hydrocarbon emissions. This includes hydrocarbon emissions from flowback water. Flaring should be preferred to venting. Safety considerations may still lead to the need for some flaring.
- implementing gas leak prevention, detection and repair measures to stop gas leaks at an early stage
- minimizing transportation of equipment, raw materials and wastes (see Sec.9)
- the use of less carbon intensive fuels (e.g., gas vs. diesel), particularly for trucks and generators
- optimizing power supply and generation facilities, e.g., by sharing power generation with other users or taking power from the regular grid.

GHG emissions shall also be monitored and reported during the operational phases (construction, drilling, completion and production) as defined by findings of the EIA and EBS (see 6.2 and 6.5). Opportunities for emissions reduction should be continuously identified and implemented.

6.3.6 Other air pollution emissions

Air pollution by use of combustion fuels, vented emissions and fugitive emissions may have several negative effects on human health and the environment. Therefore, emission of air pollutants shall be reduced as much as reasonably feasible and appropriate measures shall be implemented to ensure that residual emissions do not compromise the local air quality.

Air pollution reduction strategies shall be assessed, including, but not limited to:

- locating facilities and access roads as far as reasonably practicable away from areas where people live or stay (e.g., living areas, schools, hospitals) and from sensitive wildlife
- implementing means to avoid venting and flaring (see 6.3.5)
- minimizing emissions from vehicles and engines, e.g., by requirements to vehicles used by operator and contractors, by use of low-emission fuels or by requirements for engine design and maintenance
- optimizing the exhaust and stack heights and placement to minimize the impact on the local air quality, including vents and flare
- monitoring of the air quality during the drilling, completion and operational stages (see 6.5.2).

6.3.7 Odours

Emissions of odours from shale gas activities may occur both at the well pad and from compression stations. Depending on the odour, the person exposed, and the level of exposure, odours can cause irritation and may have negative effects on health. Therefore, odour emissions shall be reduced as much as reasonably feasible.

Odour reduction strategies shall be assessed, including, but not limited to:

- locating facilities and activities causing bad odour away from areas where people live or stay – as far as reasonably practicable
- collecting cuttings, flowback fluids and produced water in closed tank systems fitted with overflow protections, and immediately collecting any overflowing volumes
- preventing or collecting and treating emissions from vents on storage tanks (including flowback water and condensate tanks)
- limiting odour emitting operations to situations when the wind ensures sufficient dilution of odours.

Should unplanned emissions causing air pollution or odour be detected or reported, the origin of such emissions shall be investigated and emissions shall be mitigated.

6.3.8 Dust

Site construction and transport of equipment and raw material are among the potential causes for generation and emission of dust from shale gas activities, e.g., silica dust created during sand transfer. Dust can create health problems. It can also cause environmental degradation, including air and water pollution. Therefore, dust generation and emission shall be reduced as much as reasonably feasible.

Dust control strategies shall be assessed, including, but not limited to:

- preventing soil erosion by appropriate ground covering and stabilisation (e.g., concrete or liner during operations, vegetation after operations)
- installing stone tracking pad at all points of access
- preventing air currents from blowing dust by the installation of barriers (e.g., solid board fence), at right angle to prevailing wind currents, around relevant facilities
- transporting and storing sand in closed containers
- regularly cleaning vehicles and equipment being transported to and from the project site.

The use of water spraying as a dust control method should be considered with care: water should not be sprayed on areas that have been exposed, intentionally or not, to drilling and hydraulic fracturing fluids, or potentially harmful chemicals, as it may facilitate the migration of pollutants to surface and ground water bodies.

6.3.9 Noise

Energy generation, pumps, and transportation of equipment and raw material are among the potential causes for noise from shale gas activities. Depending on the level and type of noise (i.e., intermittent or continuous), noise can cause irritation and may have negative effects on human health and wildlife. Therefore, noise emission shall be reduced as much as reasonably feasible.

Noise reduction strategies shall be assessed, including but not limited to:

- locating the site of facilities and access roads as far as reasonably practicable away from areas where people live or stay and from sensitive wildlife areas
- designing and using equipment which generate less noise and using noise-reduction devices fitted on equipment
- orientating equipment to minimize noise on inhabited areas
- investigating natural noise reduction (e.g., intervening topography, vegetation) or installation of noise screens around equipment and facilities
- optimizing logistics in order to reduce the need for transports, and applying speed limits
- scheduling noise emitting operations during the day only, and communicating the schedule to relevant stakeholders, e.g., neighbours
- monitoring noise levels during the operations.

Noise modelling may be used at the design stage to assess the future noise emissions from the site and optimise the performance of the activities.

6.3.10 Invasive species

Transport of equipment and raw material may bring invasive species to the project site. Such species may spread and cause disturbance to the local ecosystems, with potential impacts on the local environment and economy (e.g., agriculture). The introduction of invasive species and their spreading shall therefore be avoided.

Invasive species control strategies shall be assessed, including but not limited to:

- assessing the presence of invasive species on site prior to operations, and after operations (see 6.5.)
- identifying, removing and adequately disposing of invasive species present on the project site
- preferring local supplies for equipment and raw materials
- inspecting equipment and raw material for the presence of invasive species prior to transport to the project site
- cleaning equipment with water prior to moving it to a new well site
- implementing screening at water intakes or sources, as relevant.

6.3.11 Light

Transport (i.e., truck or road lights), site lighting and flaring are among the potential causes for the emission of light to the surrounding environment. Excessive light, particularly during the night, can cause disturbances and may have negative effects on health (e.g., due to sleep deprivation) on humans and wildlife. Therefore light disturbances shall be reduced as much as reasonably feasible.

Light control strategies shall be assessed including, but not limited to:

- locating the facilities and access roads so as to minimize the negative effects of lights on humans and wildlife
- optimizing logistics in order to reduce the need for transportation during the night
- minimizing flaring
- using non-reflective materials
- limiting the off-site visibility of lights through the use of shielding or downward shining of the light source (especially during bird migration periods).

6.4 Emergency preparedness for environmental risks

Emergency preparedness shall take into consideration special needs for preventing the degradation of the environment at the relevant locations of the shale gas activities in question.

Other recommendations for emergency preparedness are described in [4.2.8](#) and [5.7.3](#).

6.5 Environmental monitoring and reporting

6.5.1 Environmental Baseline Study

An Environmental Baseline Study (EBS) shall document the characteristics of the surrounding environment in the area of direct influence, prior to the start of activities. The EBS will form the basis for the description of environmental sensitivities in the ES. The EBS may also provide supporting evidence in case of dispute with regards to environmental impacts at the project location, during or after the operations (e.g., claim of water contamination).

The EBS shall be based on bibliographic data, and on a site survey. The survey shall cover the shale gas activities site and its area of direct influence (see [6.1](#)). Topics for the survey include but are not limited to:

- groundwater source quality, including drinking water wells
- surface water source quality
- air quality
- soil quality
- fauna and flora diversity
- presence of invasive species
- background noise (air- and ground-borne)
- background vibrations (from other activities)
- an inventory of pre-existing wells (e.g., gas or water)
- the presence of methane seepage.

Water shall, at a minimum, be analysed for pollutants that are involved in shale gas operations, such as chemicals to be used in the hydraulic fracturing process, heavy metals (from flowback water), methane (biogenic/thermogenic), and NORM.

The EBS and sampling should be carried out by an independent third party, and analyses shall be undertaken by certified laboratories.

6.5.2 Monitoring

Environmental monitoring shall be implemented during all relevant phases of shale gas activities (e.g., after the hydraulic fracturing stage, during production operations). The monitoring shall cover the shale gas site and its direct area of influence (see [6.1](#)). The objectives and purpose of the environmental monitoring will be guided by the findings of the EIA and EBS. Topics to be included in the monitoring include but are not limited to:

- groundwater quality
- surface water quality
- air quality
- noise levels during operations.

Water shall, at a minimum, be analysed for pollutants that are involved in shale gas operations, such as chemicals to be used in the hydraulic fracturing process, heavy metals (from flowback water), methane (biogenic/thermogenic), and NORM.

Sampling should be carried out by an independent third party, and analyses shall be undertaken by certified laboratories.

All results shall be documented and used as part of the EMS.

6.5.3 Reporting

Reporting the emissions to air, water and ground, as well as the use of raw material should be carried out during all phases of the shale gas activities. This allows tracking the environmental performance as required by the EMS, and allows populating relevant databases for further use.

The following emissions and use of raw materials should be reported, at a minimum:

- water volumes and origin
- chemicals - nature and volumes
- sand volumes and type
- energy use by type of energy source
- estimated GHG emissions (vented, combustion, and fugitive)
- drilling mud volumes and treatment
- flowback water surface return rate
- produced water (incl. flowback and brine) volumes and treatment solution
- brine volumes
- spills volume, nature, location, and clean-up.

Data should be openly disclosed to relevant stakeholders. Updates should be issued regularly, e.g., monthly, quarterly or annually, as appropriate for the data being presented.

6.5.4 Post operations survey

A post operations survey (POS) shall document the characteristics of the surrounding environment at the shale gas activity location after the operations. When compared to the results from the EBS (see 6.5.1), the POS will allow assessing environmental impacts from the operations.

The POS shall be carried out after the site is reclaimed.

Topics for the survey include but are not limited to:

- groundwater quality, including drinking water wells
- surface water quality
- air quality
- soil quality
- fauna and flora diversity
- presence of invasive species
- presence of methane seepages.

Water shall, at a minimum, be analysed for pollutants that have been involved in the operations, such as chemicals used in the hydraulic fracturing process, heavy metals (from flowback water), methane (biogenic/thermogenic), and NORM.

The POS should be carried out by an independent third party, and analyses shall be undertaken by certified laboratories.

Depending on the results of the POS, the implementation of additional remediation measures may be required.

7 Well Risk Management

7.1 Introduction

This section provides recommended practices for the management of specific shale gas well risks. The complete well risk scenario is made up by these risks and the risks common for shale gas activities and conventional gas activities.

Typical specific shale gas risks are related to the following:

- a large number of wells, and a high density of wells, within the field
- risks to groundwater from well operations and wells
- hydraulic fracturing may introduce seismic events and adversely influence well integrity.

The operator shall have a systematic risk management system in place that covers the processes of planning and execution of drilling and well completion operations, hydraulic fracturing, well maintenance, production operation and plugging and abandonment (see Sec.4).

Traceability in the planning and execution of the operations shall be ensured in order to enable verification that the defined safety level and well integrity are maintained in all phases.

The following standards provide guidance:

- API guidance document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines
- API guidance document HF2, Water Management Associated with Hydraulic Fracturing
- API guidance document HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing

7.2 Well barriers

There shall be clearly defined barriers in place to prevent:

- uncontrolled flow of natural gas to the environment
- cross flow between adjacent formation layers
- contamination of groundwater during drilling and cementing operations, during the subsequent production phase, until a well is abandoned.

Well barriers are envelopes of one or several dependent well barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to the surface.

Generally, the configuration of well barriers will vary for the different operational phases; however, it shall be clearly defined for each phase. The functional requirements for each barrier and its controls should also be defined for each operational step.

Geological formations may also be part of the well barrier envelope. The different geological formations overlying and underlying the target zone, also referred to as formation boundaries, should be located and characterized. Preventive measures shall be implemented to avoid fractures from breaching these formation boundaries. It is important that the formations enclosing the fractures do not allow cross flow between adjacent formations. Cross flow towards surface or towards the well via adjacent formation layers is a concern; especially when groundwater entities are located nearby or along the well trajectory. The effectiveness of the well barriers should be monitored throughout the life-cycle of the well. Frequency, extent and method of monitoring of the barrier elements should be determined on the basis of assessments of the importance of the barriers in mitigating risks. Particular attention should be paid to the condition of the well barriers during and after the hydraulic fracturing process.

The following standard provides guidance on well barriers:

- API standard 65 - Part 2, Isolating Potential Flow Zones During Well Construction.

7.3 Geological risks

The main geological risks associated with shale gas operations involve groundwater contamination and micro-seismicity events.

The geological risks involving groundwater contamination primarily relate to shallow producing zones or to pre-existing faults in the producing zone connected to the surface or groundwater zones.

Isotropic and homogeneous rocks seldom occur in nature. Most rock masses present a degree of anisotropy and heterogeneity. This implies that the physical, dynamic, thermal, mechanical, etc. properties of rocks vary in direction. Geological stresses, rock geomechanical properties and hydraulic fracturing process design are the most significant constraints on fracture growth but due to stress anisotropy it is often complicated to determine the direction and extent of fracture propagation. Furthermore, the production of gas from the reservoir will reduce the pore pressure and thereby change the original state of stress.

The direction, shape and extent of induced fractures can be anticipated using recognized geomechanical and engineering methods but uncertainties in quantitative predictions can be significant due to the limited data that can be practicably collected from the relevant underground formations and fundamental limits to the resolution of predictive models. The natural properties of the target formation for fracturing determine the final shape and direction of the induced fractures. Careful design, planning, monitoring and execution of the fracturing process can provide high confidence that the final realized fractures do not introduce unacceptable environmental consequences. In addition, induced fractures may intersect pre-existing fractures which can then dilate and propagate fracturing fluids in ways not planned for and that should be avoided. The most relevant example of this is the case of fugitive fractures. Induced fractures may extend upward beyond the target gas producing zone despite careful design and planning. The main cause would likely be existence of undetected pre-existing fault/fracture surfaces that can intersect the production well itself at a shallower depth, and which is intersected by an induced fracture. Such a fugitive fracture may continue to propagate along the wellbore by creating a micro-annulus between the cement and rock formation and potentially reach the groundwater. Alternatively, in the case of shallow producing zones, it may reach the groundwater through direct fracture propagation (i.e., not along the wellbore) depending on vertical distance separation between the groundwater and the producing zone.

The operator should therefore characterize the in situ stresses within the target formation as part of the planning and design process in advance of drilling and fracturing operations. Special emphasis should be made to understand and map possible stress field anisotropies at the specific site for shale gas production in order to reliably predict the direction and extent to which fractures will tend to propagate. It is expected that the key

data source for this will be well breakouts observed in exploration wells in the area in addition to well breakout data from production wells (collected before completion and the fracturing process).

As part of understanding the geomechanical stress state of the target formation and improving predictions of induced fracture growth, it is essential that the actual fracture creation and propagation is monitored in real time using BAT micro-seismic arrays and methods that allow direct location of and indirect observation of subsequent induced fracture surfaces. The resulting observed induced fracture geometry, direction and extent should then be compared to values predicted for these. If there is considerable deviation between predictions and observations, any necessary model revisions, corrections and updates should be performed in time to improve the design, planning and execution of future fracturing operations. This micro-seismic data may also have value in the resolution of potential claims of groundwater contamination.

In order to avoid possible groundwater contamination from induced fractures, the operator should estimate:

- the minimum required vertical separation between the deepest groundwater formation boundary and the shallowest edge of induced fractures
- the minimum required distance between the wellbore above the target shale gas formation and the nearest edge of an induced fracture
- the minimum required distance between the outermost edge of an induced fracture and any nearby wellbores
- the minimum required distance between any identified pre-existing faults or fractures to the nearest edge of an induced fracture.

Computerized simulation of fracture creation and growth should be used to design and plan the hydraulic fracturing process to satisfy these minimum distance requirements. The computer simulations should also contribute to establish a high degree of confidence that these minimum distances are achievable during actual fracturing operations. Site specific data acquired during exploration should be used to develop the simulation model.

The operator should carefully monitor fracture evolution during the hydraulic fracturing operations to ensure that induced fractures are created in a manner that satisfies the minimum distance requirements above.

Micro-seismic events are a routine feature of hydraulic fracturing and are due to the propagation of induced fractures. Larger seismic events are generally rare but can be triggered by hydraulic fracturing in the presence of a pre-stressed fault. In order to mitigate unacceptable induced seismicity the operator should carry out site specific surveys to identify directions of local stresses and locations of pre-existing faults. Once identified, these should be characterised and compared with historical records to assess the risks of larger induced seismic events, particularly ground accelerations near engineered structures.

Micro-seismicity should be monitored by the operator using appropriate monitoring tools and layouts before, during and after hydraulic fracturing in order to locate and mitigate any risks associated with induced seismicity.

7.4 Well planning

There is the potential risk of contamination of groundwater by drilling fluids, fracturing fluids, cement or natural gas. The overall risk of groundwater contamination shall be considered during well planning. Therefore the following should be assessed:

- The use of additives in the drilling fluid and hydraulic fracturing fluid which may pose toxic hazards or potentially degrade groundwater. The specific toxicological profile and planned volumes of such additives should be documented. In cases where it can be reasonably expected that significant drilling losses can occur in the groundwater, the drilling plan should include enhanced drilling design and procedures to minimize contamination of the groundwater to acceptable levels. A probabilistic estimate should be made of the overall contamination load from the drilling and fracturing processes on all contacted groundwater formations.
- The visualization of the actual hydraulic fractures, their location, shape and extent, as witnessed in real time during their creation in the fracturing operation, should be planned for. This will allow for direct judgement as to the vertical extent of the created fractures and if required minimum distances are satisfied. Real-time monitoring of induced fracture creation will also allow the fracturing operator to stop pumping before the minimum distance criteria cannot be complied with. The best available technology (BAT) for this may be installing an array of passive micro-seismic sensors in the near vicinity, and possibly within the wellbore. Use of highly sensitive tilt meters installed in near-surface environment may also be considered, but these are not expected to provide data that directly indicates geometric detail of the created fractures.
- Sufficient knowledge of the pre-existing water quality of all groundwater formations and the depths of the main formation boundaries of those to be drilled through, should be collected as part of a baseline survey of site conditions before drilling, fracturing and production. This data should be provided by or verified by an independent third party.

7.5 Contingency planning

A contingency plan for the case of failing or degrading well barriers shall be established prior to operation. The contingency plan should also consider monitoring means to validate the effectiveness of the well barriers (formation layers, cement, casings etc.). Typical measures may be increased monitoring, escalating to repairs.

The operator shall prepare a contingency plan for the case that the hydraulic fracturing operation induces breaches of the barrier system to maintain wellbore integrity, or creates fractures that do not satisfy minimum distance criteria.

For the case that operational restrictions prevent the planned cement length from being constructed, the operator shall have a contingency plan in order to achieve the required level of well integrity.

Appropriate contingency plans should be in place to act on detection of abnormal annuli pressures.

7.6 Well design

Wells shall be designed to maintain well integrity during well construction, including hydraulic fracturing, production and maintenance, thus preventing groundwater pollution caused by communication between adjacent formation layers or unintended flow into the well from the formation.

The well design and operational processes should be based on the principles in the following, or equivalent, guideline:

- API guidance document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines

The following recommended practice provides guidance on a systematic approach to qualification of the well design and the operational procedures:

- DNV-RP-J203 Geological Storage of Carbon Dioxide

7.6.1 Casing design

The casing design shall ensure that well integrity is maintained during all operational phases to avoid migration of fluids or natural gas to groundwater or to the surface or the air.

In addition to planning of a conventional well, the following issues related to casing design and planning shall, at a minimum, be observed to prevent migration of hydrocarbons to groundwater and cross flow between adjacent formations:

- casing and liner set points should be selected to minimize the risk of contamination of groundwater by drilling fluids, cement, stimulation fluids, and hydrocarbons
- casing strings and liners should be designed for maximum expected pressure during installation, hydraulic fracturing, and production.

A sketch of a shale gas well is exhibited in Fig. 7-1.

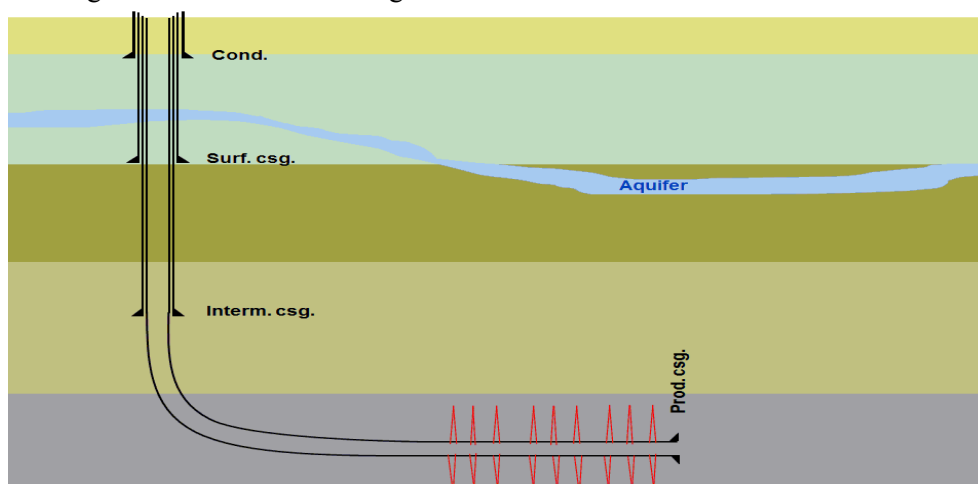


Figure 7-1
Well schematic (not to scale)

7.6.1.1 Production casing

For horizontal or deviated well sections, proven methods to isolate the casing string from the formation should be assessed. The casing should be cemented as high as possible above the previous casing shoe. The best available technology, under consideration of the ALARP principle, should be used to hinder degradation of the cement bond. Other alternative material or equipment used to isolate the casing from the formations should be

documented and proven to be as effective as cement for its purpose.

7.6.2 Cementing design

The cement shall be designed to maintain well integrity, provide structural support to the well and provide zonal isolation between different formations. In particular the functional requirements for the cement include:

- avoiding contamination of aquifers during cementing
- maintaining well integrity during the hydraulic fracturing process
- maintaining well integrity during drilling and production.

The cement barrier elements that prevent flow from the fracturing zone or from the natural gas bearing zone shall be clearly defined. This cement shall have sufficient length (typically 100 to 200 m with reference to recognised standards), be systematically qualified for the application, and be proved to be installed with the intended quality. The cement shall be verified by cement bond logs (CBL) or similar logging tools, in addition to monitoring of: volumes pumped, volumes returned to surface, circulating pressures etc. The qualification of the cement should include validation that the cement can be pumped and cure to the intended quality with the defined functional properties.

The casing program and cementing design shall strive to minimize the probability that a micro-annulus can develop during the various phases of wellbore construction, hydraulic fracturing and production operations.

Particular attention shall be paid to cement design in horizontal and inclined sections of the well. Preventive measures shall be evaluated to reduce the risk of obtaining a weakened cement sheath, which is a challenge particularly in horizontal well sections where water may naturally be trapped in the upper portion of the bore. A uniform banding of the cement around the casing is crucial for a successful cement job.

All casing strings should meet recognized industry recommendations for cementing procedures. In cases where this is established not to be technically feasible, or desirable, alternative designs should be developed which provide the same level of safety as such recommendations.

The following standard provides guidance:

- API standard 65—PART 2, Isolating Potential Flow Zones During Well Construction

7.6.2.1 Cement bond logging

Cement logging represents a core quality control procedure in the construction of shale gas wells.

Casing cement that forms part of the well barrier envelope in the fracturing or production operation shall be verified by cement bond logs. Additional and more accurate measuring tools should be considered to verify the quality of the cement in deviated and horizontal well sections, e.g., 360 degree measurement.

In cases where the level of well integrity is reduced as a result of the hydraulic fracturing, required remedial action shall be identified through a risk assessment. It is important to track local changes of the production casing/liner and the interface between the casing wall, cement and formation. Procedures for downhole logging after hydraulic fracturing operations should be established, as required based on a risk assessment.

The following standard provides guidance:

- API TR 10TR1, Cement Sheath Evaluation

7.6.2.2 Pressure testing

Pressure testing shall be performed in accordance with recognised methods and procedures for conventional natural gas activities.

In addition the following should be included:

- cement barriers should be tested to the pressure they are designed to and in the direction of the flow
- prior to hydraulic fracturing operations, all equipment should be tested to verify that it is in proper condition.

7.7 Drilling operations

The operator should endeavour to minimize contamination of groundwater by drilling mud, cement or hydraulic fracturing fluids.

Care should be exercised in the design of drilling mud, in particular where the uncertainty in pore pressure and fracture pressure (pressure window) is large.

If information on the local formation properties and formation pressure capacities is limited, a pilot hole may be considered to be drilled through groundwater aquifers to reduce the flow area between the well and the formation. The size of the pilot hole may be small as long as the annulus clearance is sufficiently large to avoid increasingly high equivalent circulating density. High equivalent circulating density can cause fracture of formation, and cause drilling fluid to flow into the groundwater.

It is recommended to drill the well with a hydraulic well pressure slightly higher than the pore pressure of the

aquifer as long as well control is maintained throughout drilling through the groundwater. A possible measure to prevent loss of drilling fluid into the groundwater, may be the use of lost circulating material to enhance the effectiveness of the drilling fluid filter cake established along the open hole wall. The filter cake reduces permeability and therefore reduces leakage into the groundwater if the hydraulic well pressure minimally exceeds the fracture pressure. All lost circulating material used shall be harmless to the environment and shall not impact the groundwater.

Methods based on underbalanced drilling, which have been subject to technology qualification, may offer an alternative to conventional drilling in order to minimize the contamination of groundwater aquifers. An advantage of underbalanced drilling is that a minor amount of groundwater will flow into the wellbore in a controlled manner during drilling and thereby prevent drilling fluid to flow into the formation and mix with the groundwater. This can be obtained as long as the pore pressure is sufficiently higher than the formation collapse pressure.

7.7.1 Well control and monitoring

The conditions of the well should be continuously monitored as for conventional natural gas wells. In addition, it is recommended that, at a minimum, the following issues are properly monitored and controlled during hydraulic fracturing operations:

- well kicks
- volume control of hydraulic fracturing fluids
- return flow of hydraulic fracturing fluids
- detection and responses to the release of hazardous gas, H₂S, etc.

There should be systems in place to detect annular pressure build-up in relevant annuli (A, B, C etc.) to detect abnormalities in the hydraulic fracturing operation.

7.8 Hydraulic fracturing

The hydraulic fracturing operations should be carried out such that the induced fractures satisfy the minimum required distances described in 7.3.

Best practice should be applied in order to maintain well integrity during perforation.

Best practice should be applied in order to maintain well integrity during hydraulic fracturing activities.

7.9 Well integrity in the operational phase

The integrity of shale gas wells may be compromised during the operational phase by erosion, corrosion and changed geological conditions. The predominant risks are related to gas migration.

The operational phase is defined as the period of time from well completion until final well plugging and abandonment.

7.9.1 Inspection

Procedures for inspection of production wells should be established.

Procedures for inspection of production wells located at fields where groundwater aquifers exist shall be established, with the added purpose of detecting contamination of the groundwater. Logging of the wells shall be performed in all circumstances where contamination of groundwater is observed. If this is found to be due to the shale gas wells or other shale gas activities, necessary measures shall be implemented to cease the contamination.

7.9.2 Monitoring

Methods and frequency for verifying the condition of the well barrier(s) shall be defined and documented. All instrumentation used for required monitoring of relevant parameters should be regularly checked/tested and calibrated.

There should be systems in place to detect annular pressure build-up in relevant annuli (A, B, C etc.) to detect abnormalities in the production operation.

Upon detection of annular pressure, the operator should determine the appropriate diagnostic testing program for the well.

The following standard provides guidance:

- API RP 90, Annular Casing Pressure Management.

7.10 Well abandonment

Decommissioning shall be done through permanent plugging of the well.

The well shall be abandoned with an eternal perspective, where two barriers shall be required in order to prevent natural gas from flowing from the reservoir to aquifers or external environment.

The risks related to time effects on well barriers such as long term development of reservoir pressure, possible deterioration of material used, sagging or settling of weight-increasing materials in well fluids, etc. shall be assessed.

7.11 Field staff training

The hydraulic fracturing process is a critical operation and personnel involved with the planning, execution and validation shall be appropriately competent (see 4.2.6).

8 Water and Energy Resources Risk Management

8.1 Introduction

The purpose of this section is to recommend practices for the management of water and energy used for shale gas activities. The purpose is to minimize environmental and societal impacts associated with the acquisition and use of water and energy resources associated with the process of hydraulic fracturing and other shale gas activities.

8.2 Water resources

Considerations shall be given to planning associated with water acquisition, use, and management for shale gas activities. Due to resource and environmental concerns the operator shall identify, assess and implement strategies for minimizing the use of water.

The main issues in shale gas operations related to water concern:

- the origin of water (source water acquisition)
- water withdrawal amounts over time
- water transport (from the source to the well site and from the well site to the point of treatment and/or disposal)
- water storage
- water use in the activities, including adding of chemicals
- water treatment and re-use or recycling
- water treatment and disposal (treatment prior to disposal or disposal with treatment by-products).

Operators should engage with municipal water suppliers at the earliest opportunity when considering options for water use. In many cases water suppliers will have a catchment water resource plan that will aid the operator in determining the optimal water resource option, and any fall-back plans.

8.2.1 Water acquisition and withdrawal

The operator shall conduct a detailed, documented review of the water management issues assessing the adequacy of the supplies on the basis of the predicted water needs. The considerations shall entail:

- water source capacity, including other consumption of the water and seasonal variations in water supply
- predicted water needs for the shale gas activities over time
- water handling and storage
- transportation considerations
- water treatment and disposal.

In addition, the environmental effects of water use and management shall be considered (see Sec.6).

The operator should consider the cumulative water demand, as well as the timing of these needs at the individual well site. This should include consideration of the water requirements for drilling operations, dust suppression, and emergency response, along with the water requirements for hydraulic fracturing operations.

The operator shall determine whether or not the sources of water are adequate to support the total operation, with water of the desired quality, and that these needs can be accessed when needed for the planned development program.

8.2.1.1 Use of surface water

The withdrawal of water from surface water bodies, such as rivers, streams, lakes, natural ponds, private stock ponds, etc., may require landowner permission. In some regions, water rights will be a key issue. In addition, applicable water quality standards may prohibit any alteration in flow that may impair a fresh surface water body's highest priority use, which is often defined by local water management authorities. The amount of water needed should also be considered to ensure that water withdrawals during periods of low stream flow do not affect aquatic life, recreational activities, municipal water supplies or other industrial facility usages, such as usage by power plants.

The operator should consider the issues associated with the timing and location of withdrawals since impacted watersheds may be sensitive, especially in drought years, during low flow periods, or during periods of the year

when activities such as irrigation place additional demands on the surface supply of water.

If large-scale water diversion plans during periods of peak river flow are considered then the operator should consider that this approach may normally require the development of sufficient water storage capabilities to meet the overall requirements of drilling and hydraulic fracturing plans over the course of a season, year, or perhaps even over a multi-year period (to plan for possible periods of drought).

In other cases, rain water harvesting may be an option. This may require assessment of site suitability, and detailed planning.

8.2.1.2 Use of groundwater

Whenever practicable, the operator should consider using water resources other than potable water or legally protected/protectable water resources for drilling and hydraulic fracturing. Many of the concerns about water supply may be mitigated if lower-quality subsurface water sources are used. However, this may require the drilling of source water wells that are deeper than publicly used potable water aquifers. Deeper water may contain additional constituents that may require treatment.

The operator shall ensure that drilling for water will not negatively impact the available freshwater zones and should consult with water management authorities and consider undertaking a study to determine the feasibility of success in such areas.

The primary concern regarding subsurface water withdrawal is temporary aquifer volume diminishment. In some areas, the availability of freshwater is limited, so withdrawal limitations may be imposed. In such circumstances, the operator should consider groundwater replenishment requirements.

Another groundwater protection consideration is locating water source wells for shale gas operations at an appropriate distance from other water bodies and/or supplies. The operator shall provide evidence of the existence of public or private water wells and domestic-supply springs within an acceptable distance to any proposed drilling location.

8.2.1.3 Use of other water supplies

Obtaining water from municipal supplies may be considered, but the water demand for hydraulic fracturing shall be balanced with other uses and community needs. This option might be limited, since some areas may be suffering from current water supply constraints, especially during periods of drought. The long term reliability of supplies from municipal water suppliers should be carefully evaluated. However, in the absence of adequate municipal water supply infrastructure at the location of the drill site, operators may be required to participate financially toward upgrading infrastructure in order to enable a municipal supply to be accessed.

Other possible options for source water are municipal wastewater, industrial wastewater, and/or power plant cooling water.

8.2.1.4 Use of reservoir water and recycled flowback water

Produced reservoir water and recycled flowback water shall be treated and reused in the shale gas activities if this is technically feasible at reasonable costs.

Natural formation water may contain minerals native to the reservoir rock. Other water quality characteristics that may influence water management options for fracturing operations include concentrations of hydrocarbons (analysed as oil and grease), suspended solids, soluble organics, iron, calcium, magnesium and trace constituents such as benzene, boron, silicates, and possibly other constituents. Water quality issues and their environmental impacts should be carefully evaluated by the operator.

The following standard provides guidance:

— API guidance document HF2, Water Management Associated with Hydraulic Fracturing

8.2.1.5 Water resource replenishment

The consumption of surface water and groundwater systems for shale gas project purposes should support withdrawals based primarily on water replenishment (recharge). This implies that regions where shale gas projects are planned should satisfy the water budget in the watershed such that withdrawals shall be recharged by comparable precipitation that will replenish surface and groundwater over the period of the planned operations.

The amount of groundwater available from a well and the associated aquifer should be determined by performing a pumping test to determine the safe yield, which is the amount of groundwater that can be withdrawn for an extended period without depleting the aquifer. Non-continuous withdrawal from groundwater sources should be encouraged to provide opportunities for water resources to recover during periods of non-pumping.

Short-term variations in precipitation may result in droughts and floods which affect the amount of water available for groundwater and surface water replenishment. These variations shall be accounted for in planning water resource use.

8.2.2 Water and other fluid handling and storage

Fluids handled at the well site both before and after hydraulic fracturing should be stored on-site. Fluids used for hydraulic fracturing may generally be stored onsite in tanks or lined surface impoundments. Returned fluids, or flowback/produced water, may also be directed to tanks or lined pits.

The operator shall maintain and observe relevant information about water management and storage operations at the site. Such information shall include the following:

- information about the design and capacity of storage impoundments and/or tanks
- information about the number, individual and total capacity of receiving tanks on the well pad for fresh water storage
- information about the number, individual and total capacity of receiving tanks on the well pad for flowback water
- information about the number, individual and total capacity of receiving tanks on the well pad for produced water
- a description of planned public access restrictions, including physical barriers and the distance to edge of the well pad
- description of how liners are to be placed to prevent possible leakage from such impoundments, especially from flowback water.

The operator storing flowback water on-site should use watertight tanks located within secondary containment, and should remove the fluid from the well pad in a timely manner.

Levels of liquid in tanks and pits shall be monitored at least daily. In case tanks or pits contain other liquids than fresh water, storage filling levels should be monitored by instrumentation and alarms.

Appropriate inspection and maintenance plans shall be in place for all storage facilities.

Recommendations for minimizing environmental concerns from storage are provided in [Sec.6](#).

If lined impoundments or pits are used for storage of fracture fluids or flowback water, the pits shall comply with applicable standards, good industry practice and liner specifications. To enhance efficiency and limit the number of impoundments, the operator may consider the use of centralized impoundments. These impoundments shall be designed and constructed in such a manner as to provide structural integrity for the life of their operation and prevent failure or unintended discharge. Pits used for long term storage of fluids shall be placed at distances from surface water in order to prevent uncontrolled overflows from reaching the surface water.

8.2.3 Water disposal

The operator shall prepare for the proper management and disposal of fluids and residuals which can not be re-used in the shale gas activities. Considerations for fluid management shall include transport off the well site and treatment and final disposition of any surplus fluid components. Municipal sewer service suppliers may provide discharge options that could be utilised by operators.

Reference is made to [Sec.6](#) for environmental management recommendations and [Sec.9](#) for transportation recommendations.

8.3 Energy efficiency

The energy efficiency of the project shall be optimised as much as reasonably practicable. Energy efficiency shall be considered and implemented through the design and operation of the activities. The operator should apply benchmarks for a total assessment of the energy consumption.

Energy efficiency optimization strategies shall be considered, including but not limited to:

- use of the most energy efficient equipment, taking into account all potential operation scenarios
- energy efficient procedures for equipment start-up and shutdown
- the reduction of transportation for equipment, raw materials and waste
- energy collaboration or sharing with other users
- electrification from the grid
- avoiding venting and flaring at all stages by prevention or collection and export of hydrocarbon emissions, without compromising the safety performance of the project (as discussed in [6.3.5](#)).

Energy sources to be used during all phases of the project should be selected at the design stage, applying the principles for energy efficiency and cleaner energy sources stated above (see also [Sec.6](#)).

The selection shall take into account logistical and operational aspects. The amount of energy required per type of energy source, as well as storage requirements, for e.g., of diesel, shall be estimated as part of the selection process.

Energy use by type of energy source shall be monitored and reported as part of the project EMS (see [Sec.6](#)).

The energy management system should comply with either of the following standards:

- ISO 50001 Energy management systems - Requirements with guidance for use
- EN 16001 Energy management systems - Requirements with guidance for use

9 Infrastructure and Logistics Risk Management

9.1 Introduction

This section describes the recommended practices for management of risks from shale gas activities infrastructure and logistics facilities and operations.

Shale gas development and operations can involve considerable infrastructure development and logistics operations. The operator shall plan and document that development, operation and abandonment of infrastructure and logistics is conducted such that the footprints from infrastructure and logistics are as small as reasonably practicable.

9.1.1 Geographical scope

The operator shall ensure that the geographical scope comprises all requirements for use of existing, changed use of existing and new development of infrastructure and logistics in order to support the shale gas development including, but not be limited to:

- well site developments
- permit area developments
- developments adjacent to the permit area, and within the larger area of the play
- developments beyond the play.

9.1.2 Interdependency risk

When a comprehensive scope of infrastructure and logistics operations is required within a confined development area, the operator shall assess and document how additional risks due to dependent activities and activities in parallel will be managed. Examples include:

- land use minimization increasing the risk related to close encounters
- activities performed in parallel
 - infrastructure development
 - well construction and completion
 - production and processing
- temporary infrastructure leading to a dynamic navigable landscape
- movable, heavy equipment
- the pace and scale of the development.

9.2 Logistics risk management

Logistics is defined as sourcing, supply, transportation, storage, and material handling, both inbound and outbound, of all equipment and material required for the shale gas activities, through all phases.

The logistics will cover equipment and material for development of transport infrastructure and all other infrastructure, including abandonment of the infrastructure, and the restoration of the used land, as well as to activities which support the drilling, hydraulic fracturing, production and well stimulation operations.

Required supplies of equipment and material to support up-keep of the infrastructure are part of logistics.

The additional risks due to increased logistics activities shall be mitigated, as far as reasonably practicable, to meet operator's objectives.

9.2.1 Logistics impact assessment and logistics statement

A logistics impact assessment shall be carried out covering all relevant phases. The logistics impact assessment should be carried out in the concept selection and design phases, and serve as input to the Environmental Impact Assessment (see 6.2). The logistics impact assessment for the exploration phase may be executed separately.

The logistics impact assessment shall cover all logistics operations from, but not limited to, infrastructure (see 9.3), wells (see Sec.7), resources (see Sec.8), and the environment (see Sec.6).

The results from the logistics impact assessment shall be documented in a logistics statement.

Information provided in the logistics statement shall include, at a minimum:

- the logistics criteria of the shale gas activities
- a description of the project logistics area of influence
- the demand for logistics activities per project phase, including but not limited to gross demand and periodical demand for different development alternatives

- the use of Best Available Techniques for logistics and Best Logistics Practices
- possible measures to reduce negative logistics impacts.

9.2.2 Logistics area of influence

The logistics area of influence shall be assessed as part of the logistics impact assessment.

The logistics area of influence is defined as the area most likely to be affected by the logistics of the shale gas activities. The extent of the logistics area of influence will at a minimum cover the direct area of influence relating to the environment, or the defined site area, as well as all supply chains, defined by the geographical location of all sourcing sites providing equipment or material to the activities, including alternative transport routes and related terminals, and all distribution chains for produced products and waste, defined by the geographical area of deposit, including alternative transport routes and related terminals.

The extent of the logistics area of influence depends on the shale gas activities' sourcing requirements, the distance to the sourcing options, and alternative transport routes.

9.2.3 Best Available Techniques and Best Logistics Practices

The shale gas activities shall as far as is reasonably practicable apply Best Available Techniques (BAT) related to logistics and Best Logistics Practices (BLP) to minimize the logistics footprint.

BAT and BLP assessments shall be conducted at the concept selection and design phases, and shall be planned for implementation for the development phase, the production operation phase and the abandonment phase.

The use of Best Available Techniques for logistics and Best Logistics Practices shall be documented in the Logistics Statement.

9.2.3.1 Best Available Techniques

Best Available Techniques for logistics shall be applied as far as reasonably practicable to derive solutions that best meet the multiple criteria and objectives. Such may include, but are not limited to:

- transport optimization including network design, transport route, and vehicle scheduling optimization
- multi-criteria and multi-objective techniques precisely defining weights given to specific criteria, for instance GHG emissions from transport versus the land surface footprint of transport infrastructure
- measures to address security, and risk and resilience in supply chains
- tracking and tracing technology to be applied for transport units to monitor their use in real-time and for monitoring and reporting purposes
- the multi-modal design of transport chains to better include choice of transport mode dependent on distance and transported volumes, increased flexibility in transport chain design, and option for better utilization of existing transport infrastructure
- engine technology, for instance gas-driven or dual-fuel, to reduce GHG emissions.

9.2.3.2 Best Logistics Practices

Best Logistics Practices may include, but are not limited to:

- the demand for equipment and material is the primary mover for the scope of logistics services. The operator may achieve substantial reduction in the scope of logistics services and a reduction in the logistics footprint with good demand management.
- the operator shall use sound logistics management principles to meet demand for logistics services in the most resource effective way, with the least footprint
- the operator shall document a demand management system covering how to manage the demand for logistics services from the different categories within the project life cycle phases
- the operator shall document the choice of transport mode based on volume of cargo to be transported, type of cargo and transported distances
- the operator shall actively seek to establish collaboration, for instance, for, but not limited to:
 - improved logistics support
 - better utilization of logistics resources, and
 - a reduced adverse footprint from logistics.

9.2.4 Logistics impacts

The following sections address impacts and measures for the prevention, minimization, and mitigation of adverse impacts from logistics facilities and operations. As a general principle, preventive measures shall be favoured over mitigation or compensatory measures.

Implementation of proposed measures shall not compromise the safety performance of the shale gas activities.

The main findings from evaluations required in this section should be presented as part of the logistics impact assessment. The logistics impact assessment shall refer to the logistics baseline survey, shall comprise all relevant alternative logistics designs for the development, and shall comprise all logistics impacts, including but not limited to those stated below.

9.2.4.1 GHG emissions

GHG emissions from logistics operations shall be reduced, as far as reasonably practicable, to meet operator's objectives.

GHG emission reduction strategies for logistics to be implemented during all phases of the project should include, but are not limited to:

- reducing transported volumes through proper logistics demand management (see 9.2.3)
- identifying the choice of transport mode with the lowest GHG emission per unit transported
- including GHG emissions from trans-loading operations in the assessment of the total supply and transport chain GHG footprint
- enabling use of carbon lean fuels, e.g., through dual-fuel engine requirements.

GHG emissions shall be reported as part of logistics reporting.

9.2.4.2 Other emissions

Other emissions originating from logistics shall be reduced, as far as reasonably practicable, to meet operator's objectives. Such emissions include, but are not limited to:

- particles, NO_x and SO_x emissions from the combustion process of transport vehicles, terminals and storages
- noise from engines and operation of transport infrastructure
- dust from operations on transport infrastructure.

As several of these other emissions have a stronger local impact, routing of transport chains should seek to avoid populated areas, and especially densely populated areas.

9.2.4.3 Hazardous materials

Logistics will transport chemicals into the shale gas activities area to be used in the drilling and hydraulic fracturing operations, and will transport out waste material, radioactive logging tool sources and NORM from the shale gas area. Both the inbound and outbound transport from the area of such material is defined as transport of hazardous material.

Transport of hazardous materials through vulnerable areas shall be reduced, as far as reasonably practicable, to meet operator's objectives and not add unnecessary risk.

Vulnerable soil areas may be sensitive to spill consequences of hazardous materials, populated areas, or high-traffic transport routes and road/rail junctions with a higher likelihood of traffic-based risk.

9.2.4.4 Spills

The risk from spills of hazardous materials shall be reduced as far as reasonably practicable. Spills may be due to scenarios such as, but not limited to:

- the trans-loading of cargo from storage tank to transport vehicle tank, or between transport vehicle tanks in a multi-modal chain
- the fuelling of transport vehicles
- a cargo spill due to a traffic-based accidental event
- a fuel spill due to a traffic-based accidental event.

9.2.4.5 Traffic based risks

A shale gas development will contribute to a relative change in traffic-based risk in the transport systems that are affected. The relative changes in traffic load and traffic density are two issues which contribute to the relative change in traffic based risk.

The relative impact from the shale gas development on traffic-based risk shall be assessed and documented.

Traffic load may as part of a traffic-based risk picture be defined as the relative change in the number of heavy duty vehicles due to shale gas development.

Relative changes in traffic density in related traffic systems beyond the site should be kept as low as reasonably practicable.

Risk reduction measures should include, but are not limited to:

- proper logistics demand management to reduce demand for transport and related traffic growth
- the use of alternative transport modes and transport systems
- routing of transport through several transport channels
- the distribution of traffic over time
- restrictions on transport during rush hours.

A traffic plan for the shale gas activities which supports the operations criteria shall be developed. The traffic

plan shall comprise usage of both existing and new transport infrastructure and include, but not be limited to:

- traffic frequency
- operational hours
- transported volumes
- routing of transport resources
- impact analyses
- mitigating measures
- emergency preparedness.

9.2.4.6 Maintenance of transport systems

Increased logistics on established traffic and transport systems following from the shale gas development may require accelerated maintenance of transport system infrastructure.

Required additional maintenance requirements from shale gas project logistics shall be assessed and documented.

After abandonment, shale gas development related transport system maintenance shall be in the condition as estimated for normal wear and tear from other use beyond that of the shale gas activities.

9.2.4.7 Logistics security risk

Logistics comprise a gateway between the site and the area beyond, and may represent a security threat both for the shale gas site and activities, the site neighbourhood and the areas affected by the shale gas activities' transport systems.

The security risks from logistics should be kept as low as reasonably practicable. Focus should be given, but is not limited to:

- sourcing and supply sites and loading
- transport resources
- transport channels
- access to shale gas development site
- treatment and storage on site.

The operator shall assess relevant security measures. The following standard provides guidance on security management systems:

- ISO 28000 Specification for security management systems for the supply chain.

9.2.5 Logistics interrelationships

The relationships among the logistics resources and functions shall be designed and managed to establish a well-functioning throughput through supply and distribution chains, without undue use of land for transport and logistics infrastructure development, balanced against adverse impacts from logistics operations.

9.2.5.1 Sourcing

The assessment and choice of sourcing sites shall take logistical requirements and effects into account including, but not limited to:

- the distance from the sourcing site to the development site
- alternative transport channels
- alternative transport modes and techniques.

9.2.5.2 Supply

The design and operation of supply and replenishment cycles shall be assessed including, but not limited to:

- transport requirements
- storage requirements.

9.2.5.3 Transport

Transport requirements may be stated in terms of:

- frequency
- load sizes and load units
- transport modes.

Transport modes shall be used according to best available techniques, given volumes to be transported and transport distances.

Transport resources shall, as far as reasonably practicable, seek to have full load units.

9.2.5.4 Storage

On-site storage of consumables shall, as far as reasonably practicable, be centrally located, with well pad specific storage sizeable to reduce traffic.

Size of storage infrastructure shall be balanced against replenishment cycles and derived transport requirements.

A criticality based assessment of storage requirements shall be made for all consumables and equipment, dependent on required response time to on-site demand.

9.2.6 Logistics monitoring and reporting

9.2.6.1 Logistics baseline survey

The operator shall prepare and document a logistics baseline survey that assesses and documents the logistics conditions prior to the shale gas development within the area defined as the logistics area of influence.

The logistics baseline survey shall be documented according to the scope of logistics and logistics criteria. This should comprise, but not be limited to:

- assessing and documenting available capacity and limitations on logistics infrastructure along all supply and distribution chains
- identifying both primary and alternative transport routes, supply and distribution channels
- identifying logistics bottlenecks that should be improved
- identifying types, volumes and loads of existing traffic and transport
- developing measures for traffic and transport that document absolute and relative status, as well as distribution over time periods from day to year, including trend development
- identifying capacity of available terminal facilities.

The logistics baseline study may be based on, e.g.:

- bibliographic data
- traffic and transport statistics
- geographic information systems
- the mapping of infrastructure with relevant limitations such as, but not limited to, load capacity, width, height and length restrictions, operating hours, cargo type restrictions along supply and distribution chains
- trend data developments over a period of time preceding the development.

The logistics baseline survey shall, as far as reasonably practicable, document findings and conclusions in relation to geographic information systems such as, but not limited to, maps or atlases in either physical or electronic form.

9.2.6.2 Logistics monitoring

Logistics monitoring shall be implemented for the full life-cycle of the shale gas activities. The logistics monitoring shall cover the project logistics area of influence.

The criteria/topics included in logistics monitoring should be, as far as reasonably practicable, monitored both on an absolute level as related to the project, and as a relative change to the baseline survey.

Topics to be included in the logistics monitoring should include, but not be limited to:

- traffic volumes
- transport volumes and transport work performed in, e.g., tonne-km
- number of truck movements at the development's external borders
- axle loads of transport units – peak and average
- traffic and transport of hazardous materials
- trans-loading
- emissions
- incidents and accidents.

Tracking and tracing technology should be used as far as deemed effective to monitor logistics.

9.2.6.3 Logistics reporting

Logistics reporting shall be carried out for all phases of the shale gas activities.

Logistics reporting should cover, but not be limited to:

- types and number of transport resources used
- terminal and storage resources used
- traffic measures
- transport work in total and split per mode and type of cargo
- transport work of hazardous material

- incidents and accidents
- spills, split per type and volumes, with location
- use of fuel
- GHG emissions
- use of primary and alternative supply and distribution channels
- storage volumes
- trends and analysis related to the above should be taken from the time period preceding the shale gas development.

Relative measures may relate the absolute quantities to other characteristics of the development, for instance area covered, infrastructure units, the amount of energy produced. Logistics reporting should include relative measures, e.g.:

- transport work per well pad
- transport work per kWh produced.

9.2.7 Emergency preparedness and emergency response capacity

A logistics emergency plan shall be developed and documented as part of emergency preparedness. Special requirements for logistics as part of emergency preparedness shall, as far as reasonably practicable, be arranged in advance of potential need.

Areas in which logistics is critical include, but are not limited to:

- emergency logistics services: fire, medical, security
- access to and collaboration with public emergency logistics services
- access of transport resources into the site
- transport corridors and logistics resources for the evacuation of personnel
- re-routing of ordinary shale gas development traffic in case of emergency
- transportation to an alternative site
- response time from sources to site
- the capacity to get mitigating equipment and material into the site or an alternative site
- access to alternative sourcing sites
- access to alternative deposit sites
- management, transport and treatment of hazardous material (hazmat), including defined alternative hazmat supply and distribution chains
- supply chain critical vendors or service providers as part of the preparedness, response, continuity and recovery plans
- mutual aid agreements defining resources that may be shared with or borrowed from other organisations in case of emergency.

The operator shall establish documented procedures describing logistics plans to recover from the consequences of disruptive or emergency events, and to recover operations to a pre-determined level.

9.3 Infrastructure risk management

Infrastructure is defined as all interconnected physical structural elements in ground, on land surface and above surface erected or improved for the purpose of the specific shale gas development and operation.

Generally, the infrastructure will include, but is not limited to;

- transportation; roads, railroads, waterways, and ports and terminals
- energy supply
- processing
- product collection and distribution, including gathering lines and transmission lines
- water services
- solid waste services
- hazardous waste services
- spill containment
- emergency response services (security, fire, medical)
- housing and personnel services
- fixed or temporary infrastructure for collection, guiding to appropriate storage or treatment
- mitigation of spills or emissions.

9.3.1 Infrastructure impact assessment

Infrastructure for a shale gas development is here grouped into:

- shale gas specific infrastructure
- shared infrastructure.

The shale gas specific infrastructure is designed and constructed specifically for the shale gas activities, and

shall be abandoned and the land used restored after the infrastructure is no longer needed as part of the shale gas activities.

For all shale gas specific infrastructure, a principle of partial abandonment of infrastructure and restoration of land shall be followed throughout the development and operational life-cycle of the project if this does not lead to increased overall risk, additional impact at later stages in the shale gas activities' life cycle or could be a hindrance for emergency actions.

All infrastructure development shall include assessment of, but not be limited to the following:

- topography and potential impact on pipeline design, right-of-way maintenance, land erosion, and emergency response and containment of releases shall be assessed
- the use of fixed or flexible technology shall be assessed with regard to the estimated lifetime of the infrastructure and the lifetime of the shale gas operations
- for infrastructure that requires development of a corridor for conveying passage one should seek to co-locate several infrastructures into the same corridor as far as reasonably practicable to minimize surface impact
- due consideration should be taken to assess the use of flexible infrastructure technology versus the impact of additionally required logistics
- options to alter the scale of infrastructure to meet changes in requirements for product throughput or other requirements shall be treated explicitly
- the risk of possible infrastructure failure leading to any spill or emission shall be quantitatively assessed. Likelihood of failure, immediate consequences and area vulnerability shall guide the design and use of protective and mitigating measures.
- spill containment systems shall be assessed related to all infrastructures where there is risk of spills that could lead to irreversible adverse effect on soil, surface or air quality
- topsoil material removed in development of infrastructure shall as far as reasonably practicable be retained to ease land restoration and successful re-vegetation
- for infrastructure located in parallel in the same infrastructure corridor, a special assessment of interdependency risk shall be conducted. The same shall apply for infrastructure crossings.

9.3.2 Infrastructure area of influence

The infrastructure area of influence shall cover the area defined by infrastructure used and developed including, but not be limited to:

- acceptable existing infrastructure
- improved existing infrastructure
- new temporary infrastructure
- new permanent infrastructure.

The area of influence will cover both shale gas specific infrastructure and shared infrastructure.

9.3.3 Shale gas specific infrastructure

All shale gas specific infrastructure shall be designed and constructed to meet, at a minimum, the following scenarios:

- providing the best utility for the shale gas activities, without compromising on safety (following the ALARP principle)
- taking area specific adverse natural conditions into account
- appropriate rights-of-way for infrastructure to utilize the smallest surface area as far as reasonably practicable for safe operations
- infrastructure shall utilize the smallest practicable surface area consistent with prudent operations
- damage to surface and land used should be avoided as far as reasonably practicable
- the infrastructure chosen shall be accessible as far as reasonably practicable for maintenance and emergency response
- all infrastructures, both on the surface and subsurface, should be documented on geographical maps
- after construction of infrastructure, all adjacent land and access paths not required for maintenance and emergency response shall be restored as far as reasonably practicable before final restoration
- before removal of infrastructure, the infrastructure shall as far as reasonably practicable be split into practically sized elements suitable for removal, and protected/encapsulated to avoid spill or other risks during de-construction or transport
- after abandonment of the area, all surface area and subsurface used for infrastructures shall be restored as far as reasonably practicable to pre-development conditions as stated in the baseline survey, or changed into alternative use as agreed with the surface landowner or other relevant stakeholders.

9.3.3.1 Well pads

The well pad is the primary surface infrastructure for the development phase, in the drilling and commissioning of the well, as well as in the production operational phase.

The well pads shall be developed before drilling and well construction can commence.

The well pad shall be designed and constructed so as to meet, at least, the following criteria:

- as a first barrier the well pad should as far as reasonably practicable be placed in the terrain in such way that impact on vulnerable areas is minimized
- in the development phase, it shall meet area space and load requirements of the drilling and commissioning infrastructure to be placed on top of the well pad
- during the production operational phase, it shall meet area space and load requirements relevant to that phase, including well stimulation infrastructure
- as far as reasonably practicable, it shall have area space and load capacity to accommodate emergency infrastructure in case of an accidental event at the well pad
- leakage of chemicals or contaminated water shall be prevented from entering the soil, for instance, by use of a liner beneath the well pad, including a collection system of such leaked substance with a guide into collecting tanks/containers
- it shall withstand impacts from storm-water run-off, flood and forest fire etc. without the risk of equipment instability.

9.3.3.2 Processing facilities

Processing facilities include facilities used for processing of gas before transport by pipeline systems, and the processing of waste water and solid waste to the extent that such are to be processed at the site. The processing systems themselves as well as associated equipment are not covered by this Recommended Practice.

Infrastructure for processing facilities will typically comprise foundations, buildings, including any risk mitigating infrastructure.

Whether to have central processing facilities or have those in conjunction with well pads shall be decided for the specific development, based on minimizing the overall negative impact from development. Hence, further plans for development adjacent to the given site should be taken into consideration if this could call for future increases in throughput processing capacity.

The processing facilities shall be designed and constructed to meet, at a minimum, the following criteria:

- shall be designed and constructed in compliance with applicable standards
- shall be designed and constructed to achieve effective utility according to anticipated life-time and future development prospects
- as a first barrier, the processing facilities should as far as reasonably practicable be placed in the terrain in such way that any impact on vulnerable areas is minimized
- shall have area space and load bearing capacity to cater for processing systems and equipment.
- shall have appropriate spill control measures in place
- shall be placed and measures developed in place to mitigate noise, light and dust that could be inconsistent with occupational or public health requirements
- due consideration should be taken to reduce fire and explosion hazards related to production facilities and adjacent developments, both shale gas specific and involving public space.

9.3.3.3 Pipelines

Pipelines comprise in-field gathering lines and transmission pipelines. Pipelines are typically shale gas specific infrastructure. In-field gathering lines are temporary pipeline systems whereas transmission lines could become part of a permanent public gas transport grid and due consideration of such options should be taken into account during the design phase.

Design and construction of pipelines shall, at a minimum, cover the following:

- compliance with relevant applicable standards
- route selection shall as far as reasonably practicable avoid vulnerable areas
- spill containment system to be installed along pipelines in vulnerable areas
- if buried pipelines are to be used, leak detection and protection systems shall be installed (asset integrity)
- the consequences of potential line failure shall be assessed
- the potential future use of land area or pipeline systems, for e.g., foundations as required for compression stations for gathering lines and transmission lines.

9.3.3.4 Infrastructure for restriction of public access

Infrastructure for restriction of public access shall be established, and shall include but not be limited to restricting access to:

- water wells or water sources
- major access roads
- well pads
- processing facilities
- storage facilities

— transport infrastructure, for instance control with inbound and outbound traffic and transport.

Restrictions of public access shall be regulated according to the change in the requirements and risks in the given phases of the shale gas activities. The risk related to organised forced entry shall be included in the assessment.

See also 9.2.4.7.

9.3.4 Shared infrastructure

Shared infrastructure includes all types of infrastructure that the shale gas development may share with other owners and users.

Shared infrastructure may include all categories mentioned in 9.3.2.

Owners and users of existing infrastructure may be stakeholders for which public engagement recommendations apply (see Sec.10).

9.3.4.1 Transport infrastructure

Transport infrastructure to enable development and production operation shall take due consideration of the loads from transport units, volumes of equipment and material transported and distances transported, over the life time of the project.

Selection of transport modes shall be assessed with respect to the capability and capacity of existing transport infrastructure, required upgrading of existing infrastructure and requirements for new infrastructure to provide suitable capacity and capability.

The transport infrastructure may comprise:

- roads
- railroad tracks
- waterway systems
- landing facilities for air-borne transport
- terminals for trans-loading and storage.

Use of transport modes shall be assessed based upon demand for transport services derived from logistics requirements.

In the selection of transport mode, due consideration shall be taken to the impact of volumes and relative changes in traffic impact on existing transport infrastructure due to shale gas activities.

For large volumes of long distance heavy transport, for instance of sand, consideration shall be given to the opportunity for using railroad or seaborne/waterway transport modes, in combination with terminals to establish a multi-modal transport system minimizing exposure of other traffic to shale gas development related traffic.

Existing transport infrastructure shall be utilized as far as reasonably practicable.

Consideration shall be given to the possibility of utilizing terminals to design effective multi-modal transport chains when seeking to utilize existing transport infrastructure to the optimal extent.

All new transport infrastructure shall be developed consistent with an impact assessment, including the EIA.

A study shall be performed to check the physical capability and capacity of transport infrastructure to accommodate transport units of equipment and material into the development area, given limitations on loads or other physical restrictions such as width, length or height.

Temporary transport infrastructure shall be designed to provide load and volume capacity to avoid logistics problems in operations due to bottlenecks or periodically unavailable infrastructure.

A study of options for collaboration concerning upgrading existing transport infrastructure or development of new infrastructure should be made. This is especially important and relevant for permanent transport infrastructure.

A review of environmental impacts shall be conducted for the route selection and alignment of transport infrastructure. The impact assessment shall be cognizant of its effects on logistics operations.

Mitigating measures, both in the design of and operation of the transport infrastructure shall be documented.

Parking/staging areas for trucks and trailers shall be developed as part of the transport infrastructure.

The use of primitive or non-constructed roads shall be assessed.

An optimization study of transport infrastructure and logistics may be used for more transparent treatment of multi-criteria evaluation. Due consideration shall be given to the criteria and impacts from transport infrastructure development versus logistics criteria and impacts.

9.3.4.2 Energy supply

Energy supply infrastructure may include, but not be limited to:

- infrastructure required to access the public power grid and infrastructure to distribute power at the shale gas site
- infrastructure for supply, storage, production and distribution of thermal power production
- infrastructure for supply, storage, distribution and tanking of fossil fuels.

Energy supply infrastructure shall meet requirements for use in, but not necessarily be limited to:

- development of site and infrastructure
- production equipment and production processes
- processing facilities
- other operational facilities
- housing, personnel and emergency services.

Energy supply infrastructure shall, as far as reasonably practicable, be routed and constructed along corridors for other infrastructure such as roads and pipelines.

9.3.4.3 *Water infrastructure*

Water infrastructure covers all infrastructure required for the supply of water to shale gas development areas. Water infrastructure includes, but is not limited to infrastructure at or for the issues addressed in 8.2.

Infrastructure options for the sourcing of water from existing wells, or the upgrading of existing water wells, shall be explored and documented.

Requirements for infrastructure development or upgrading at the water sources and for water withdrawal shall be documented for each development option.

The impact of infrastructure development on water transport shall be assessed as part of the selection of water source.

Options for water transport from the water source may include, but are not limited to the following:

- a pipeline from the water source to the well pad
- a pipeline from the water source to a central shale gas area water storage, with trucking or flexible water pipelines from the central water storage to the well pads
- trucks with water tank from the water source to the well pad
- truck with water tank to a central water storage, with flexible water pipeline from central storage to the well pads.

For further water transport and storage issues, see [Sec.8](#).

If tanker trucks are used, the required parking space shall be taken into account for sizing of the well pad areas.

Pipelines for water transport should be routed alongside corridor for other infrastructure in order to minimize additional surface impact of water transport infrastructure.

9.3.4.4 *Storage hubs*

Storage hubs centrally located on site should be, if it improves the utilisation of the development without adding risk or other adverse effects, shared with, or accessible for, other users.

Well pad local storage should be used to minimize traffic within the shale gas development area.

The storage infrastructure may include, but not be limited to:

- warehouses
- closed tanks
- open pits
- pads for movable storages including, but not limited to:
 - storage containers for all types of cargo or equipment
 - pallet sized tank or open storage units.

All storage areas shall, as far as reasonably practicable, have spill containment and guiding systems.

Storage area design shall consider the capacity and capability to store a variety of products and by-products including, but not limited to:

- fresh water
- sand
- chemicals – tanks within secondary containment
- spares and consumables
- energy
- produced water
- produced solid waste.

9.3.4.5 Housing and personnel facilities

Requirement for temporary or permanent facilities for housing of personnel and other personnel related services shall be assessed.

The opportunity for collaboration with other stakeholders in developing housing and other personnel related infrastructure shall be assessed, including but not limited to:

- renting housing and personnel services infrastructure off-site
- developing housing and personnel services infrastructure off-site.

9.3.4.6 Emergency services

Infrastructure for a first line of emergency services shall be developed on-site. Emergency services may include, but not necessarily be limited to:

- fire-fighting vehicle/equipment
- storage of fire-fighting consumables
- ambulance access area
- security.

On-site emergency response infrastructure and resources shall be balanced against access to support from a second line of emergency resources external to the site, based on response time and response capacity from the second line of emergency response resources.

9.3.5 Use of land, site abandonment and land restoration

9.3.5.1 Use of land

The operator shall develop a surface/land use plan that documents how efficient use of land is balanced against protection of vulnerable land areas to minimize disturbance of the land surface, including what efforts are being used to mitigate inevitable impacts.

All required infrastructure development shall seek to minimize the use of surface land, although this shall be balanced against logistics so that impacts from required logistics will not outweigh the benefits of land-use minimization.

Use of land shall be based upon mutual agreements with the owner of surface rights.

Abandonment and restoration of land shall be planned and executed to bring the land back to pre-development status or as in agreement with relevant stakeholders.

Before abandonment, dismantling and removal of infrastructure as a whole and in parts, it shall be emptied, cleaned, treated and protected in a proper way in order to remove potential sources of spills.

9.3.5.2 Temporary abandonment and land restoration

Temporary abandonment may be done when the infrastructure has future usefulness, and when temporary abandonment would reduce adverse impacts from the infrastructure. Temporary abandonment requires that the infrastructure is maintained to specific standards.

Temporary land restoration should be done when such restoration would improve alternative use of land, and not contribute to unacceptable risk.

9.3.5.3 Partial abandonment and land restoration

Partial abandonment shall be done when specific parts of infrastructure have no further usefulness for the shale gas activities or other purposes, but would benefit some stakeholders without undue adverse impact for other stakeholders.

Partial land restoration shall be done when the benefits of such restoration outweigh additional efforts, and do not increase overall risk.

Partial restoration of land used for well-pad after drilling and commissioning should be evaluated on a case-by-case basis dependent on requirements for area-space and load bearing capacity of the well pad for well stimulation operations.

When production from wells at a given well pad is completed the well pad shall be de-constructed and removed, and the land restored.

9.3.5.4 Permanent abandonment and land restoration

Permanent abandonment shall be done when the infrastructure has no further usefulness for shale gas activities or for other defined, accepted and desired use of the infrastructure.

Permanent land restoration shall be done when infrastructure on the land area is abandoned and removed and the further usefulness of the land requires permanent restoration of land used.

Independent of the type of abandoned infrastructure, the land shall be restored to conditions similar to the

adjacent area or as agreed with the landowner.

Any remaining infrastructure shall have a planned use in its own right.

The remaining infrastructure, whether visible on the surface, in the subsurface or in the ground, shall be properly secured so as not to be at risk for other use of the land, and marked properly both in the local physical space and as required and appropriate on relevant maps.

Final abandonment is completed when all infrastructure in soil, on the surface and above the surface is removed as far as reasonably practicable and the land used restored, including re-vegetation, and according to contractual commitments and/or as agreed with landowners.

9.3.6 Infrastructure analysis and monitoring

9.3.6.1 Analysis

All development shall seek to utilize existing infrastructure and logistics operations to the greatest extent feasible.

Analyses shall address and make transparent how contradictory or conflicting measures or objectives have been treated in the decision-making part of the development process, for instance how impacts from alternative infrastructure development are weighed against corresponding logistics impacts.

Analyses shall comprise all life-cycle phases from pre-development until abandonment and land restoration is completed.

9.3.6.2 Infrastructure versus logistics

A shale gas development can have several alternative infrastructure development alternatives. The different alternatives can also involve different logistics requirements. Movable infrastructure with increased logistics support could be used as an alternative to fixed infrastructure.

A balanced assessment of infrastructure development and the related logistics operation on the infrastructure should be performed.

The operator shall assess and document alternative infrastructure development scenarios including the corresponding logistics requirements.

The operator shall secure that all analyses related to infrastructure development and related logistics are transparent and based on acknowledged methods, linking assumptions, criteria, assessments and conclusions.

Methods for multi-criteria and multi-objective assessment shall be applied, and input parameters and results presented in a transparent way. Infrastructure development should be adapted to the estimated life-time of the shale gas project, and hence the estimated required life-time of the infrastructure.

9.3.6.3 Baseline survey

The operator shall document a baseline survey of present property, land use and infrastructure within and adjacent to the shale gas development area, which should serve as a basis for comparison with required infrastructure development for the specific shale gas development, and as a comparison with the status after abandonment and restoration of land.

The infrastructure baseline study should document available infrastructure as a basis to assess and document any requirement for development of new infrastructure for the shale gas development.

9.3.6.4 Measures

The development of infrastructure and logistics operations should be measured based on absolute measures and relative measures. The measures shall have relevance in use and as a point for comparison with the baseline survey.

Absolute measures are related to absolute quantities that will be used in the development, for instance but not limited to:

- length and width of new road development
- number of well pads
- length of gathering lines.

Relative measures may relate the absolute quantities to other characteristics of the development, for instance area covered, other infrastructure units, the amount of energy produced, or other characteristics, e.g.:

- length of road per well pad
- number of well pads per square area of permit
- number of wells per well pad
- length of gathering lines per well pad
- transport work per well pad
- transport work per kWh produced.

Measures related to the pace and scale of the development may be used, where the two may be defined as:

- pace – the time frame within which the gas extraction takes place
- scale – the number of wells drilled annually within a given development permit area.

9.3.6.5 Monitoring

A monitoring scheme covering relevant parameters shall be developed. The monitoring scheme shall apply a life-cycle approach. The life-cycle shall comprise the pre-status of infrastructure in the specific area, i.e., the baseline survey, the status of infrastructure during development and operation, including the relative progress/roll-out of the development and operation and partial land restoration, and finally the status after abandonment and land restoration.

All monitoring of infrastructure developments and use should be measured relative to the baseline survey. Equivalent measures including those used in the baseline survey should be applied.

10 Public Engagement and Stakeholder Communication

10.1 Introduction

Public acceptance is key to successful development and operation of shale gas exploration and production activities, as well as to an effective permitting process, especially in regions where shale gas production is not a mature industry. Given the current understanding and acceptance of the public towards shale gas technology, it is considered crucial for operators to engage the general public early, frequently, consistently and transparently.

A pivotal part of such engagements is the task of communicating and informing the public about the risks related to shale gas activities. Whereas analysts and risk experts tend to employ structured risk assessments to methodically evaluate hazards, the majority of citizens rely on intuitive risk judgement, or ‘risk perception’, which may be defined as;

- people’s beliefs, attitudes, judgements and feelings, as well as the wider cultural and social dispositions they adopt towards hazards and their benefits.

Risks may be amplified through social mechanisms. An accident may be followed by relatively little societal disturbance if it occurs as part of a familiar and well-understood system. However, a small incident in an unfamiliar system may be greatly amplified if interpreted as a signpost to future hazards that could possibly endanger later generations. These small accidents or incidents within unfamiliar systems are likely to be highly publicised. Hence, the public’s decisions about risk tend to be not technical, but value decisions.

This supports the need for a systematic, knowledge-based approach when working to develop public awareness about the threats and opportunities of shale gas developments and production.

10.2 Recommended practices

10.2.1 Integrate public outreach into project management

- Define and organise public outreach as an integral part of top project management.
- Ensure close cooperation between project resources and corporate/mother company communication/PR personnel, particularly for developing a strategy for and maintaining contact with mass media.
- By including outreach in the critical path of a shale gas project, outreach activities will be more effective, in sync with other key project stages, and beneficial to the overall project.
- A key component of integrating public outreach with project management is building in the time necessary to accomplish the various steps in advance of engaging the public.

10.2.2 Establish a strong outreach team

- Establish a multi-disciplinary team and include communication/community relations specialists who are able to cooperate with project technical staff to absorb the technical knowledge and thereby being able to provide sound information to all stakeholders.
- Identify spokespeople.
- Ensure consistent communication and information.

10.2.3 Identify key stakeholders

- Stakeholders typically include:
 - authorities/regulators at national, state/province and local levels
 - politicians at national, state/province and local levels
 - local communities, including local business interests, educators, senior citizen groups etc.
 - landowners and neighbours

- NGO's
- research and academia
- contractors and suppliers
- finance and insurance
- project owners/sponsors
- project and corporate/parent company staff
- the press and broadcasters.

- Map and analyse stakeholders' attitudes toward shale gas and the project at hand, and their influence.
- Identify the stakeholders to focus on in the various phases of the project life-cycle.

10.2.4 Conduct and apply social characterisation

- Social characterisation is the process of collecting and incorporating information about stakeholder views and about socio-economic, political and cultural characteristics of a particular community or area.
- It helps to understand the local community context, its perceptions and concerns, and thereby non-technical risks in site identification.
- Results provide input to the outreach strategy and social impact assessment.

10.2.5 Develop an outreach strategy and communication plan

- Develop a public awareness and consultation strategy.
- Schedule communication and consultation activities.
- Address crisis communication.
- The communication plan should include both internal and external stakeholders.
- An outreach strategy may enable the outreach team to develop an approach to public outreach that allows stakeholders and themselves to:
 - learn how shale gas production works
 - learn about the shale gas project in their area early in its development, how it will be conducted and how the operator intends to manage the risks associated with it
 - express their views to the project team
 - form relationships with project team members
 - proactively and constructively address stakeholder concerns
 - monitor the success of outreach activities and events.

10.2.6 Develop key messages

- Explain the significance of shale gas in the context of energy supply security.
- Explain the significance of shale gas in the context of national and local economics.
- Outline potential non-economic costs and benefits to the community.
- Explain the significance of shale gas in the context of its CO₂ footprint.
- Provide information on standard practices used to manage (reduce, mitigate) risks.
- Explain the role of authorities and regulators in overseeing/regulating the project.
- The messenger is at least as important as the message: engage neutral and trustworthy persons/organisations.

10.2.7 Develop outreach material tailored to the audience

- Different stakeholder groups have different issues and concerns. Outreach material should reflect this.
- Ensure that outreach material is all unbiased and accurate. Incorrect and missing information may erode credibility.
- The amount of information and level of technical detail provided must be tailored to match the audience's degree of interest, education, and time constraints.
- Any concerns that have been identified, including perceived risks, should be addressed in language and formats suited to the intended audiences.

10.2.8 Actively oversee and manage the outreach throughout the life of the shale gas project

- Outreach programs should be actively managed to ensure that consistent messages are being communicated and that requests for information are fulfilled. The identification of an outreach leader or coordinator to manage, coordinate, and direct outreach may be crucial for project success.
- As a project unfolds, public perception will be influenced by the extent to which the project and the project team are well coordinated and responsive.
- Pro-active engagement can contribute to a sense of project openness and transparency
- Management of the outreach program should evolve over time to meet the differing needs of each phase of a shale gas project.
- Frequent communication amongst the outreach team and the rest of the project team helps to ensure consistency and assure that emerging concerns are addressed.

- Effective outreach activities may involve significant interaction with stakeholders both as a means of conveying technical information about the project and also as a means for the project team to obtain invaluable information about the community's views and concerns about the project during its development.
- During the operation phase, sharing information on the progress and results can serve to keep stakeholders engaged.

10.2.9 Monitor the performance of the program and changes in public perceptions and concerns

- Monitoring the performance of the outreach program allows the project team to stay abreast of how the community perceives the project and gauge the effectiveness of the outreach activities. Monitoring can also help identify any misconceptions about the project and develop outreach strategies to correct them.
- Monitoring can be accomplished through informal telephone calls and/or routine interviews with key stakeholders both within the local host organisation and in the community. The tone of coverage in local media can also provide a source of information, and the same is true of social media (e.g., blogs, Twitter, and Facebook). In addition, websites that discuss the project could be informative and provide a platform for public interaction on a more spontaneous basis.
- Outreach program monitoring also takes into account changes in local conditions, such as economic fluctuation or other significant impacts, which may influence the perception of a shale gas project.

10.2.10 Be flexible and refine the outreach program as warranted

- The outreach team must be ready to adapt to changes in information about the site, unexpected events, and other conditions that may have a strong influence on the public's perception of shale gas production during project implementation.
- Feedback from monitoring should be used to improve project performance by making necessary operational changes. Likewise, developing processes to collect, analyse, and respond to feedback gathered through outreach can be used to continually improve the overall performance of the project and the outreach team.
- External outreach processes and materials, as well as communications within the project organisation should be updated as needed to reflect project progress, lessons learned, and communication improvements identified through target audience feedback.
- If a case arises where some concerns cannot be addressed, the communications materials should explain why.

11 Permitting

11.1 Introduction

Shale gas projects are located in different countries/states/provinces with different legal and regulatory systems and traditions. Hence projects are carried out in different legal and regulatory environments. The environment is also heavily influenced by the political attitude towards shale gas, which is interlinked with public awareness and/or acceptance of shale gas.

As a consequence of the above, the terminology used in this document may not be congruent with the terminology of any particular country/state/province.

In a number of jurisdictions with shale gas resources, efficient and effective legislation may not be in place. Until suitable legislation is in place, industry and regulators will have to relate to a regulatory regime developed with other direct purposes in mind, either as-is or to a varying degree adapted to shale gas conditions.

In this context it is essential that operators take an active role in communicating their needs to the regulators and discussing regulatory approaches and the need for documentation in the permits. To some degree, operators may have to contribute to building competence among the regulators.

There is a strong link between permitting processes and public awareness/acceptance of shale gas. Lack of public acceptance for shale gas development may delay a shale gas operation, or even entirely prevent its permitting. The link between successful permitting and public engagement will influence the consultation processes that have to be carried out by the operator.

The main challenges related to permitting of shale gas activities are:

- public engagement/acceptance influencing the permitting process
- communication with regulators and stakeholders during the permitting process
- the existence of several levels of authority bodies (national, regional and local) which may have different viewpoints on shale gas
- an absence of legislation for shale gas specific aspects
- the risk of litigation with landowners, and potentially with other stakeholders (lengthy and costly court proceedings).

11.2 Recommended practices

- operators should ensure that all potential stakeholders are heard and communicated with
- the local community has substantial influence on the permitting process and should be properly consulted early in the project development
- operators should ensure continuity of key people in the organisational structure. This is important for keeping continuity in the interaction with regulators and stakeholders throughout the permitting process
- during the permitting process and in particular when handling public consultations, it is important to remember the holistic approach: operators should ensure that plans are broader than just the technical issues. If stakeholders only hear a developer's preferred option, they may seek reassurance that other options have been considered and may request additional consultations. Prepare and present alternatives to stakeholders early in the project planning stages
- operators should map potential challenges and solutions to these challenges
- operators should be open, honest and flexible in dialogue with stakeholders
- operators should prepare for a longer permitting process than initially planned, while operators should seek to establish a permitting timeline/schedule, which is endorsed by the regulator as being realistic
- operators should develop a framework to facilitate discussions with landowners. Try to ascertain the status of public investment to help inform landowners
- operators should understand the permitting process as fully and as early as possible. This is critical to developing the permitting plan for the project and to carrying out an efficient permitting process
- if the region or local community has recently been exposed to other large infrastructure projects, an additional infrastructure project may meet with more resistance. The public acceptance and the permitting process for a shale gas project may be influenced by other major infrastructure projects, i.e., pipelines for other purposes, road/railway or industrial plants that have or are being carried out in the region or locally. The project developer should anticipate the potential impact on the permitting process from such developments
- operators should ensure that effective knowledge management processes are established. It is important that procedures and agreements are known and available for examination during the life-time of the project
- through active communication with regulators the need for further research and analysis may be identified at an early stage
- operators should make sure that permit applications and supporting documentation presented to the regulators are complete, well structured (easy to understand) and consistent. This is to ensure an efficient permitting process. Different regulators within a country may have different requirements for permit documentation. Early and open communication with regulators on these issues will help the operator to understand the expectations and needs of the regulators and thus avoid delays in the granting of permits due to lack of documentation or clarity in submitted documents
- public acceptance of shale gas development will influence the permitting process, so there should be close cooperation between the operator's permitting team and public outreach team
- operators should identify and communicate project benefits to the local communities. It is important for the operator to understand what kinds of benefits are expected by the local community
- operators should undertake analysis of previous public acceptance issues locally, regionally and nationally to anticipate possible challenging issues.

APPENDIX A DNV RISK MANAGEMENT FRAMEWORK (CONSISTENT WITH ISO 31000)

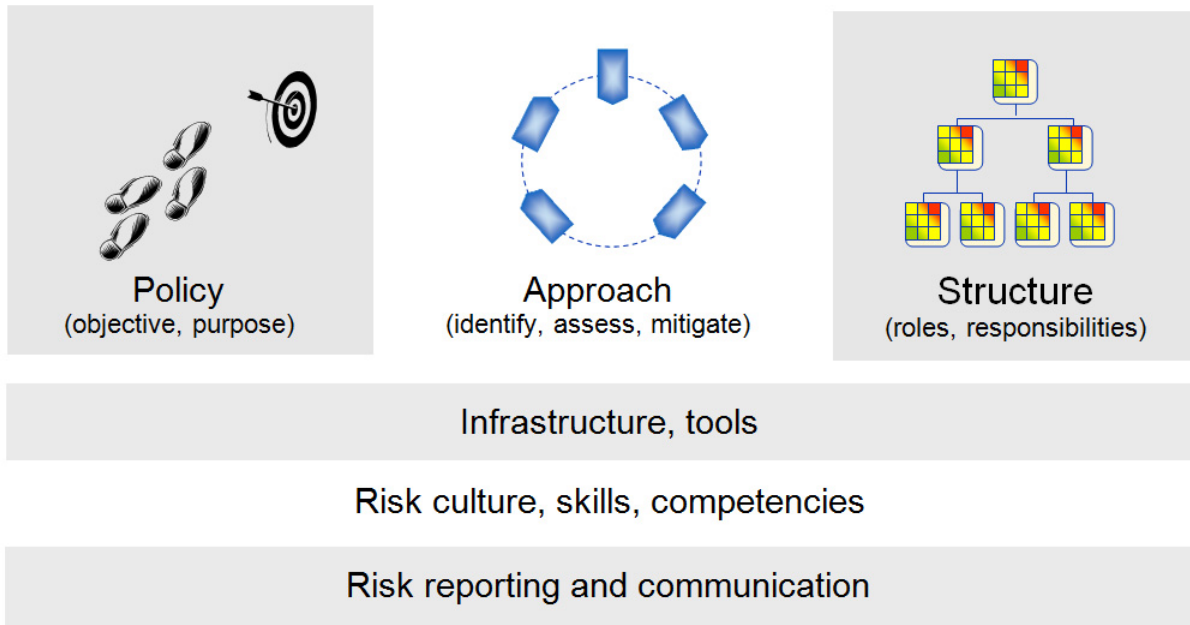


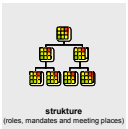


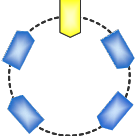
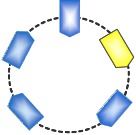
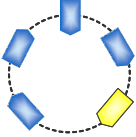
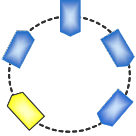
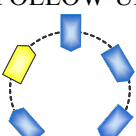








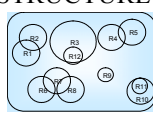




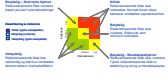





Table A-1 LEVEL 0 - FRAMEWORK	
<i>STEP</i>	<i>PURPOSE</i>
POLICY  <small>policy (goal, strategy, acceptance criteria)</small>	Outlines WHAT principles and guidelines that are to be followed when working with risk management. Ensures uniformed rules and criterias for risk management.
APPROACH  <small>approach (work process and method)</small>	HOW the risk management shall be implemented as to methodology. Which risk management approach shall be applied? This will ensure a systematic and uniformed approach.
STRUCTURE  <small>structure (roles, mandates and meeting places)</small>	The risk management structure describes WHERE & WHO in the organisation with responsibilities for the risk management. The structure shall ensure that risk management becomes an integrated part of the daily business and thus a naturally running process.
TOOLS 	The risk management tool shall SUPPORT a high number of risk factors and give an overall view of the changes in risk exposure. This to ensure a smooth and continuous follow up of risks, risk reducing actions and risk events.
CULTURE 	A prerequisite for an EFFECTIVE risk management process is the right risk culture. A risk culture is a key success factor and must be evolved to ensure continuous risk awareness and focus.






<i>LEVEL</i>	<i>PURPOSE</i>
INITIATION 	Specify and prepare the fundament for risk management. Achieve a compromised understanding of the basis for risk management.
IDENTIFICATION 	Reveal risks that threat achievement of goals, and systematically structure the risks to ensure manageability.
ANALYSIS 	Visualize how risks (threats and weaknesses) influence goal achievement, and place responsibilities for handling and follow up of risks (risk ownership).
ACTION PLANNING 	Decide where to initiate actions and develop an action plan to ensure efficient handling of risk factors.
IMPLEMENTATION AND FOLLOW-UP 	Ensure effective implementation of action plans, continuous follow up on risk picture, periodical update of risk picture, and reporting of risk- and action status.

<i>AKTIVITET</i>	<i>PURPOSE of the activity</i>
METHOD 	Find an appropriate method for risk analysis.
GOAL 	Identify, develop and describe the goals relevant for risk management.
SCALES 	Set probability and consequence scale to ensure uniformed evaluation of risk level.
VALUE CHAIN 	Identify which processes and activities that are within scope for risk evaluation.
CATEGORIES 	Establish risk categories (sources/causes of risks) to ensure a structured and systematic risk identification.
GUIDE 	Develop risk questioning guide to ensure that all relevant aspects are included for a systematic identification.

<i>ACTIVITY</i>	<i>PURPOSE of the activity</i>
IDENTIFY 	Identify threats and weaknesses of importance to the risk management goal(s).
DESCRIBE 	Compose good names and precise descriptions of risks to ensure effective communication and handling.
STRUCTURE 	Reach a collection of risks which are mutual exclusive, and formulated at the same level of detail.
<i>ACTIVITY</i>	<i>PURPOSE of the activity</i>
IDENTIFY 	Identify threats and weaknesses of importance to the risk management goal(s).
DESCRIBE 	Compose good names and precise descriptions of risks to ensure effective communication and handling.

<i>ACTIVITY</i>	<i>PURPOSE of the activity</i>
ANALYSE RISKS 	Decide risk level (probability x consequence towards risk management goal) for identified risks in order to differentiate between critical, significant, and negligible risks.
APPOINT RISK OWNER 	Attach each risk to a responsible organisational unit and a risk owner (person/role) in the unit.
PRIORITIZE RISKS 	Prioritize which risks to be treated with actions.

<i>ACTIVITY</i>	<i>PURPOSE of the activity</i>
IDENTIFY ACTIONS 	Find reasonable risk reducing actions for the prioritized risks.
ANALYSE AND DECIDE ON ACTIONS 	Prioritize which actions to be implemented based on evaluation of their risk reducing effect. Also to define potential risks where no adequate treatments are found, and that therefore need to be accepted.
APPOINT ACTION RESPONSIBLE 	Locate the person in the organisation that is given the responsibility of completing the action.
DEVELOP ACTION PLAN	Establish a detailed plan for implementation of the actions.

<i>ACTIVITY</i>	<i>PURPOSE of the activity</i>
IMPLEMENT ACTION AND UPDATE RISK LEVEL 	Implement the planned actions, investigate whether the actions are successful, and possibly initiate new actions.
DETERMINE STATUS 	Determine status for risks and actions after the implementation.
MONITOR RISK PICTURE 	Continuously identify risks that have been left out or identify new risks that arise from changed circumstances in own organisation or the surroundings.
UPDATE RISK PICTURE PERIODICALLY 	Periodically updating the risk picture by carrying out a systematic identification and analysis of new risks, re-evaluating the current risks.
REPORT STATUS 	Report important risks and actions to the management group.

APPENDIX B

RISKS TO THIRD PARTIES

B.1 Introduction

In assessing risks to third parties it is helpful to divide the shale gas activity into its component parts. These have different risk profiles with respect to third parties.

- Development of the well pad and drilling the well
- Gas gathering and booster facilities
- Gas processing plants – gas compression, condensate export, H₂S removal

Generally gas and condensate activities lead to conventional, well understood, and relatively modest risks to third parties. However H₂S risks and an emerging trend to use LNG fuelled rigs are potentially larger risks to third parties.

Safety risks to third parties:

- Vehicle transportation risks – large numbers of heavy vehicles on narrow rural roads
- Personal safety risks due to environmental contamination, noise, etc.
- Process safety risks – fire, explosion and toxic release of well fluids at the well pad, associated with gathering pipelines, at the gas processing plant, from cross country pipelines and condensate transport vehicles, and LNG leaks from LNG powered generators.

The focus of this section is on process safety risks.

B.2 Process Safety Risks at the Well Pad

The well pad is mostly conventional in its activities and most process safety risks are well regulated. This applies to well design, blowout preventers, and storage tanks for flashing fluids. Shale gas facilities sometimes have condensate and pose relatively low process safety risks – mainly from pool fire rather than jet fire or vapour cloud explosion.

A risk during shale gas drilling may be a blowout event. In general terms, blowout risks would be expected to be less than in a normal well as the purpose of hydraulic fracturing is to release otherwise “tightly bound” gas and associated liquids. However, isolated pockets of shallow gas or untapped hydrocarbons might be encountered and hence blowout is always a risk. This is a fire risk locally if ignition is quick, a vapour cloud risk if ignition is delayed, or a toxic risk if there is significant hydrogen sulphide content. One risk reducing factor is that most shale gas well fluids will be positively buoyant. Methane is very buoyant (MW=16), but additional condensate and H₂S content can increase the molecular weight to closer to that of air (MW=29) and that can lead to large vapour cloud events, which do cause third party risks.

Facilities should assess the likely maximum MW of well fluids and if these can approach ambient air density or have significant H₂S content then suitable discharge and dispersion calculations to safe concentrations should be carried out (EPA Risk Management Plan end-points, for example, are cloud or jet LFL, toxic H₂S ERPG2 concentration – 30ppm, and vapour cloud 1psi overpressure or 5kW/m² thermal impact). These are not exclusion zones but they must be communicated to the local community and considered in any emergency plan. An important objective is to assess possible risk reduction strategies for any event that could give rise to third party impact. DNV notes the very significant event at Gaoqiao in China in 2003 (233 fatalities and 9000 injured associated with a sour gas well blowout event at night into very calm air that as it was dense sat on the ground over a nearby village). This was not a shale gas well, but it does highlight the fact that third party risks do exist especially for H₂S containing well fluids which are dense or neutrally buoyant.

Blowout risks should assess the adequacy of the BOP. Substantial extra requirements have been introduced by US regulators after Macondo, but these are for offshore wells. A finding of the DNV Forensic Investigation for the Dept of Justice was that the BOP design at Macondo was exactly that – a Blowout Preventer; it was not a Blowout Arrester. If the drilling crew fails to recognize the blowout event during its early phase, it is possible that the BOP will not function to stop the flow. DNV recommended that the BOP design be verified as functioning adequately both before and during a full blowout event. As noted before, the likelihood and size of any blowout is likely to be much smaller for onshore hydraulic fracturing wells than for normal drilling activities into formations in more porous media.

Condensate storage tanks on the well pad are a safety risk, but are usually well covered by current regulations. These may involve a “live” condensate – that is one with some significant vapour pressure, but it is unlikely to flash significantly if leaked. This reduces any vapour cloud hazard to third parties. Operators should assess whether any onsite condensate will be stored in conditions where a significant flash might occur and thus lead to a drifting vapour cloud that might affect third parties. If this is the case then some consequence calculations should be carried out for realistic spill or leak events. The end-points for those calculations should follow guidelines from the USA EPA Risk Management Plan shown above. If the condensate does not flash significantly, then it is primarily a pool fire risk and existing regulations address those hazards well and prevent

any off-pad third party risks.

A newer risk at well pads is the introduction of liquefied natural gas (LNG) as a fuel to power the drilling activities instead of conventional diesel fuel. This is currently less expensive and cleaner – a recent paper estimates LNG results in 30% fewer emissions. Since shale gas wells are under pressure to enhance their environmental performance, it is quite likely that there may be many additional LNG installations.



Ensign Energy has reported to its shareholders that natural gas powered rigs reduce fuel costs while reducing emissions by 30 percent. In this photo, an LNG vaporizer and three tanker trailers can be seen in the foreground. Photo courtesy of Ensign Energy.

Figure B-1
LNG Fuelled Drilling Rig

LNG fuelled rigs lead to two types of third party risks that need to be assessed. These are transportation risk associated with multiple truck loads of LNG cargoes. While these trucks will comply with local regulations, these will typically all be sourced from one LNG supplier with a significantly longer transportation route than comparable diesel fuels. However, to the nearby community the traffic risk will be about the same. LNG fuel is maintained near to atmospheric pressure and thus would not be affected by regulations related to flashing liquid storage tanks at well pads in the USA. However LNG does pose third party risks from a leak as the methane gas although inherently buoyant (MW=16) is dense due to the very low storage temperature (around -160°C). Current DOT regulations require an exclusion zone around an LNG production facility of 10 minute release at full pump flow. However a well pad is a consumer site and not subject to such regulations. DNV recommends that selected parts of NFPA 59A be applied to facilities with LNG fuel. This includes a spill capture system to direct design LNG spills away from local hazards and direct these to an impoundment where boiloff will occur at restricted rates and at safe concentrations. A properly designed impoundment can essentially eliminate third party risks, although not risks to the well pad zone itself. A flammable gas detection system should be installed with alarms and with a local illuminated wind sock so that staff can quickly assess the direction of any vapour cloud travel in day or night conditions so they can escape in a safe direction.

A rare event is the Bleve of a transport LNG truck. In theory, these should not be Bleve candidates, but a Bleve did occur near Tivissa, Spain in 2002. This was because the PRV was set to 8bar, which was appropriate for the pressure vessel used, but not for the LNG cargo. The effect was to allow the near atmospheric pressure LNG to be raised to 8bar by a fire after the accident, in which the LNG truck rolled over. Pressurized LNG acts like any other pressurized hydrocarbon: – a Bleve becomes possible and will occur when the external fire raises the temperature of the unwetted steel shell to a point where it weakens sufficiently to fail due to the internal tank pressure. The sudden release gives rise to a large near instantaneous fireball that can be a major risk to people within a few hundred meters. The relief valve set point should be confirmed as suitable to avoid this type of incident.

B.3 Pipeline Risks

Shale gas facilities are typically part of a network and rather than process raw gas on each pad, it is common to employ a gas gathering system and send the gas to a central gas processing facility where final separation of gas and liquids is achieved, H₂S is removed if present, and gas is conditioned to be suitable to inject into the main gas transmission system.

The gas gathering pipelines can be quite variable. Often the pressure is relatively low compared to transmission line pressures of 1200 psi, and the pipelines are normally but not always buried. In most cases, the gas will be buoyant so leaks tend to have only local effects. If the cause is mechanical digging or farming activity, this can

cause local third party impact, and it would be rare for there to be any longer distance impacts. Such pipes are subject to current regulations and these are generally regarded as sufficient.

Transmission lines from the gas processing plant are covered in the USA by PHMSA, a part of the Department of Transportation. These are generally considered effective.

There have been some gas pipeline accidents in recent years, but these affected large transmission lines with older installations where mechanical integrity had been allowed to degrade. Shale gas installations should be new and mechanical integrity should be good and verified by a hydrostatic test at installation. A full installation integrity program should be implemented for welding competence and procedures, coating and depth of cover. An effective ongoing corrosion protection and mechanical integrity program should cover all pipelines – both gathering and transmission lines.

B.4 Gas Processing Plant Risk

These facilities are often remote from the shale gas drilling pads. However they are part of the system and can have third party risks. The most common risk is due to high pressure gas handling and condensate storage and export. These are routine hydrocarbon risks and third party impacts should be low. The largest risk, if present in the source shale gas, may be due to H₂S removal.

Gas risks to third parties are likely to be small as the gas is buoyant and would quickly disperse upwards. If a gas leak were ignited, then there would be a localized jet fire and this would be serious for the pad itself but unlikely to cause third party damage. An unignited buoyant gas jet should not lead to a ground level vapour cloud and hence there appears little potential for vapour cloud explosion.

H₂S removal (where this is a significant component, e.g., US Rocky mountain area) could give rise to large volumes of nearly pure H₂S if there was a serious loss of containment event. H₂S would normally pass to a sulphur plant for treatment and conversion to pure sulphur. These plants rarely pose significant offsite risks and the main risk would be associated with a leak of the H₂S line feeding the sulphur plant. This could be a major risk to offsite populations as the release would be concentrated H₂S and dense. This would require a full HAZID and risk assessment if there were vulnerable populations nearby.

DNV recommends a HAZID to properly identify any significant risks. Processing will raise gas pressures to transmission pipeline pressure, typically 1200 psi or higher, and leaks can be therefore large. Gas processing plants typically may fall below the inventory thresholds to be captured within the OSHA 1910.119 Process Safety Management regulations or the EPA Risk Management Plan regulations. However, if there is a significant H₂S inventory due to treatment processing then they may fall under these regulations. These identify a wide range of hazard identification, risk management and process safety management programs. Such programs are beneficial to normal operations and should, in principle, be applied to all gas processing plants, not just those for large toxic inventories.

B.5 Summary

Third party risks from shale gas operations are likely to be small, both due to the remote siting of such facilities and the generally low risks due to handling buoyant natural gas and low pressure condensates. H₂S and LNG used for fuel do introduce the potential for offsite harm to third parties. If present, these should be assessed properly. Pipeline risks are low if a good mechanical integrity program is implemented and the lines conform to the suitable regulations (e.g., PHMSA in the USA). The largest specific risk might be associated with the gas processing plant in case of a release of high concentration H₂S being sent to a sulphur plant for safe removal.