Final Technical Report on evaluation of existing assessment methodologies and the proposed common methodology for pan-EU assessment

Deliverable T2b
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2. Introduction
Over the last decade, various national assessments of shale gas and shale oil resources for EU-countries have been published. Due to different and/or undocumented methodologies, fundamental assumptions and quality and quantity of underlying geological information, the results of these national assessments are not always easily comparable and interpretable. This report focusses on the development and definition of a uniform methodology for estimating (in-place) shale gas and shale oil resources at the pan-European level. The methodology is compared with existing published assessments in order to analyse differences and similarities with the various other methods used, to better understand the variations in published estimations across Europe and to improve the overall comparability of the pan-European shale gas/oil assessments with existing studies. The methodology is established to determine estimates of GIIP (Gas Initially In Place) and OIIP (Oil Initially In Place) including associated uncertainty bandwidths originating from the various geological input parameters available. In order to discuss the TRR (Technical Recoverable Resources) within a typical shale gas development area, this report also includes an example of a simple national shale gas development plan based on available literature.
3. Review of existing EU methodologies

In the following chapter the most common methods used for shale gas/oil assessment are described and an overview is given for the most recent assessments for European shale gas/oil plays. This brief summary of publications and background information is designed to help to get an overview of the previously applied methods and their applications. The focus of this overview is on methods that can be applied in Europe and will only briefly touch those that were used in more developed shale resource areas like the US.

3.1 Existing techniques

The following section gives an overview of the different assessment techniques that have been applied to the shale gas/oil systems of Europe. These techniques can be grouped into and summarized by the common methods described below. Each of these methods relates to a different level of maturity and development of a play, reflecting what kind of data and knowledge is available to assess the resources and reserves. These methods are usually not used stand-alone but are often used in combination with each other.

Most methods can be performed using two different approaches – deterministic or probabilistic. The Deterministic approach uses single values that are considered representative for the system to estimate the result. The Probabilistic approach uses a range for each value together with a probability density function that are then combined analytically or by random sampling (e.g., Monte Carlo simulation).

Prescreening method

The Prescreening method directly compares shale gas/oil assessment units on the basis of a preselected set of parameters. Its result is a qualitative comparison of these parameters per assessment unit and it does not give a quantitative assessment of the GIIP/OIIP or TRR. In this method each parameter gets a value/number/type assigned which is weighted according to the assumed influence it has on the quality of the shale gas/oil system. The level of detail of the assessment is strongly dependent on the amount of data that is available. Parameters typically used for the prescreening method are depth, thickness, TOC, maturity, type of organic matter, gas content, mineralogy, temperature, stress state and other geomechanical parameters. As a result each assessment unit gets a total value/number/type assigned with the assumption that the units with the higher value/number/type have a higher chance of success. This method is mainly used to identify sweet spots within one system and not to compare different systems. Examples of the application of this method are published in Bammidi et al (2011) or Pitcher et al. (2012).

Analogy method

The Analogy method is an indirect approach used to estimate the total recoverable resources (TRR) or resources initially in place (GIIP/OIIP) on the basis of expert judgment and validated similarities with developed analogue shale plays. This method is particularly useful in undrilled or sparsely drilled areas where nearby and tested analogue shale plays with sufficient production data are present. As such it is widely used for undeveloped shale plays in the US.

With the Analogy method the average recovery from a single production well or a developed unit area (or alternatively the average GIIP per unit area) is determined from the well-known analogue shale play. These values are then extrapolated across the extent of the shale under investigation. This can be done in a deterministic manner (i.e. assuming a single best estimate value) or a stochastic manner (assuming
a range of possible values). It is important to note, that the assessment of the TRR/GIIP/OIIP based on the analogy method also assumes that the same production technology is used as in the analogue.

The validity of the Analogy method strongly depends on the assumption that overall conditions and geological characteristics in both areas are reasonably similar. This can only be considered when enough geological information (e.g. research wells, regional mapping) is available. Without exploration or production wells in the untested shale layer, the outcomes of the Analogy method will remain very uncertain. The confidence of the outcomes furthermore relies on the robustness of the geological parameters and production data across both areas. If these parameters are characterized by a fair amount of regional heterogeneity the validity for the entire layer or play becomes questionable.

**Volumetric method**

The volumetric method is used to calculate the total gas/oil initially in place (GIIP/OIIP) of a subsurface area based on a set of measurable rock parameters. This method is based on the assumption that the gas is stored as free gas in the pore space and adsorbed on organic matter or clays while the oil is mainly located in the pore space. In order to convert the total GIIP/OIIP to TRR an additional recovery factor is needed.

The volumetric method is mainly used for areas with only little or no production data. It uses variations of the following formula (e.g., TNO, 2009, BGR 2016):

\[
\text{GIIP} = \text{GIIP}_{\text{free}} + \text{GIIP}_{\text{adsorbed}}
\]

\[
\text{GIIP}_{\text{free}} = V \times \phi \times \text{sat} \times B_g
\]

\[
\text{GIIP}_{\text{adsorbed}} = V \times \rho \times G
\]

Where:

- \( V \): Volume, m³
- \( \phi \): Porosity, %
- \( \text{sat} \): Gas saturation, %
- \( B_g \): Gas formation volume factor, Rm³/Sm³
- \( \rho \): Rock density, g/cm³
- \( G \): Langmuir factor

The parameters necessary for the calculation of the GIIP/OIIP can be derived from detailed geological/petrophysical studies executed during exploratory drilling or from outcrop studies. For the production related parameters well testing is required. The result, uncertainty and reliability of the calculation very much depend on the quality and validity of these input parameters. To account for uncertainties related to the input parameters, this method is mainly used in a probabilistic way, while a deterministic approach can be valid in a very well-studied area.
Decline curve analysis
The decline curve analysis calculates the TRR assuming the use of current technology. This technique is applicable where actual production occurs. It is mainly used to assess the potential of a new well in an already existing production area.

For a decline curve analysis production data from nearby wells is used to predict the possible production of a new well. This can also be used in an analogue setting when it is sufficiently proven that the analogue is valid. There are different ways to analyze production data using different models and methods. Clarkson (2013) gives a detailed overview of these methods, when they should be applied and the advantages and drawbacks of the individual approaches.

Several studies have indicated that pure decline curve analysis provide too optimistic TRR estimates for shale gas/oil systems (e.g., Ilk et al. 2008). To account for some uncertainty with respect to the variability of the shale layer, a probabilistic approach may be applied to this method (e.g. Jochen and Spivey, 1996; Cheng et al. 2010_1).

Reservoir stimulation
Reservoir simulation is mainly used in conventional oil/gas assessment to calculate the TRR for individual wells in one reservoir. Only few studies on the use of reservoir simulation for unconventional resources have been published (e.g., Oudinot et al. 2005 for coalbed-methane and Schepers et al. 2009 for the Utica shale). For a successful application of the reservoir simulation method a good representative reservoir model with reservoir property information such as pressure, temperature, porosity, permeability, fluid properties as well as production data of at least one well from the system is necessary.

The overall approach is very similar to conventional reservoir simulation. A static reservoir model is built and populated with reservoir properties and their uncertainty distributions. Multiple simulations using a probabilistic approach are run for the history matching to calibrate the reservoir model to the production data from the available wells. The probabilistic approach of this method results in a probability distribution of TRR values that can be expressed in P10, P50 and P90 as well as show key input parameters that determine the TRR. Books by, e.g., Ertekin et al. (2001) and Carlson (2004) give a general description of the conventional method, for an example of reservoir simulation in a shale gas system the publication of Schepers et al. (2009) can be consulted.

This method is only applicable in areas with sufficient geological data to build a reliable reservoir model and enough production data to calibrate the history matching.

Resource triangle
The resource triangle method is based on the assumption that the hydrocarbon resource types follow a triangular distribution based on their abundance, their reservoir quality and the technology required to produce these resources successfully (Figure 3.1).

Studies where this approach was applied to the North American basins state that for every 10% of hydrocarbons in recoverable conventional resources another 90% are located in technically recoverable unconventional reservoirs (including tight reservoirs, CBM and shale gas/oil, Old et al. 2008 and Cheng et al. 2010_2).

This method also provides a value for the TRR of all unconventional resources in a basin. The result of this method is strongly dependent on the assumption that the
distribution of hydrocarbon resources in similar in different basins throughout the world.

![Resource Triangle Diagram](image)

**Figure 3.1 Resource triangle according to Masters (1979; modified after Dong et al. 2012)**

### 3.2 Selected background publications

In addition to the publications listed in the description of the possible methods a short list of overview and background publications is compiled here for additional information. These publications were selected because they provide an overview of the current state of the art as well as because they discuss and compare different shale gas/oil assessment methods.

Demirmen (2007) gives an overview of the challenges of resource assessment in general and not only for shale gas/oil assessment. The main focus is on conventional hydrocarbons and reserve estimation at the pre-production stage. The publication provides a good overview of the different methods commonly used for resource assessment as well as their advantages and disadvantages. He also describes the different sources of uncertainty that have to be addressed in reserve estimations, the technical uncertainty and the non-diminishing uncertainty. Of these the technical uncertainty is related to data availability and gets smaller with increasing knowledge of the system. The non-diminishing uncertainty addresses the fact that even with an increasing amount of information the overall uncertainty does not diminish, which is related to our inability to properly quantify uncertainty on all levels.

McGlade et al. (2013_1) compare the main methods used in the past to assess the TRR of shale gas resources. They focus on different methods and their strength and weaknesses and criticize the way uncertainty has been handled in these studies. They give suggestions how to handle the application of different methods and uncertainties.
in different settings. In combination with this publication McGlade et al. (2013_2) give an updated overview of the different assessments that were published between 2009 and 2012 worldwide and compare the different assessment results. It also gives a good introduction into the different terms that are generally used in shale gas assessment. Their main point of focus for future assessment studies is how to deal with uncertainty and the use of probabilistic methods.

In a recent publication Stueck et al. (2015) compares the approach used by the USGS for shale gas assessment, the performance based method and the volumetric approach for two well-developed shale gas basins and two frontier plays. They come to the conclusion that both methods give comparable results when the initial screening, definition of assessment units and use of geological inputs is done in a similar way.

Charpentier and Cook (2010_1, 2010_2, 2011) present the main differences, advantages and limitations of the revised assessment method of the USGS for shale gas resources and compare their revised method with the one previously used. The main addition to the method is the use of a probabilistic approach to handle uncertainty and the subdivision of the assessment area into assessment units of varying risk that is associated with them.

Selley (2012) published an overview of the state of shale gas/oil developments in the UK, comparing the proceedings with the US and providing interesting background on the history of shale gas development.

In more recent years several publications originate from China looking at different shale gas assessment techniques. For example Yuan et al. 2015 focuses mainly on the economical aspects of shale gas assessment and gives a good overview of the current state of technical-economic evaluation techniques of the last 10 years. According to Yuan et al., even though improvement can be seen, techniques are still not accurate enough to base investment ideas upon and request that additional research should go into the development of these techniques.

3.3 Previous studies in Europe

In this section an overview of the published shale gas/oil assessments for Europe is given. This section can be subdivided into the global level assessment studies, the country specific assessments mainly prepared by or in cooperation with the respective national geological surveys and the individual assessments or assessment overviews published by independent researchers.


Several studies on countrywide or local assessments were published by the respective European Geological Surveys mainly using the volumetric method. Examples are the Carboniferous Bowland Shale gas study (Andrews, 2013) and other studies by the BGS (DECC, 2010, Monaghan, 2014, Andrews, 2014); shale gas potential in Germany and the recent update (BGR 2012 and 2016); the GESSAL/ACIEP evaluation in Spain or the SGU summary reports (Erlström et al. 2014, Erlström, 2014) from Sweden. The

Weijermars (2013) looks at the economic feasibility of the five most promising European shale gas plays from Poland, Austria, Germany, Sweden and Turkey using different approaches. For all cases he uses a uniform field development plan for each play with 100 wells in total and a 25 year life cycle. A comparison with US shales as well as a discussion on the uncertainties related to these calculations and general risks with respect to legislation and public acceptance is included in the article.

One of the main outcomes of all studies looking at different assessments is that the results are very difficult to compare. The previous global studies resulted in a wide range of recoverable resources for shale gas in Europe between 2.3 and 20 Tcm (McGlade et al. 2013_2). Furthermore they did not take the specific European situation into account in their assessments and often worked only from literature data. The use of a reproducible, unified method focused on the European situation helps quantifying the shale gas/oil resources. A direct link to the individual national geological surveys (NGS) assures the use of the most up-to-date public data while the application of a fully published method ensures that the assessment results can be easily updated by the NGS in the future. Developing a method with European focus also guarantees more control of the geological selection criteria and more focus on geological and data uncertainty compared to previous studies.

In the report of work package 7 all previously published shale gas/oil estimates for the individual basins will be individually discussed against the results of this study and the main differences in the approaches highlighted.
4. Selected method

The selected method needs to fulfill several prerequisites.

- The focus of the study is on gas/oil initially in place (GIIP/OIIP) calculation; the selected method therefore needs to be able to calculate these parameters.
  - In most countries in Europe no production data is available. This excludes the assessment methods that rely on production curves for the calculation of the TRR. The use of an analogue in this case is not recommended as it is not yet clear which producing shales are adequate analogues for the European systems.

- It should address and visualize uncertainty on different scales.
  - Several methods address the uncertainty of the individual shale plays on different levels
  - The Prescreening method gives an indication how good a play is with respect to the selected screening parameters in comparison to others. Possible screening parameters can also be data availability and general uncertainty.
  - The volumetric method can be used with the probabilistic approach where ranges and probability density functions are assigned to the individual parameter. The final assessment then includes a possible range for the GIIP/OIIP as well as the importance of the individual parameters on the uncertainty.

- The method needs to be able to deal with a wide range of data availability and detail, both between the different basins but also within one basin.
  - This is realized by using the analogue method when not enough data is available for the calculation of the GIIP/OIIP. Possible analogues can be the same shale formation in another country/assessment unit or similar shales from Europe or the US.

- It should have the possibility to upscale the calculated GIIP/OIIP values to total recoverable resource (TRR) estimates
  - The GIIP/OIIP values can be converted to TRR using specific recovery factors based on customized field development plans for the individual assessment units. This needs to be done on a case to case basis and is not part of this assessment.

A combination of the probabilistic approach of the volumetric method, together with the analogue and prescreening methods meets all these prerequisites and will be used in the context of this study. So far this combination of methods has only been applied in individual European countries and not on a European wide scale. The use of different screening parameters in each study makes a comparison between countries difficult.

The proposed method for the assessment consists of four individual steps.

4.1 General uncertainties regarding the presence of shale gas/oil

In the first step the general uncertainties of the shale gas/oil play are addressed. This risk assessment uses available geological parameter and descriptions. It is based on the reports on the shale gas/oil formations supplied by the respective national geological surveys which were unified and are presented in the report of WP 4. There the following scheme is used to describe the plays basin by basin and to estimate the general risk of the presence of a shale gas/oil play.
Basic setup for the shale descriptions

**Basin Index – Basin name – Shale name**

**General information**

Table 4.1 The general information is compiled together with GEUS (Task 5 and 6)

<table>
<thead>
<tr>
<th>Index</th>
<th>Basin</th>
<th>Country</th>
<th>Shale(s)</th>
<th>Age</th>
<th>Screening-Index</th>
</tr>
</thead>
</table>

**Geographical extent (incl. map if available)**

A brief description of the geographical extent of the basin and the described shale layers within.

**Geological evolution and structural setting**

**Syndepositional**

A brief description of the syndepositional geological evolution at the time of the deposition of the shale layers. In this part the following questions are answered: What is the lateral continuity of the shale? In what type of depositional system was the shale deposited? Can we expect significant facies changes within the basin? Are there significant changes in thickness within the basin?

**Structuration**

The structural history of the basin after the deposition of the shales. In this part the following questions are addressed: Did any tectonic processes influence the lateral continuity of the shale? Are there areas with significant erosion or faulting? Here the preservation of generated oil and gas is also addressed by giving a brief description of the basin history including time of maximum burial/temperature of the shale and major erosion phases that can influence the preservation of generated hydrocarbons if available.

**Organic-rich shales**

A short description of the shale layer, e.g. sedimentary features. This description is given per individual shale layer separately. In the case that there is only one shale layer in the basin this description will be left out as it is already covered in the syndepositional chapter of the geological evolution.

**Depth and thickness**

The average depth and thickness of the layer and if known the depth and thickness trends throughout the basin for each shale layer.

**Shale gas/oil properties**

Maturity, total organic carbon content (TOC) and other organic petrographic parameter. How much organic matter is present in the shale and what do we know about the lateral extent and type of organic matter? Is there an established hydrocarbon system in the basin that is sourced by the shale? Are there any known hydrocarbon fields that are sourced by the shale? Where are these located within the basin? Are there any gas shows on logs of the shales? What is the maturity of the shale? How does the maturity change throughout the basin? Is the system biogenic or thermogenic?
### Risk component description

In the risk component description the previously described depositional and structural setting as well as shale properties are summarized and categorized for the general risk assessment. The subdivision in these categories gives a general overview of the risk associated with the shale gas/oil system. In the final report of WP 4 a summary table with the categories for all assessed shales is presented. This overview gives a general idea of the type of shale, its complexity and amount of data. This is used to categorize and compare the overall uncertainty/risk that is associated with the assessment. For example shales with little data and high structural complexity have a high risk of not containing any gas compared to shales with a large amount of data, good seismic interpretation and known HC content and mineral composition. The results of this classification are also taken into account in the final GIIP/OIIP calculation, where few data/high risk shales are assigned a higher range of values and therefore a higher uncertainty.

### Occurrence of shale

**Mapping status**
- **Poor**: no map, only outlines
- **Moderate**: depth map, thickness map based on interpolation/average values (few datapoints)
- **Good**: seismic interpretation, interpolated map (many datapoints)

**Sedimentary variability**
- **High**: very strong local differences, difficult to predict
- **Moderate**: depositional environment changes gradually throughout the basin
- **Low**: very homogeneous character throughout the basin

**Structural complexity**
- **High**: thrust setting, mountain belt, drastic compression
- **Moderate**: layer faulted, locally eroded, subsidence, uplift and salt tectonics
- **Low**: layer cake setting, predominantly steered by subsidence

**HC generation**

**Available data**
- **Poor**: no data
- **Moderate**: few data points (< 20)
- **Good**: good database (>20)

**Proven source rock**
- **Unknown**: no information
- **Possible**: HC shows and accumulation in other setting probably from same SR
- **Proven**: HC fields in study area proven to be sourced from shale gas layer

**Maturity variability**
- **High**: high local maturity variations (related to excessive faulting or magmatism)
- **Moderate**: basin wide trends related to present or past burial depth variations
- **Low**: very similar maturity throughout the basin

**Recoverability**

**Depth**
- **Shallow**: <1000m
Good 1000-5000m  
Deep >5000m  

Fraccability  
Unknown  
Good brittle mineral composition (>80% carbonates and/or quartz), fracturing tests, log interpretation  
Poor very clay rich (>50% clay content)  

References  
All relevant literature references for the basin  

4.2 Subdivision into assessment units  
Within a basin a shale formation can have significant lateral heterogeneities with respect to its properties (e.g., porosity, mineral composition and maturity) related to depositional processes or burial depth. Especially differences in maturity can have a big influence on the prospectivity of the formation. If possible these heterogeneities should be addressed by subdivideing the shale formation into different assessment units. This subdivision will be based on the geological description of the shales (step 1, see 4.1), the basin and the delivered GIS maps. Important parameters for this subdivision are:

- **Depth**  
  - For this assessment a maximum average depth of 5000 m and a minimum depth of 1000 m was assigned. Regions shallower than 1000 m were included in the assessment as possible biogenic plays or as very shallow thermogenic if the maturity suggests that they were located at higher depths in the past. Areas with an average depth of more than 5000 m were not considered any further.  

- **Thickness**  
  - An average thickness of 20 m has been set as the lower boundary for the assessment in this study. Shale layers thinner than 20 m on average are not taken into account in the final calculation of the GIIP/OIIP. Also information on the thickness distribution is necessary for the calculation of the total shale volume, formations without thickness information could not be included in the assessment.  

- **Maturity (Immature/oil/gas transition)**  
  - Immature shale layers were only included for the calculation of biogenic gas when the layer is shallower than 1000 m. The other formations were subdivided into oil shales for the calculation of the OIIP and gas shales for the calculation of the GIIP. This subdivision is based on the average measured vitrinite (or equivalent) reflectance.  

- **Biogenic versus Thermogenic gas systems**  
  - Shallow immature layers were included in the study as possible biogenic shale gas formations.  

- **Onshore/Offshore**  
  - Offshore areas were excluded from the calculation of the GIIP/OIIP  

- **Mineralogic including Porosity and Permeability**  
  - Subdivision not possible with current dataset  

- **Source rock quality (OM type and TOC content)**  
  - Subdivision not possible with current dataset
The subdivision into individual assessment units will be shown in the GIS environment. If needed, different analogues will be selected for each individual unit. This step reduces the overall uncertainty of the assessment as it reduces the variability of these parameters within one assessment unit. It also allows for the method to exclude parts of a shale layer that do not fulfill the assessment criteria and decide between the calculation of the GIIP and the OIIP.

### 4.3 Ranking of shales per country

The third step is a ranking/prescreening of the shales per country and per basin. This ranking/prescreening is based on a limited number of parameter and should be done for each shale assessment unit separately. In this step the general availability of data for the shale formation is included. This ranking/prescreening is supposed to identify the most interesting shale formations per country/basin with enough data available for a full assessment and limit the total number of formations a full assessment is performed on.

**Shale Gas/Oil System ranking**

- **TOC/OM**
  - Average < 1.5% → Measured TOC, known HC system, no TOC data available → Class 1
  - > 1.5% → No TOC data available, no known HC system, no TOC data available → Class 2

- **Depth**
  - Average > 5000 m → < 1000 m, 1000-5000 m, No depth measurement → Class 2

- **Thickness**
  - Average < 20 m or no data → 20-100 m, > 100 m → Class 1

- **Maturity**
  - Class 2 → Biogenic
  - < 0.6 % → Oil, Wet gas → Class 1
  - > 0.6 % → Gas, No maturity indication → Class 1

**Figure 4.1** Shale ranking/prescreening criteria used in step 2 (see 4.2)

The ranking/prescreening uses the most important and basic criteria and information necessary for a GIIP/OIIP calculation. The classes were defined to identify how close to a “normal” successful US type shale gas/oil system the formation is while the No class refers to formations that fall out of the assessment criteria or have insufficient data and are therefore not taken into account in the GIIP/OIIP calculation (Figure 4.1).

- Class 1 – Main screening parameters consistent with typical shale gas/oil play as known from plays in the US
  - GIIP/OIIP calculation
Class 2 – Some parameters are not consistent with typical shale gas/oil plays
  o GIIP/OIIP calculation with wider range for parameters and overall higher uncertainty
Class 3 – Some parameters are unknown
  o GIIP/OIIP calculation only if critical parameters are available. Possible zero value in uncertainty estimation
No – A parameter falls out of the range of shale gas/oil plays
  o no GIIP/OIIP calculation

These classes are used to illustrate the general level of risk associated with an assessment unit. Class 1 generally describes units with parameters that fall in the same range as the successful plays in the US. The overall risk is therefore considered low. Class 2 units have one or more parameters that are outside this range. These are units that are either very shallow, immature or very thick. A GIIP/OIIP assessment is still feasible; however the general risk that there is no gas/oil in these units is higher. A Class 3 unit is generally lacking critical information on depth, TOC or maturity. A GIIP/OIIP assessment would rely on analogue data for these parameters. The risk associated with these units is very high. However additional studies gathering data on these missing parameters could reduce that risk.

The prescreening criteria described in literature (e.g., Bammidi et al. 2011 or Pitcher et al. 2012) were designed for US shale gas/oil formations and are generally used to identify regional differences/sweet spots within one formation. The level of detail applied there is unsuitable for this study due to the lack of data for a large number of European formations. Furthermore this ranking/prescreening is only one part of the assessment and several other parameters taken into account in literature are included in the other steps (e.g. storage volume in the final GIIP/OIIP calculation, mineralogical composition in the general uncertainties).

4.4 GIIP/OIIP estimation

The detailed estimation of the GIIP/OIIP will be performed applying the stochastic volumetric approach using the following functions:

\[
\text{GIIP} = \text{GIIP}_{\text{free}} + \text{GIIP}_{\text{adsorbed}}
\]

where

\[
\text{GIIP}_{\text{free}} = V \times \phi \times \text{sat} \times B_g
\]

\[
\text{GIIP}_{\text{adsorbed}} = V \times \rho \times G
\]

\[
V: \text{Volume, m}^3
\]

\[
\phi: \text{Porosity, %}
\]

\[
\text{sat}: \text{Gas saturation, %}
\]

\[
B_g: \text{Gas formation volume factor, Rm3/Sm3}
\]

\[
\rho: \text{Rock density, g/cm3}
\]

\[
G: \text{Langmuir factor}
\]
For the stochastic calculation for each parameter the mean, minimum and maximum values are needed along with a probability density function that describes the distribution of the values in the assessment unit. These values are then combined by random sampling (Monte Carlo simulation) and give a probability distribution for the GIIP along with an indication which values have the biggest influence on the uncertainty of the calculated value.

In the following a short description of the necessary variables is given.

**Probability density function**

For each parameter a probability density function needs to be defined. The shape of the function is determined by the assumed distribution of values in the assessment unit and the mean, minimum and maximum value.

**Uniform distribution**

A uniform distribution is selected when the values are equally distributed and a high value is equally likely to occur as a medium or a low value.

**Normal distribution**

A normal distribution is the standard distribution in most cases. The distribution follows the standard bell shaped curve, the medium values are the most probable, the minimum and maximum values determine unlikely endmembers of the distribution.

Other types of distribution can be chosen when necessary.

**Volume**

Volume \( V = A \times h \times n/g \) \((m^3)\)

**Area** \((A)\) \((km^2)\)

a. Offshore

b. Onshore

Area of the shale layer in square kilometre, separated into onshore and offshore area. Only shales with an onshore component will be included in the study.

**Thickness** \((h)\) \((m)\)

Average thickness of the layer of the entire previously mentioned area.

**Net/Gross** \((n/g)\) \((\%)\)

How much of the previously defined thickness is actually prolific in percentage.

**Depth** \((m)\)

Average depth of the top of the Formation
Porosity ($\phi$) (%)

Matrix porosity based on measurements. Include type and number of measurements as well as uncertainty associated with the measurements in the comments.

Gas/Oil Saturation (%)

Gas saturation for Gas Shales / Oil saturation for Oil Shales. Give the percentage of pore space that is saturated by hydrocarbons. This value is generally determined during production. Please indicate if the given value is based on actual production data or based on an analogue.

Bg/Bo

Bg – Gas formation volume factor, Bo – Oil formation volume factor.

Gas or oil volume increase from reservoir to surface conditions. These factors are generally measured during production. The Bg can be calculated using the ideal gas law modified with the compressibility factor:

$$B_g = \frac{P_{sc} * z * T_{res}}{P_{res} * T_{sc}}$$

Bo is usually measured on the actual fluid during production tests.

Compressibility factor ($z$)

The ratio of the molar volume of a gas to the molar volume of an ideal gas at the same temperature and pressure. It is used to modify the ideal gas law to account for the real gas behavior.

Rock density ($\rho$) (g/cm³)

Rock density based on measurements. Include type and number of measurements as well as uncertainty associated with the measurements in the comments.

Langmuir parameter

Langmuir pressure (Psi)

Langmuir volume (scf/ton)

Langmuir pressure and volume are the result of adsorption measurements on real rock samples used to describe the possible amount of adsorbed gas on the sample. Reservoir pressure and temperature

Reservoir pressure and temperature (Pres and Tres) (Psi, °C)

Temperature and pressure range based on corrected well measurements. Include the number and depth range of the measurements. If not available give the general thermal and pressure gradient including indications of overpressure.
5. Assessment results

A general risk assessment and a ranking will be given for each of the identified shale gas/oil layers together with suggestions on how to reduce the general uncertainty of the formation. The top ranking shales with enough data available will be included in the detailed calculation of GIIP/OIIP based on the presented volumetric method. For these shale layers P50, P10, and P90 values along with the distribution of values and uncertainty related to each will be provided. Furthermore a summary of the main uncertainties that have the biggest influence on the total range of GIIP/OIIP values of each shale play will be provided, together with possibilities to reduce this uncertainty. Finally the results of this assessment are discussed against the results of earlier assessments of the same formation.

5.1 Example - 1001 - Baltic Basin - Zebrus Formation - Latvia

The Zebrus Formation, assessment unit 1001, is located in the south of Latvia. It was deposited in Early Ordovician times and in the Baltic Basin (Figure 5.1).

![Figure 5.1 Location of the onshore area of assessment unit 1001](image-url)
Table 5.1 Summary table of the general risk factors as extracted from the geological description of the formation (Assessment step 1, see 4.1).

<table>
<thead>
<tr>
<th>Mapping status</th>
<th>Moderate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sedimentary variability</td>
<td>Moderate</td>
</tr>
<tr>
<td>Structural complexity</td>
<td>Moderate</td>
</tr>
<tr>
<td>Data availability</td>
<td>Poor</td>
</tr>
<tr>
<td>HC system</td>
<td>Possible</td>
</tr>
<tr>
<td>Maturity variability</td>
<td>Moderate</td>
</tr>
<tr>
<td>Depth</td>
<td>Good</td>
</tr>
<tr>
<td>Fraccability</td>
<td>Unknown</td>
</tr>
</tbody>
</table>

The main area of uncertainty for the Zebrus formation is the presence of a hydrocarbon system. No data on the type or amount of organic matter is available and the maturity and mineralogical composition of the formation is unknown (Table 5.1, Table 5.2). Organic petrographic studies on well samples in combination with maturity modelling calibrated to measured vitrinite equivalent reflectance would drastically reduce the risk for this formation.

Table 5.2 Summary of the classification according to assessment step 3 (see 4.3) for the individual assessment units.

<table>
<thead>
<tr>
<th>Onshore</th>
<th>Offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>Maturity</td>
</tr>
<tr>
<td>1</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 5.3 Overview of the input data used for the assessment of the OIIP and the source of that data (NGS, TNO, EU analogue - EU, US analogue - US)

<table>
<thead>
<tr>
<th>Area (km²)</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Average</th>
<th>Distribution curve</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness (m)</td>
<td>26</td>
<td>48</td>
<td>37</td>
<td>Triangular</td>
<td>NGS</td>
</tr>
<tr>
<td>Depth (m)</td>
<td>1474</td>
<td>1670</td>
<td>1571.8</td>
<td>Triangular</td>
<td>NGS</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>1.2</td>
<td>14.1</td>
<td>5.7</td>
<td>Lognormal</td>
<td>EU</td>
</tr>
<tr>
<td>Saturation gas (%)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Saturation oil (%)</td>
<td>0</td>
<td>0.279</td>
<td>0.0356</td>
<td>Triangular</td>
<td>EU</td>
</tr>
<tr>
<td>Bg (gas)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Bo (oil)</td>
<td>0.76</td>
<td>1.1</td>
<td>1.04</td>
<td>Triangular</td>
<td>EU</td>
</tr>
<tr>
<td>Pressure (psi)</td>
<td>173.4102</td>
<td>194.1805</td>
<td>183.7954</td>
<td>Triangular</td>
<td>TNO</td>
</tr>
<tr>
<td>Langmuir Pressure (psi)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Langmuir Volume (scf/ton)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Density (g/cm³)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>23</td>
<td>58</td>
<td>40.5</td>
<td>Triangular</td>
<td>NGS</td>
</tr>
</tbody>
</table>
Figure 5.2 Top: Probability distribution of the OIIP for the Zebrus Formation, assessment unit 1001 as well as P90, P50 and P10. Bottom: Cumulative probability of the same assessment unit.

Table 5.4 Result of the OIIP assessment

<table>
<thead>
<tr>
<th>Statistic</th>
<th>Forecast values</th>
<th>Percentile</th>
<th>Forecast values (million barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trials</td>
<td>10000</td>
<td>P100</td>
<td>0.04</td>
</tr>
<tr>
<td>Base Case</td>
<td>1.5</td>
<td>P90</td>
<td>1.11</td>
</tr>
<tr>
<td>Mean</td>
<td>4.65</td>
<td>P80</td>
<td>1.71</td>
</tr>
<tr>
<td>Median</td>
<td>3.75</td>
<td>P70</td>
<td>2.33</td>
</tr>
<tr>
<td>Mode</td>
<td>-</td>
<td>P60</td>
<td>2.99</td>
</tr>
<tr>
<td>SD</td>
<td>3.62</td>
<td>P50</td>
<td>3.75</td>
</tr>
<tr>
<td>Variance</td>
<td>13.1</td>
<td>P40</td>
<td>4.57</td>
</tr>
<tr>
<td>Skewness</td>
<td>1.72</td>
<td>P30</td>
<td>5.64</td>
</tr>
<tr>
<td>Kurtosis</td>
<td>7.79</td>
<td>P20</td>
<td>7.06</td>
</tr>
<tr>
<td>Coeff. Of Variation</td>
<td>0.778</td>
<td>P10</td>
<td>9.39</td>
</tr>
<tr>
<td>Minimum</td>
<td>0.04</td>
<td>P0</td>
<td>33.9</td>
</tr>
<tr>
<td>Maximum</td>
<td>33.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean std. error</td>
<td>0.04</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The OIIP assessment for the onshore area of unit 1001 gives a median value of 3.75 million barrel of oil initially in place while the P10 value is 9.39 million barrel of OIIP. More detailed results can be extracted from Table 5.4. Figure 5.3 shows the sensitivity analysis of the OIIP calculation. The largest influence has the saturation being responsible for more than 75% of the total uncertainty of the OIIP value. The assumed range of porosity has the second most influence on the uncertainty of the OIIP assessment. Both parameters were used from local analogues and do not originate from measurements on the unit itself, which further increases the risk related to the final OIIP assessment.

In addition to the general uncertainty related to the lack of data with respect to organic matter content, type and maturity, it is suggested to acquire additional information on the range of porosity and oil saturation.

No previously published assessments were found for the Zebrus Formation. It is possible that the formation was included in the EIA (2013) assessment as part of the Baltic Basin however no separate OIIP value was given.
6. Example for notional field development plan

A field development plan is needed when assessing the total recoverable resources from an area based on the GIIP/OIIP. It examines the local surface and subsurface situation and tailors the wells and production facilities accordingly.

One example for such a notional field development plan was set up by Halliburton for EBN (Energie Beheer Nederland) for a study area in the south west of the Netherlands (Halliburton, 2011). This chapter summarizes the main points and prerequisites that were identified by Halliburton for this field development plan. For more detailed information it is suggested to consult the original study.

6.1 Technical analyses

Petrophysical evaluation

The petrophysical evaluation is based on already available well data or exploration wells. Its aim is to identify actual resource potential and fracturing potential at the study location. All available subsurface data has to be gathered for the identification of reservoir conditions and source rock type and quality (Mud logs, DTC and DTS together with PHIA and PHIN for stress calibration and rock property model, Log based brittleness and Young’s Modulus, dipmeter analysis).

Hydraulic fracture design

To identify the effects and prerequisites of the fracture design it is suggested to study different fracture modelling scenarios. In the presented study case scenarios for planar geometry modelling and discrete fracture network were studied for two different shale formations.

Production forecasting

The production forecasting is based on a layer cake model for which different scenarios for properties (e.g., permeability, length and number of fractures) are calculated while porosity and water saturation are taken from logs. Further assumptions for the model include continuous properties in each layer, no adsorption, PVT, gas specific gravity, gas viscosity, z factor, gas formation volume factor and fracture complexity. Fracture geometry and design are taken from the previous fracture simulation results, and run using four different scenarios with different lateral length and number of fractures to determine their impact on the production.

Well test conceptual design

Different types of well tests have to be used for different types of fluid composition and reservoir properties and the exact specifications have to be adjusted accordingly. The first well test therefore has as objective to better understand fluid type and reservoir properties and get a better idea of well deliverability, optimum drainage mechanisms and key parameters for future drilling and reservoir development. The following data and parameter have to be collected: Downhole pressure and temperature, surface flow rate for oil, gas and water for each fracture stage, reservoir fluid samples, surface pressure and temperature during flowing and shut-in, testing for H₂S and CO₂, heavy metal analysis and pressure data during initial flow, subsequent flow and buildup periods.

Well design

The well design is strongly dependent on the local geology and geography. Therefore a preliminary hazard map has to be created using general surface and shallow subsurface information to identify possible well pad locations. In this study maps of
buildings, drill free drinking water zones, drinking water production zones, ecologically sensitive areas, existing safety zones, groundwater protection zones, natura2000 areas, overhead power lines, railways, roads, surface water and underground gas pipelines were used for this hazard map.

### Completion design

Several different completion techniques are generally used in the industry (Table 6.1). The local geology and financial assumptions generally determine which technique has the best cost and return factor.

<table>
<thead>
<tr>
<th></th>
<th>Perf &amp; Plug</th>
<th>Sliding Sleeve</th>
<th>HJAF</th>
<th>HP-ACT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Intervals</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Perf Time/Stage (hrs)</td>
<td>4</td>
<td>0.1</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Total Perf/Move Time (hrs)</td>
<td>40</td>
<td>3</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td># Intervals/Stage</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Treatment Rate (bpm)</td>
<td>100-60</td>
<td>100-60</td>
<td>45-20</td>
<td>45-20</td>
</tr>
<tr>
<td>Total Fluid Volume (gals)</td>
<td>1500000</td>
<td>1500000</td>
<td>1500000</td>
<td>1500000</td>
</tr>
<tr>
<td>Total Proppant Volume (lbs)</td>
<td>1500000</td>
<td>1500000</td>
<td>1500000</td>
<td>1500000</td>
</tr>
<tr>
<td>Diversion Time/Stage (hrs)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.5</td>
</tr>
<tr>
<td>Total Diversion Time (hrs)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>14.5</td>
</tr>
<tr>
<td>Hydraulic Horsepower (HHP)</td>
<td>300000</td>
<td>300000</td>
<td>15000</td>
<td>14000</td>
</tr>
<tr>
<td>Total Frac Method Time (hrs)</td>
<td>50.37</td>
<td>13.37</td>
<td>46.12</td>
<td>60.62</td>
</tr>
<tr>
<td>Screenout Contingency Time (hrs)</td>
<td>20</td>
<td>24</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Final Wellbore Cleanout Time (hrs)</td>
<td>72</td>
<td>0</td>
<td>0</td>
<td>8</td>
</tr>
</tbody>
</table>

### 6.2 Environmental impact and regulatory framework

In the second part of the development plan the regulatory framework with respect to the development of shale gas resources in the study country is described as well as the potential influence of the development on the environment (water resources, air quality, ecological impact, general environmental impact, health and safety and quality of life). Several timelines are constructed to show the time needed for legal proceedings as well as drilling time, waste treatment and deconstruction. The financial framework is not included in this example.

### 6.3 Result

The result of the notional field development plan for an example study area in the south west of the Netherlands is a hypothetical "base case" scenario. Within this scenario the location for 83 possible well pad locations were identified with a total of 426 wells/laterals that can be drilled. For a complete production plan several unknown parameter need to be investigated. The main uncertainty with respect to the drilling technique and completion design is that the exact amount and type of fluid is currently unknown. It is therefore impossible to determine a recovery factor for the study area. An exploration well with production tests would be needed to resolve that issue.
7. References

Advanced resources international (ARI), (2011) world shale gas resources: an initial assessment of 14 regions outside the United States. Washington, DC: Advanced Resources International Inc


