Methodologies and Tools for Coalbed Methane (CBM) Field Development Planning Studies
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Abstract
Resource plays such as Coalbed Methane (also called Coal Seam Gas) fields typically exhibit a number of unique characteristics that set them apart from other hydrocarbon accumulations. We will argue in this paper that as consequence, conducting effective field development planning studies for CBM resources requires adopting a markedly different approach to the ones typically followed with conventional oil and gas fields.

In contrast to traditional offshore plays, replete with a rich literature of best practices and adequate tools, coalbed methane field development planning typically involves very large areas and number of wells, hence a correlative abundance of (static and dynamic) data, but also displays an often surprising variability between neighbouring wells. This variability is the consequence of a high degree of heterogeneity present at a small (1’s-10’s metres) to medium (10’s-100’s meters) scale, notably for permeability, but also isothermal properties, gas content, and even net coal distribution and seam geometry for some plays.

This paper offers insights on integrated development planning methods, uncertainty management techniques and modelling workflows, accumulated through the experience of a number of CBM plays. Expected relationships and possible cross-parameter models for the key reservoir properties are discussed. The development of practical tools to characterise the reservoir properties, as well as the performance of different well and completion configurations, simulation, field development planning, all the way to ultimately assessing the economic potential of the play are also illustrated.
**Introduction**

Production from coal beds differs from conventional gas production in a number of aspects. These differences are caused by the following underlying factors:

- high heterogeneity at small scale (resulting from the fractured nature of these reservoirs),
- large development area with a relatively tight spacing and therefore high numbers of wells,
- challenges resulting from the combination of storage mechanisms (adsorbed and free gas) and various flow mechanism (diffusion and Darcy flow).

The above stated elements have a great influence on the approach that should be used for CBM development planning. Differences in reservoir properties of even several orders of magnitude between neighbouring wells are often encountered (e.g. permeability) and the localized heterogeneity results in a large uncertainty regarding production rates during early phase of development and volatility of production profiles to extent greater than in case of conventional developments. In addition, the productivity of wells remains typically very low while gas production potential remains poorly predictable during early well production. This results in high economical risk and uncertainty in delivering gas.

These challenging project characteristics cause necessity of inventing innovative field development planning and reservoir management techniques that would account for the production and capitalization being utterly different from the characteristics of conventional gas fields [3]. To address these issues, development and production forecasting techniques different from these used in conventional reservoirs should be used.

In this paper we show a conceptual workflow that we created and that helps in better development planning of highly heterogeneous coal bed methane reservoirs. Key elements of the workflow are shown in Figure 1. Fundamentals of reservoir characterization, production forecasting and development planning according to our workflow are discussed in this paper. We believe (and we are trying to demonstrate in this paper) that the main ingredients for successful CBM field development planning are:

- necessity for adequate characterization of variability vs. uncertainty [4],
- rigorous and repeatable workflow that utilizes all relevant data,
- introduction of metrics that allow for identification of the influence of subsurface parameters and development decisions on the value of a project.

The workflow can be repeated for various CBM reservoirs in order to allow a comparison between the relative values of various development projects.
Reservoir Characterization, Static Modelling and Volume in Place assessment

In order to build an adequately representative static model of a CBM reservoir it is necessary to go through the process of reservoir characterisation. Whilst the process itself is nothing new and is well established for conventional reservoirs, CBM plays are typically characterised by greater heterogeneity and suffer from very significant variability. There are a number of parameters that influence production characteristics of CBM wells. The relative importance of some of them is different than in case of conventional reservoirs. A number of CBM specific phenomena are also present, such as e.g. matrix shrinkage and gas storage by means of adsorption. The importance of individual parameters on various characteristics of production also varies. Any parameters that may have effect on production from wells should be identified and listed. After the ranges of uncertainty for individual parameters are identified, their influence on production characteristics (such as time to first gas, time to dominant gas, time to peak gas, peak gas rate, cumulative gas recovery and recovery factor) should be tested (e.g. with use of simulation techniques) and correlations between various parameters should be investigated.

Variability and uncertainty

With highly heterogeneous systems, where large differences are found from one observation (e.g.: a given well) to another observation (a neighbouring well), it is important to understand the difference between variability and uncertainty [4].

Variability is defined as a short to medium scale (up to inter-well scale) variations of a given parameter, such as permeability, porosity, gas content (for CBM reservoirs), hydrocarbon saturation etc. Variability is intrinsic and non-temporal. Ultimate understanding of variability often remains spacially poorly predictive [4].

Uncertainty is defined at the field, sector or segment (field unit) scale, where multiple wells will be ultimately drilled. It represents, at a given time, how well a field unit is understood. Generally, uncertainty reduces with time and information becoming available. Development related metrics (e.g. field recoverable volumes), at a given time, are a consequence of the level of understanding of the subsurface and the concept development choices that were made [4].

Uncertainty and variability analysis should be carried out as part of reservoir characterization. This allows for a subsequent
meaningful geostatistical modelling. Utilizing models of property trends in function of other properties should be used for generating property maps (e.g. co-kriging). Any erroneous data should first be removed, and the remaining points honoured in constructing maps. Once understanding on localized variability is gained it can be introduced into the picture by utilizing geostatistical techniques allowing for depicting variability (e.g. Sequential Gaussian Simulation).

**Alternative approaches to reservoir characterisation**

Two alternative approaches are possible to identify the variation in the reservoir properties. The first approach (a) is based on creating maps of properties based on available spatial data and mapping techniques. Alternatively (b) global distributions of these properties can be prepared based on multi-variate regressions to map based properties. The former approach (a) should be used in most cases. However a quick first-glimpse evaluation can be made based on (b) in order to identify any global trends and the theoretical range of values for the entire reservoir.

Whenever correlations between two or more properties are recognized the authors recommend a proper analysis based on available spatial data and mapping techniques. However if a property shows no correlation to any other property within an investigated CBM asset and does not show any spatial trends (i.e. the statistical distribution of data is uniform in all areas of the reservoir), global distribution models are sufficient to describe a particular asset. One should be wary of the fact, that certain properties may display trends in some reservoirs, while being uniformly spatially distributed in other reservoirs. One such an example is net coal thickness.

The examples of properties that should be typically analysed based on spatial data and mapping techniques are: permeability, porosity, depth, gas content, isotherm properties, etc. An example of property which the authors recognized as suitable in most cases for a global model is skin effect.

**Selection of key parameters for reservoir characterization**

The distributions of the investigated parameters can be identified based on global property distributions (see (b) in Alternative approaches to reservoir characterisation section) as part of reservoir characterisation and values for low, reference and high case can be selected based on P90, P50 and P10 values identified from their distributions. An example of gas content distribution with selection of low, reference and high case based on P10, P50 and P90 values in field global distribution is showed in Figure 2.

![Figure 2: Example of gas content distribution](image)

Subsequently, sensitivity runs can be made for all characterized properties and comparison of the relative importance of each of them can be made. The outcomes of such a comparison can be visualized as a set of tornado plots. These identify the importance of individual parameters on various characteristics of CBM well production profiles. Based on the observations, the number of parameters to be carried as uncertainties can be narrowed and further work should be carried based on most important parameters. An example of tornado plots that allow concluding regarding most significant uncertainties for a particular reservoir is shown in Figure 3.
Figure 3: An example of possible sensitivity of individual production characteristics to field uncertainties in a CBM reservoir.
From authors’ experience it is clear that the most crucial parameters will tend to vary slightly between assets. However typically the most crucial reservoir parameters from the perspective of commercial value of a CBM project include the following:

- Permeability
- Relative permeability
- Net pay
- Matrix shrinkage and compaction
- Adsorption isotherm and gas content
- Seam continuity
- Porosity
- Skin factor (unlike the remaining parameters, this is not a subsurface uncertainty)

Proper identification of the importance of uncertain parameters and their influence on field development is crucial for optimizing the development strategy. The range of uncertainty in reservoir parameters and correlations between uncertainties should be identified as part of reservoir characterization. For each of the parameters the influence of change in its value on various production characteristics should be evaluated. The decisions regarding categorization of uncertainties can be made based on tornado plots similar to these showed in Figure 3.

Each of these would have a different significance from the perspective of economical value of CBM projects. Due to the discounting effect, dewatering and well productivity will have the highest influence on NPV of projects. Volumes in place and connectivity will typically show more limited importance as they will influence mostly late well production.

**Importance of seismic data in reservoir characterization**

It is often encountered that in CBM reservoirs seismic lines are available, but not properly utilized. Focus should always be put on identifying available seismic data and on its processing. This allows for improving the quality of net pay mapping, as well as for high-grading areas in terms of finding high GIIP/km² locations.

A study of available seismic data can result in identification of sub-optimally positioned wells and in ideas regarding locations for future development wells. An example of identified wrongly positioned wells is shown in Figure 4. In the case showed in Figure 4 study of synthetic-to-well ties was carried in key wells across investigated area to understand the seismic response and robustness of amplitude interpretations, then 2D mis-tie analysis was also made to improve the quality of the top-reservoir horizon interpretations. ‘Stratal slicing’ using gated amplitude extractions through the coal-bearing package, guided by the top-reservoir horizon was then conducted. ‘A over B’ technique was utilized to correct for variations in background amplitude due to different vintage and processing parameters of the various 2D surveys used in the study. Subsequently variogram analysis and amplitude map kriging was prepared. Finally correlation between amplitude and net-coal was made by means of co-kriging well-based net coal with amplitude data to obtain improved net pay map shown in Figure 4.

![Failed appraisal wells](image)

**Figure 4:** Locations of failed appraisal wells in an investigated CBM field showed on net pay map guided by seismic data

**Permeability modelling**

Permeability analysis is a necessary step of reservoir characterization and proves to be much more challenging than in case of conventional reservoirs. Core samples cannot be successfully used in permeability evaluation (as they usually result in overestimating permeability) and typically DST outcomes are interpreted to identify permeability. The interpretation can often
be challenging (with extreme skin effect values recorded sometimes, attributable to number of causes [7]) and the resulting permeability distribution over a play may vary greatly. Authors generally agree that a trend of decreasing permeability with increase in depth is encountered in CBM reservoirs [4, 6]. However with the great localized variability the depth trend may not be visible if sufficiently large database is not available (Figure 6 show a sizeable permeability dataset which allows for identification of permeability-depth trend which may not be visible with a more limited number of data points). Contrasts in vertical permeability within a given well, as well as areally between adjacent neighbouring wells can be up to two to three (2-3) orders of magnitude.

Stress present in coals can have major influence on permeability. In order to understand the importance it is necessary to realize that:

- Permeability depends on the number (density), aperture, length and filling of discontinuities in coal
- Aperture of discontinuities in coal is typically higher when main stress direction is parallel to the discontinuities (Figure 5)
- Aperture of discontinuities in coal is typically lower when main stress direction is perpendicular to the discontinuities (Figure 5)

![Figure 5: Aperture change of coal discontinuities resulting from change in main stress direction; main stress direction shown with red arrows; no main stress direction (left), main stress direction parallel to discontinuity (center) and perpendicular to discontinuity (right)](image)

Permeability is usually the parameter carrying highest variability. In a typical CBM reservoir permeability can differ by a few orders of magnitude and such variability can occur laterally within the inter-well space, as well as vertically over the different coal measures. Coalbed permeability in the author’s experience appears to vary at a scale comparable to the borehole (1’s to 10’s of meters), which makes sweet-spotting a very difficult task. It is not the purpose of this paper to elaborate in great details about permeability dependencies and controlling factors, but rather to propose a practical way to characterize it within the realm of reservoir characterization.

One of the key accepted controls for permeability is the stress regime that coals are under. Of prime importance, overburden stress, and therefore depth, is recognized in several literature sources, that permeability decreases with depth [3, 4, 5, 9]. When abundant measurements are available, it usually happens that a high amount of variability (due to many factors often difficult to elucidate as we discussed earlier), and hence this global trend can be easily hidden.

We propose a statistical approach to identification of depth ranges in function of depth. Permeability should be approached on ‘depth bin’ basis. Depth ranges should be specified and permeability ranges (and distributions) should be captured in depth bins. This approach allows for identification of how P10, P50, P90 and mean permeability values change with depth. An example is shown in Figure 6. Depth bins of 500-750m, 750-1000m, 1000-1250m and 1250-1500m have been created and distributions have been prepared for each of the depth ranges. Based on the P10, P50 and P90 values it is possible to recreate the permeability distributions in individual bins and therefore obtain a more meaningful permeability model.
To a certain degree alterations in net pay can influence the significance of permeability. Net pay varies to much lower degree, compared to permeability, however influences both volume density and the productivity of wells. It therefore can have significant impact on well production at all stages. When net pay is too low, even very high permeability will not make production economically viable due to too low resource density.

**Matrix shrinkage and compaction**

In many cases matrix shrinkage and its influence on permeability can become the most critical parameter. The changes in coal permeability and porosity in function of pressure is guided mostly by Young modulus and to a certain degree by Poisson ratio. These are in turn related to the reservoir depth and coal properties. The greater the depth (and the lower the porosity) the higher the importance of matrix shrinkage and compaction is.

**Seam continuity**

Seam continuity and resulting connectivity in coal can have a significant impact on cumulative gas production. In most cases though it occurs that from economical perspective the significance of coal connectivity is very limited. And that is for multiple reasons, such as:

- Typically distance between wells is lower than seam continuity and therefore seam continuity loses its significance, as sweep area of individual wells is limited by the sweep area of its neighbours,
- Seam continuity affects negatively only late part of well production (tail production) and lowers cumulative well production, which has a limited significance from economical perspective due to the discounting effect,
- Due to limited drainage area the volume of water connected to a well is also low, which results in shortening of dewatering time and advancing gas production, from economical perspective this leads to increase in economical value of production.

For the above mentioned reasons it is even possible, that in extreme cases limited connectivity may result in improvement in economical value of well production, provided that well spacing is sufficiently dense and dewatering is shortened to a significant degree.
Porosity modelling – and porosity-permeability relationship

Porosity analysis can be prepared based on cleat data – the numbers of discontinuities in coal, and their apertures. Ranges and statistical distributions of porosity in function of permeability can be identified from this data. An approach to identify single- and subsequently multi-variate correlations between porosity and other reservoir parameters is briefly showed in subsequent paragraphs.

Since fracture spacing and aperture control both fracture porosity and permeability, a relationship between porosity and permeability would likely exist. Theoretical relationships for parallel-plate fracture networks are often used to estimate a porosity-permeability function.

Models that describe the relationship between fracture spacing, fracture aperture and fracture permeability for simple parallel-plate fracture systems following Poiseuille’s law [8, 9] can be used to estimate a range in fracture permeability first. The Planar Poiseuille equation can be used [8]:

\[ K_{\text{fract}} = 84.4 \times 10^5 \times W^3 / Z \]

Where:
- \( K \) – permeability [Darcy]
- \( W \) – aperture of fractures [cm]
- \( Z \) – spacing of fractures [cm]

By anchoring the estimates of permeability for ranges of fracture aperture and spacing (for a given investigated field) porosity-permeability functions can be created. The function describing porosity/permeability relationship is as follows [8]:

\[ \Phi = K^{1.2} \]

Where:
- \( \Phi \) – porosity [-]
- \( K \) = permeability [mD]

From the above equations a set of porosity-permeability models can be derived. A set of models is shown in Figure 7, the models include:
- constant aperture model
- constant spacing model
- variable spacing and aperture model
- constant porosity model

![Figure 7: Porosity-permeability models based on parallel-plate theory following Poiseuille's law](image)

Porosity greatly affects dewatering time when production from CBM reservoir is carried. Dewatering behaviour reduces the uncertainty in the range of porosity. However, it is possible and often encountered that porosity is wrongly estimated if the contribution of interburden is not accounted for in the course of calculation of water recovery.
Seam continuity and correlativity
The continuity of individual seams can be an important parameter to consider in the field development planning phase. The continuity of seams is influenced by both the structural complexity (minor and major faulting), and the stratigraphic complexity – some systems have a greater tendency for ponding and channel intersections [5, 6]. Variogram analysis on well data, combined with seismic interpretation and borehole image interpretation can provide valuable insights on the causes, expected degree and scale of the seam discontinuity risk. On top of these, analysis of changes in number of seams between wells and the dip that would be necessary between neighbouring wells in order to match the depths of individual seams can be made. The mapped outcomes often allow for identification of areas suffering from continuity-related issues. The risk with areally disconnected systems is that undrained volumes can be left behind (lower RF or UR/well). Conversely, such systems offer the advantage of rapid dewatering and early gas production, particularly evident in the early pilot stages. So discontinuity at a certain scale may offer an economic benefit. Finally, seam continuity needs to be considered in relation to an optimum spacing. Question should be asked what spacing would be required in order to fully connect the system. If the resource can be developed economically at a very tight spacing (with high resource in place density plays) then the risk of seam discontinuity becomes low.

Skin effect
A very wide range of skin (between ~10 and 100’s) is typically obtained for CBM wells based on conventional well test analysis, and that’s for multiple reasons including, but not limited to the presence of coal fines, densely fractured nature of coals and very low permeability values [12]. The big range of indicated skin is one of the factors that make the identification of permeability values very challenging. Various well drilling and completion techniques can affect skin factor. Usually a small stimulation process is enough to significantly lower skin effect [11].

Gas content and isotherm modelling
Identification of gas content and isotherm properties is crucial for estimation of GIIP, gas saturation, dewatering index and desorption profile. Gas content evidently plays a crucial role in the calculation of resource in place (GIIP and GIP/km2 or resource density). A number of individual data types can be compared to identify existing correlations on single- and multivariate level. The comparison and subsequent analysis of available data should result in preparation of description of the relationship between gas content, Langmuir Volume and Langmuir Pressure based on parameters such as e.g. coal rank, reservoir temperature, ash and moisture content and pressure. One of the crucial parameters from the perspective of CBM reservoir characterisation is dewatering index. When discussing the relationship between gas content and isotherm line it is important not only to know what the saturation of a given coal is (i.e. the gas content at a particular pressure divided by the maximum gas saturation permitted by isotherm line at that particular pressure), but also dewatering index (i.e. the pressure change from a given reservoir pressure required, for a coal described by a particular gas content and an isotherm line, to start desorbing gas). The dewatering index often proves to be more important than saturation by allowing for identification of reservoir pressure at which gas desorption will start and approximation of dewatering time.

Gas content is critical from the perspective of GIIP density and it is typically the single most important parameter influencing it. However as long as gas content is treated independently from parameters defining isotherm (typically Langmuir Volume and Langmuir Pressure are used as the parameters describing isotherm) it can be misleading. Only combination of gas content with isotherm properties at a given reservoir pressure provides information critical from the perspective of influence of these parameters on CBM well production behaviour. Two critical values can be derived from combination of gas content and adsorption parameters, namely saturation and dewatering index. Surprisingly the significance of saturation is typically lower, than that of dewatering index. Dewatering index can be defined as the pressure drop required to start gas desorption. While saturation provides us only with information regarding the volume of gas adsorbed versus the maximum volume that can theoretically be adsorbed at a particular pressure. Dewatering index takes this information and indicates by how much the reservoir pressure has to drop in order to start desorption process. The situation is shown in Figure 8.
The authors identified that a better correlation exists between Dewatering Index and various production parameters (e.g. cumulative recovery, time to peak gas, peak gas) than between saturation and various production parameters. A set of runs with various VL, PL and gas content was prepared to check these correlations. The outcomes are showed in Figure 9.
Figure 9: Correlation between well production parameters and Dewatering Index (left) and Saturation (right)
Statistical relationships between parameters

It is customary and good practice to look for relationships between parameters (such as permeability and depth for instance, or isothermal properties and maceral content etc.). However these observations and relationships are usually difficult to make (given the often different scales of the respective assessment) and suffer from large scatter. Two main useful inferences can often be made, if the dataset allows doing so:

1) **Statistical relationships** may be present, such as e.g. ash content and net seam thickness, or permeability vs. Depth, these may be identified based on global distributions (see section Alternative approaches to reservoir characterisation)

2) **Large scale trends** are often present, but masked by small scale variability: an example of net pay map for one of the reservoirs investigated by the authors is shown in Figure 10.

![Figure 10: Net pay distribution generated using SGS displaying high localized variability with a consistent large scale trend across the area showed (higher net pay values in the N-E corner of the area)](image)

Volumetric Assessment

A set of reference case maps should be prepared in order to obtain a base case deterministic GIIP and GIIP density maps. The minimum set of maps necessary for this purpose is:

- net pay map,
- density map
- gas content map,
- ash and moisture content maps may be necessary depending on whether density and gas content were reported on ‘as received’ or ‘dry ash free’ basis.

Additionally high and low case deterministic GIIP and GIIP/km² maps can be prepared based on replacing reference maps with high or low case alternatives. These, combined with recovery factor maps allow identification of areas meeting screening criteria for minimum GIIP connected to individual wells to allow for economical development.

Probabilistic GIIP evaluation should also be carried out in order to indicate the possible range of outcomes. Probabilistic runs workflow (offered by multiple commercial packages available on the market) can be used to obtain stochastic GIIP and GIIP standard deviation maps.

Two other methods of GIIP calculation can also be applied:

- In the first method statistical analysis software should be used in order to prepare Monte Carlo simulation [1] with distributions of individual parameters resulting in distribution of GIIP. This approach can be referred to as ‘global distribution approach’ and results in wide range of outcomes.

- The second method starts with creating a number of deterministic realization maps based on the previously identified low, reference and high cases for individual properties (e.g. net pay, bulk density, gas content, etc.). For each realization its probability and GIIP value is obtained. Thus GIIP distribution is prepared. This approach is based on ‘spatial distributions’ and results in narrower range of uncertainty in GIIP distribution.

The comparison of distribution from Monte Carlo probabilistic evaluation and from generation of multiple realizations should be made in order to gain certainty regarding the P10/P90 range of outcomes. Visualization of deterministic and probabilistic GIIP calculation methods based on maps of net pay, ash content, moisture content, bulk density and gas content maps is given in Figure 11.
Figure 11: Deterministic and probabilistic GIIP calculation methods

CBM dynamic modelling and production forecasting.
Contrary to conventional offshore field developments, where full-scale numerical dynamic modelling has become the norm, the approach proned by the authors and followed widely in the CSG/CBM industry is one that relies on a three stage approach based on single well modelling followed by mini sector modelling and analytical approach to full field modelling [10]. This is a natural outcome that arises from the fundamental differences between the CBM-type resource plays and conventional (offshore) fields. Table 1 captures the main elements of the comparison between these environments and the resulting best practices for dynamic modelling.
### Table 1: Differences between development of CBM plays and conventional offshore fields

<table>
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<tr>
<th></th>
<th>Onshore CBM Plays</th>
<th>Offshore fields</th>
</tr>
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<tbody>
<tr>
<td><strong>Areal Size</strong></td>
<td>100's-1000's km²</td>
<td>10's-100's km² (when giant fields, sectorisation conducted)</td>
</tr>
<tr>
<td><strong>Resource Density (in place)</strong></td>
<td>Generally 2-6 Bscf/km², World class around 8-10 Bscf/km²</td>
<td>Generally 20-40 Bscf/km² Often marginal when in the low 10's Bscf/GIIP. World class with 50+Bscf/km²</td>
</tr>
<tr>
<td><strong>Number of wells / km²</strong></td>
<td>Typically 1-5 wells/km² (spacing between 0.4km and 1km)</td>
<td>Varies greatly, typically lower than in CBM, due to high well cost a high connected volume is necessary</td>
</tr>
<tr>
<td><strong>Characteristics of key uncertainties</strong></td>
<td>Difficult to measure with well logs, core and DSTs at the well location and difficult to extrapolate beyond well location</td>
<td>Often geologically driven and targeted by appraisal. Inter-well property distribution can be improved through technology (Geophysics Q.I)</td>
</tr>
<tr>
<td><strong>Variability encountered over field</strong></td>
<td>Very large &gt; up to 1-2 orders of magnitude (Peak rates, Ultimate Recovery) in well profiles over the field</td>
<td>Variability in well profiles (in terms of cumulative recovery or peak rates) hardly ever exceeds an order of magnitude</td>
</tr>
<tr>
<td><strong>Uncertainty range and how it reduces through Appraisal</strong></td>
<td>Large early on, but often large residual uncertainty even after pilot production</td>
<td>Medium to Large, but generally rapidly decreasing with appraisal and development</td>
</tr>
<tr>
<td><strong>Resulting Areal predictability</strong></td>
<td>Poor: Probabilistic static modelling to honour variability</td>
<td>Good to Medium: Deterministic modelling generally preferred to test explicit development concepts (combined with GeoStats)</td>
</tr>
<tr>
<td><strong>Resulting well concept strategy best practices</strong></td>
<td>Consistent approach applied to 'sectors' or 'development units' sharing some geological traits Early Investment in Technology trials</td>
<td>Front-End loading for concept select as limited 'failure' opportunities Well by well approach Increasing reliance on complex well geometries to access mapped sweet-spots</td>
</tr>
<tr>
<td><strong>Resulting best practices dynamic modelling</strong></td>
<td>Understanding variability vs. uncertainty: Heterogeneity captured at well level: uniform 'average' properties seen within well drainage Importance of analogue to infill disparate knowledge. Speed preferred over complexity Statistical treatment of variability (individual well expected range of performance) vs. field uncertainty (sector type curve uncertainty) is fundamental</td>
<td>Incorporate geological uncertainties and mitigate them with well concept select Complex modelling allowing well trajectories testing in dynamic model</td>
</tr>
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</table>

Scale modelling is an approach to effectively understand the impact of uncertainty at different scales. We propose a three-scale approach to capture most learnings on various level of detail. These are, from increasing scale: single well, sector and full field, and their objectives are:

- Single well modelling is generally preferred to capture the uncertainty and variability ranges. High numbers of runs investigating the sensitivity of production profiles to various reservoir and technology uncertainties should be run. Single well models allow also for introduction of great number of details that would not be time-effective (or even possible) to introduce in modelling of large areas with high numbers of wells. Single well models serve also as generic box models giving steer for data acquisition and well typing. A suite of single well runs allows for ranking of dynamic uncertainties. The simulations can be prepared as numerical or analytical simulations depending on requirements (analytical simulation allows for fast screening and identification of sensitivities while numerical simulation allows for evaluation of implications of localized heterogeneity and in some cases allows for better representation of early flow behaviour).

- Mini sector models can be prepared to investigate the continuity of coal zones, drainage area of wells, connectivity between wells and possible interactions. The understanding of reservoir behaviours resulting from single well models should be utilized in the course of setting up of the simulations. Mini sector models should be carried with use of numerical simulators (due to limitations of analytical models). Provided that a limited number of wells are introduced, this simulation level allows for introducing detailed geological models (even on seam level) without sacrificing time efficiency. Such mini sector models should be used for history-matching of production of simulated wells (authors suggest finding ranges of matching parameters and comparing these to the ranges identified for a given reservoir as opposed to finding a single match) and subsequently can be utilized in a number of ways including:
  - identification of productivity of wells drilled and completed with use of alternative techniques,
  - understanding the interactions between wells,
  - investigation of alternative relative locations of wells in the reservoir,
  - identification of infill opportunities.
Finally full field model can be prepared to investigate optimum development phasing, sequence and pace, as well as sizing of surface facilities and other large scale factors. Authors realized that simulation of the high number of wells which is typically planned in a development of a large CBM field (up to 1000’s of wells) could not be time-efficiently carried with use of full 3D modelling and semi-analytical model is suggested instead. The part of the reservoir drained by each well is simulated as a tank (or a set of tanks representing individual zones or seams) disconnected from the remaining tanks.

Property maps created in the course of reservoir characterization should be used to create the inputs for full field model. For the purpose of analytical simulation proposed by authors these maps should be upscaled accordingly to well spacings selected for individual realizations. Thanks to the time efficiency of analytical modelling a number of alternative subsurface realizations, spacing assumptions and development scenarios can be created in a reasonable timeframe.

The ultimate goal of the workflow used for full field modelling should be the identification of the possible range of the CBM development project value. This is obtained by indicating the range of production potential for individual wells, followed by generation of field production forecast, appropriate sizing and costing of wells and surface facilities and running a first pass economical analysis of the project based on various full field model scenarios.

In many cases decision has to be made regarding the sequence of development, where multiple competing sectors or projects are to be investigated. In such cases the workflow presented above should be repeated for individual sectors or projects. This will result in obtaining comparison of relative value of alternative solutions. The outcomes should serve as the first-pass screening tool and the best candidates can then be compared on more in-depth basis.

Field Development Planning

With the basic ingredients of the static and dynamic modelling process in place, we can now cover the main constitutive elements of the field development planning workflow for CSG fields. These are:

- **Well Technology concept selection**: Selection of the preferred or optimum well technology should be made: this includes well trajectory (vertical, deviated, horizontal and more complex well types such as multi-laterals, surface-to-in-seam and pinnate wells) and completion options.
- **Spacing**: Well spacing proves to be one of the most important aspects of CBM development projects.
- **Sectorisation**: The overall field or total prospective development area may need to be split into sectors depending on the size of the project and the development plans.
- **Drilling pace and sequence**: The number of wells drilled per year and the locations of subsequent wells have to be carefully planned.

Technology Selection

CBM play are generally developed in a continuous manner, over a number of years, and offer the opportunity of a manufacturing-like approach to drilling, completing and tie-in new wells. As a result, economies of scale (EOS) over a large number of repetitive, standardized concepts become more attractive than the benefits of well-by-well designer approach to developmental activities.

That said, opportunities for continuous improvement and optimization do exist, and can be applied as successive ‘generations’ of wells and associated developmental activities. To that effect, capturing learnings from earlier wells is essential, and investing in technology trials is often proven valuable.

A number of factors have to be taken into account when considering selection of technology. A trade-off has always to be made between use of sophisticated technology that allows for maximizing recoveries and rates and minimizing the costs of development. From well drilling perspective the CBM field development requires a fundamental optimization and compromise between:

- a) surface aspects: limiting surface acquisition, gathering facilities scope and costs,
- b) well drilling and completion aspects such as well trajectory aggressiveness, rig selection (slant vs. vertical) and well operational considerations, whilst achieving the desired subsurface drainage plan, at the selected well spacing.

Certain reservoir properties cause the necessity of using particular drilling and completion techniques. Based on usability of individual technologies well technology maps are created.

Out of all usable technologies decision has to be made regarding the optimum technology for particular areas of a given reservoir. The decision is based on simulation work coupled with economical evaluation of CBM projects in case when a particular drilling and completion concept is used for given groups of wells.
Well spacing
Well spacing proves to be one of the most important aspects of CBM development projects. While too sparse spacing will result in destroying the economical value of the project due to low sweep efficiency and long dewatering time, too dense spacing will ruin the economical value because of low cumulative recovery per well. While possibility of infilling later in field live exists, in many cases optimum spacing lands between the originally selected spacing and the infill spacing (halving the original distance between wells).
Selection of optimum well spacing has to be the trade-off between acceleration of gas production, gaining high production rate and obtaining high cumulative recovery; the first can be obtained by dense grid of wells, the last by allowing a well to sweep from large area. While dense well spacing will result in lowering cumulative production, from economic standpoint it can be justified (to a certain degree) by increasing early gas production.
Pad drilling can also be utilized, which results in introducing multiple wells from a single surface position, in general - the denser the spacing the more wells can be drilled from a single surface location. This results in lowering surface infrastructure costs.

Sectorisation
Sectorisation is generally a required step in the optimisation of the field development plans for CBM fields. That may be for various technical and non-technical reasons. Non-technical reasons include:
- reserves categories,
- permit outlines,
- facilities unit sizes,
- surface features, etc.

Technical considerations are related to:
- productivity of wells,
- well technology.

The technical considerations can be identified based on reservoir property maps (same as in case of preparing well technology maps – see previous section).
The authors propose a three-step approach for sector definition based on above described technical and non-technical factors. Diagram of the approach is showed in Figure 12. The approach assumes identification of technical and non-technical factors influencing sectorization in particular projects and preparing a rough layout of the required sectors based on the information gained. Subsequently technology models are assigned and analytical modelling of a given field is carried. The modelling is repeated for a number of technology concepts and well spacing assumptions. Each realization results in sets of statistics for individual areas of the investigated CBM reservoir. These allow for refinement of sector outline definition. Simulations are then re-run with updated sector boundaries. After a few iterations final sector definition is obtained.
As mentioned above the authors propose to introduce the outcomes of full field modelling as one of the elements to base the shape and number of sectors on. While it is difficult to identify sectors correctly based on individual factors influencing production (e.g. depth contour, net pay, gas content) full field modelling often allows identification of areas showing similar production behaviours. That can then act as the basis of sector identification. An example of sector definition based on outcomes of full field modelling is showed in Figure 13.
Usually high heterogeneity exists in coals, though based on the information available for individual sectors it is typically possible to identify their relative quality (e.g. based on average reservoir properties within individual sectors). The relative ranking of sectors can act as guidelines for identifying the sequence of development that results in maximizing the economical value of a CBM project.

**Drilling pace and sequence**

Drilling pace and sequence will affect the project economic profile significantly. The costs associated with drilling, completion, connection and any accompanying surface development. From the other hand also field production profile will be highly influenced by the pace and sequence of drilling. The authors realized based on multiple field cases that the pace and sequence of development can significantly affect the necessary numbers of compressors and water treatment facilities due to changes in the distribution of production rates in function of time and allocation. Therefore drilling pace and sequence should remain one of the main focus areas.

**Multi-well Simulation and Type Curve Definition**

The authors have prepared full field simulations based on analytical modelling. The simulation methods are discussed in Section “CBM dynamic modelling and production forecasting”. Gas and water production profiles are obtained for each of the wells producing from the modelled area. In the way in which the analytical model is established the principle of image wells was introduced (i.e. each well drains an equivalent drainage area, therefore whatever production is lost in some wells, is regained in other wells). This allows for averaging the production profiles of all wells introduced in a given realization or scenario into a single type profile. The moment of introduction of all wells is for this purpose normalized to the first day of production; afterwars the rates of all wells are added and divided by the total number of producing wells. This process leads to type curve definition.

It is important to introduce high number of wells for the purpose of preparing type curves. If a low number of wells is considered in the process of averaging, it can result in generation of a type curve, that may not be accurate. Discussion regarding uncertainty that can be caused by probing a limited number of samples in case of evaluating productivity of wells is given by Alessio [4].

**Economics and Concept Select Toolkit**

A key element in the concept select workflow is the relative economical comparison of alternative scenarios in a range of subsurface realizations. As a high number of scenarios and realizations are tested and compared it is necessary to use a tool
that allows for integration of the outputs of field modelling with elements of economical evaluation to carry out work in a time effective manner. The authors suggest two approaches:

- simplistic economical evaluation on single well level,
- comparative economical evaluation on field basis.

For each simulated scenario (and for each of the investigated sectors) the same economic assumptions should be made to allow the comparison of relative value of the project in various cases. The comparison of the value of individual wells can be made based on discounted cumulative well recovery (total well production discounted to present day) and CAPEX (Capital Expenditure). When the value of entire development is investigated CAPEX and OPEX (Operational Expenditure) associated with all individual elements of development (wells, compression, surface network, water storage and treatment facilities, etc.) should be indicated and introduced at appropriate stages of development and then subtracted from the benefit resulting from selling produced gas. The value, after discounting to present day, results in obtaining a first pass estimation of basic economical measures of CBM development projects. Finally, the identification of perceived best development options in the reference case and mitigation options for foreseeable issues arising throughout reservoir development can be made. These show alternative solutions if reservoir performance strays from expectations.

The workflow of full field modelling used for field development planning is visualized in Figure 14.

Figure 14: Full field modelling workflow for field development planning

Depending on the economic analysis option selected, different cost factors are included in the analysis. In case of a single well economical modelling the analysis includes only cost elements specific to the well, completion and some parts of surface infrastructure. The value of total production of a well discounted to its present value (discounted cumulative recovery) is offset against the cost associated with its drilling and operational costs (also discounted to present day). It allows for a quick glimpse first pass screening of the relative value of wells drilled in various reservoirs. When comparative economical evaluation on field basis is prepared, all major cost factors are included in the analysis. On top of well and completion cost also factors such as compression, water treatment, export lines, etc. are considered. Each of the cost elements comes with associated CAPEX and OPEX values. Total revenue is calculated based on the benefits obtained from selling gas produced from all wells introduced in a given reservoir discounted to present day. Total development cost is offset against the benefits from gas sales. It is necessary to define development schedule, as with some of the costs introduced upfront the value of the project depends to a certain extent on the points in time when additional wells are introduced. In the course of various CBM studies the authors realized that it is possible to identify wells that exhibit similar value of gas produced at various values of cumulative production and peak gas rates. A chart of equivalent economic value lines (expressed in terms of cumulative gas production discounted to present day) is showed in Figure 15. Time to peak gas rate of 2 years was selected for the plot, however it was also identified that the time to peak gas carries much lower significance when compared to UR and peak gas rate.
The chart showed in Figure 15 allows for identification of the value of gas produced from a particular well based on basic characteristics of its profile (i.e. peak gas rate and UR). This in turn allows for identifying the value of a given well when the benefit is offset against the cost of the well without repeating economical analysis for every single well profile. This translates to a higher time efficiency of a project work.

The authors suggest a comparison of relative value of a given project in various technology and spacing solutions in order to identify the preferred development option. The value of a particular solution can be expressed as a point in an X-Y plot similar to the one showed in Figure 16. The average capital cost (CAPEX) per well associated with a selected development option is put on X-axis in the figure, while Y-axis represents the average cumulative recovery of wells discounted to present day (Discounted Cumulative Recovery, DCR). Similarly value obtained from full economic analysis can be put in the plot. By plotting information regarding CAPEX and DCR associated with various development options (or the outcomes of full economic analysis in terms of total cost and total revenue) a set of points is obtained. Comparison of three drilling/completion technologies for field “A” is showed in Figure 16. Lines visible in the figure identify the minimum ratio of DCR to CAPEX required for economical development in a range of gas price. The final decision regarding development will depend on key project drivers, however the point representing optimum ratio of Discounted Cumulative Recovery (showed in Y axis in Figure 16) to well cost (showed in X axis) typically indicates the preferred technology option.
Figure 16: Discounted Cumulative Recovery (DCR) / CAPEX for field “A”
Conclusions
Due to the unique characteristics of CBM resource plays, conducting effective field development planning studies requires a remarkably different approach to the ones typically followed with conventional oil and gas fields. When compared to the typically used workflows, the approach suggested by the authors allows for maximizing the number of findings within a reasonable timeframe and ties-in individual elements of reservoir characterization, production forecasting and development planning by means of embedding value metrics in concept selection workflow. A number of elements which are often overlooked in CBM development planning efforts are also pointed out by the authors. In particular:

- importance of differentiating between variability and uncertainty (and identifying their significance on development planning),
- significance of seismic data in reservoir characterization,
- alternative approaches to reservoir characterisation and volume-in-place calculation,
- implications of using statistical analysis,
- poor time-efficiency of 3D numerical modelling (leading to limitation of the number of dynamic runs and not adequately representing the possible range of outcomes).

There are a number of improvements that the authors are planning to introduce in their workflow, these include:

- further use of simulation techniques (semi-analytical and 3D modelling) to provide additional insight into the relative location of wells and influence of various drilling and completion technologies on CBM projects,
- advances in semi-analytical modelling that will enable better representation of near-wellbore desorption and flow behaviour (including transient flow) without losing time efficiency,
- preparation a full economic analysis of entire CBM development to get additional insight into the importance of individual cost and revenue factors within ranges of uncertainty on project value,
- introduction of additional economic metrics to identify the changes in relative value of various development scenarios depending on project priorities.

While working on the workflows described in this paper the authors realized that it is desirable to integrate all the described elements into a single tool. A decision was made to build a toolkit that allows for easy reproduction of reservoir characterization, dynamic modeling and field development planning workflows in a repetitive manner. A prototype of this tool is used extensively within the company. This in turn maximizes the time efficiency of CBM project analysis and allows for investigating a high number of reservoir uncertainties and development strategies in a reasonable timeframe.
Literature


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