Case Study III: Model overview and status

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1 Introduction

This is a report to described the general nature of the hydrocarbon reservoir models to be investigated for Case Study 3 and also to provide a description of the models currently available or proposed for study as part of this case study. The report begins in Section 2 by reviewing general material on reservoir models, their purpose and common features. The first available model is of the Maureen reservoir which operated between 1983 and 1999 and for which we have full access to both model and substantial historical data for that period – this model is described in Section 3. The second model is that of the Droshky field, which has yet to enter production and there is little information about this field at present though a limited description is given in Section 4.

2 Hydrocarbon reservoir models

2.1 Overview

A hydrocarbon reservoir is a porous region of rock which contains hydrocarbons, such as oil and gas. The hydrocarbons are trapped under pressure in the reservoir in an equilibrium state (typically with water), and the system is perturbed from its equilibrium state by drilling wells into the reservoir which either extract or inject fluid from or to the reservoir. The purpose of a reservoir model is to synthesise information about the geological structure of the reservoir, its fundamental properties and the distribution and properties of the hydrocarbons in the reservoir with information about the location and operation of the wells in the model to simulate the production of fluid over time from the wells and the evolution in the state of the reservoir and the fluids it contains. See for example [3] for more details.

At the heart of a reservoir model is the representation of the geology and geometry of the reservoir itself. This is the structure on which all simulation is performed. The geological structure of the model is obtained from a complex geological model constructed prior to the reservoir model. The reservoir under study is represented by a grid, where each cell represents a region of the reservoir and its associated geological properties. The reservoir will also contain up to three different fluid components – oil, water, and gas. Consequently, each of the grid cells will contain a quantity of one or more of these fluid components. The mathematical model underlying the simulator comprises a set of fluid conservation equations which conserve the mass of fluid in the reservoir over time under the perturbations introduced by the operation of the wells. The flow of fluids between the cells of the reservoir are modelled by Darcy's Law, and since mass is conserved the sum of all flows in the reservoir is constrained to be zero. The core function of the simulator is to solve these equations under the forcing of the wells for every cell in the reservoir at each time step, and then update the state of the reservoir and iterate. We will now discuss the inputs and outputs to a reservoir model in more detail.

2.2 Input quantities

The defining feature of a particular reservoir model is the geometry of the grid on which the model is based. This grid is derived from a larger separate geological model s which is constructed using a grid of far finer resolution and must be coarsened (or "up-scaled") for use in the reservoir simulation. The grid of the reservoir model gives the reservoir its geometry and layout and attached to each grid cell are a number of basic properties representing the corresponding geological properties of the associated region of the reservoir itself. These properties are: *porosity*, *permeability*, and *transmissibility*.

The porosity (denoted ϕ) of a region of the reservoir is the fraction of void space in the material to the total volume of material. The porosity of the rock is particularly important as the void space in the rock is that which contains the fluid, and so more porous media contain more water or hydrocarbons. Porosity is measured as a fraction and so is constrained to lie in $[0, 1]$. Porosity can be assessed via direct testing of samples of the source rock, by using information gained from wireline logging instruments passed down the well itself, or by inference from seismic data. This information is then be extrapolated and interpolated to cover the entire reservoir and so a field of porosity values over the model grid is used as the input specification.

The permeability (denoted k or κ) of is a measure of the ability of fluids to be transmitted through that region. Permeability is clearly important for reservoir simulation as it represents the ease of flow of fluids within the reservoir and is again specified as a field of values over the model grid. Permeability is directionally dependent and so subscripts x, y and z are used to denote the different directions. In practice however, $x-y$ permeability is commonly treated as isotropic and z permeability is taken to be a re-scaling of k_x. This eliminates the need to assess and construct three permeability fields for the entire reservoir and reduces to considering only horizontal (k_h) and vertical (k_v) permeabilities. Permeability is usually considered on log scale, since $\ln(k)$ is often modelled as being normally distributed. Permeability is also correlated to porosity since more porous media permit more flow.

In reservoir models, it is infeasible to consider the arrays of permeabilities or porosities as representing arrays of distinct input parameters due to their sheer size. To avoid the problems of extreme high-dimensionality, these arrays are considered to be fixed and the inputs to the model (in a computer model sense) are instead a small collection of scalar multipliers which re-scale all or part of these fields. These multipliers act in one of three ways: globally – the multiplier re-scales the entire field; in blocks – the field is partitioned into distinct regions each with its own block multiplier; or locally – the multiplier acts only on a specified region of the field. An alternative approach to using this multiplier method is to attempt to parametrise a model of the entire field and use those parameters as inputs, or to include the geological model in the analysis and to consider its parameters as the inputs.

Transmissibility governs the degree to which fluids can flow from one grid cell to another. This is a derived quantity obtained from the permeability and porosity fields in conjunction with other properties of the reservoir. Consequently, it is not itself defined as an input field as with ϕ or k. However transmissibility is often modified or assigned in local regions to represent faults within the model. Faults are lines or regions of the reservoir that act as a barrier to the flow of fluids, either due to the effects of shearing due to seismic or geological activity or due to the presence of layers or regions of impassable rock. Faults therefore disrupt the contiguity of the reservoir as fluid can no longer pass from one adjacent grid block to the next. Setting transmissibility of a cell or cells to zero prevents the communication of fluids between adjoining cells and thus is a mechanism for describing a sealed fault. Thus transmissibilities enter the model as parameters associated with faults in the reservoir.

Other key quantities include the intrinsic properties of the fluids in the reservoir such as the compressibility, viscosity and density of the fluids are all important factors in the fluid dynamics within the reservoir. The relative permeabilities of oil, water, and gas are also key input quantities to the reservoir simulator. Additional input parameters include the description of the equilibrium state of the reservoir by specification of the depth of the contacts between the layers of gas, oil, and water, and also parameters involved in the specification of the aquifers associated with the model.

Name	Abbreviation	Description
Oil rate	oilrt, wopr	Oil production rate (similarly for injection)
Gas rate	gasrt, wgpr	Gas production rate
Water rate	watrt, wwpr	Water production rate
Total oil	oiltot, wopt	Total oil production (the cumulative sum of oilrt)
Total gas	gastot, wgpt	Total gas production
Total water	wattot, wwpt	Total water production
Water cut	wc, wwct	Water cut – the ratio of water to oil
Gas oil ratio	gor, wgor	The ratio of gas to oil
Bottom-hole pressure	bhp, wbhp	
Tubing-head pressure	thp, wthp	
Oil in place	fipo	Amount of oil present in the defined FIP region
Water in place	fipw	Amount of water present in the defined FIP region

Table 1: Table of output time series for each well in the reservoir model

2.3 Model forcing

The role of forcing is important in the model as both production and injection wells are operated under constraints. These well management constraints can take a number of forms, including specifying minimum producing (or maximum injection) pressures, and maximum or exact production (injection) rates. These operating constraints are part of the reservoir definition and are usually such that they mirror the historical operating constraints of the actual wells in the reservoir.

It should be emphasised that the precise way these constraints on well behaviour are handled by the simulator are not well-understood (at least by us). For example, the output generated by the simulator under precise controls (i.e. at time t oil production rate is x) does not agree with the prescribed behaviour although it is commonly in the neighbourhood of the specified values. It may be the case that these controls are interpreted as operating targets rather than hard constraints, or that there are additional interacting factors which affect how the constraints are managed.

2.4 Output quantities

Output from the reservoir simulation can take many forms. Perhaps the most useful form is the rate data which corresponds to the observed production and pressure time series. The rate information comprises time series for various quantities including, or derived from, the oil, water and gas production (or injection) rates and the well pressures. An overview of the collection of output quantities reported for each well is given in Table 1 and an example time series is plotted in Figure 1.

Time series for all quantities and every defined well in the model is produced by the simulator as output. The length of time step in these series can be pre-determined by the user by modifying the reservoir input files. Observed historical data on the well production rates and pressures is routinely gathered and so these quantities are most relevant for history matching and calibration.

In some models, the model grid is partitioned into "fluid-in-place" (FIP) regions. These regions each generate their own collection of time series describing the production from (or injection to) these particular regions of the reservoir. These regions may correspond to regions of distinct geological properties and suggest possible blocking for permeability and porosity multipliers. In addition to the standard quantities, these FIP regions produce additional output information in the form of "oil-in-place" and "water-in-place". It is believed that these quantities represent the amount of oil or water which is present in the specified region at any given time and therefore could be useful for considering the possible locations of remaining oil deposits.

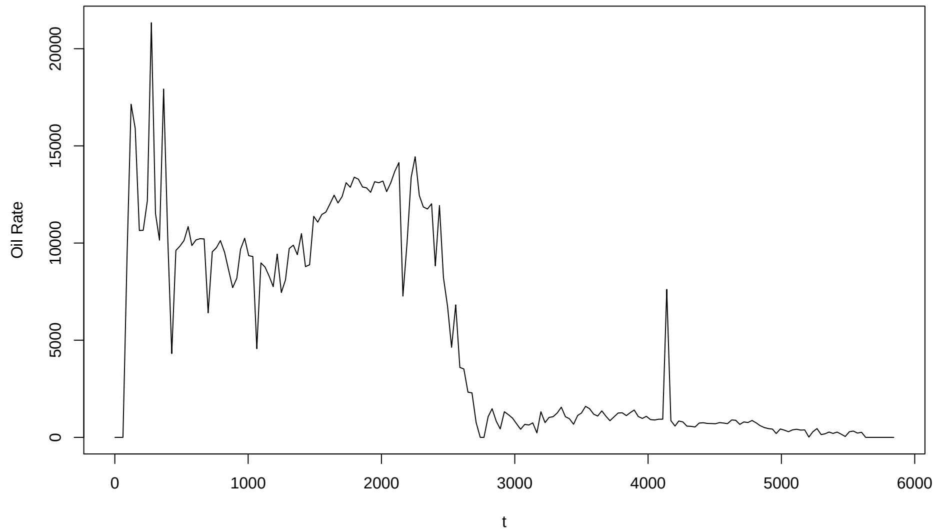

Figure 1: Example output time series for oil production rate

2.5 Simulation and software

The reservoir simulation software available to us is the Tempest-MORE Roxar [2] simulator provided by Roxar. Tempest provides a graphical interface to the simulator whereas the actual numerical simulation is performed by the MORE application. We currently have one license for the Tempest-MORE software which is bound to a machine at Durham.

Any single run of the model requires a collection of input text files which contain the reservoir specification in which the values of the parameters corresponding to this run have been inserted. These files are processed at run time by the simulator prior to execution of the simulation. Since each run requires its own particular description, executing batches of runs requires batch processing of the design matrix and the model files. This process has been automated and is executable from within R using a custom-written Java application if the input files are appropriately configured.

Output from the model is in the form of a large binary data file which requires post-processing to extract well production and pressure information. Again, a Java application has been written to process this binary data and extract relevant information into a usable format.

3 Model I: The Maureen model

3.1 Overview

The Maureen Field is a collection of three reservoirs located in UK territory in the North Sea approximately 163km north-east of Aberdeen. The three reservoirs are known as Maureen (or sometimes Maureen Palaeocene), Mary and Morag. The first reservoir model available to the MUCM case study concerns only the Maureen reservoir component – referred to as the 'Maureen model'. This model has been provided to us by Prof. Jon Gluyas of the Dept. of Earth Sciences, Durham, and Fairfield Energy who were responsible for the construction the model.

The Maureen reservoir was operated between 1983 and 1999 by Phillips Petroleum. The model contains

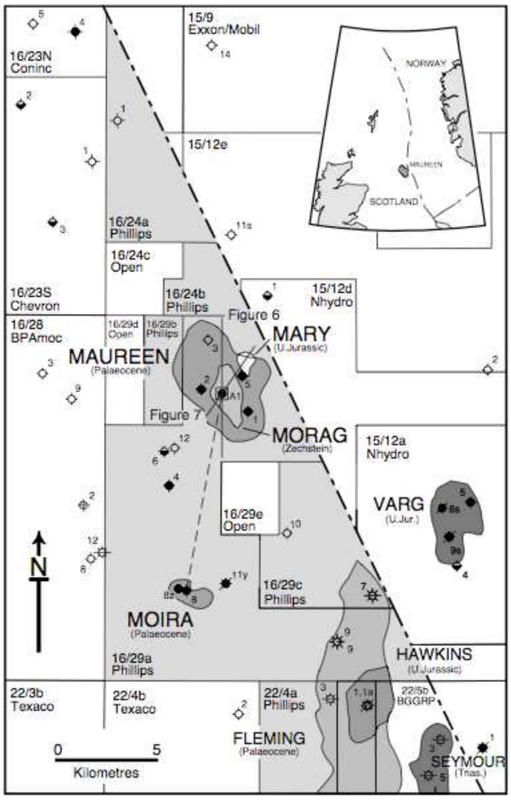

Figure 2: Location of the Maureen reservoir field (stolen from [1] – replace in public documents)

a total of 26 wells. However, not all wells are active throughout the period of study. At the start of the simulation (September 1983), only 3 of the 17 producing wells were active and the remaining producers were activated within the next two years. There are 9 water injectors in the model, most of which were active by the end of the second year of simulation (1984). A small number of the producers and injectors appear to be (almost) completely inactive throughout the simulation. Detailed information on the structure, geology and history of the Maureen field can be found in [1].

The Maureen model is the result of several iterations of history matching and refinement of the geological and reservoir models by Fairfield Energy, and is therefore believed to be already partially tuned to the observational data.

The model grid is of dimension $148 \times 113 \times 120$, and a single evaluation at this resolution takes approximately 5-6 hours to complete a single evaluation. Coarsening of the model is possible as with all reservoir models in Tempest-MORE. Coarsening substantially reduces evaluation time, for example uniform coarsening by a factor of 4 reduces evaluation time to approximately 10 minutes. The minimum execution speed appears to be around 4-5minutes which time used primarily for loading of the model rather than actual simulation. The original model of the reservoir was constructed for the Eclipse reservoir simulation software. However, since we do not have access to this software the model has been converted to a format usable by the Tempest-MORE simulation. During this conversion, it was necessary to replace the original aquifers defined by the model with alternative forms as the originals were incompatible. Since this replacement and the required parameter specifications were not part of the original model, the aquifer parameters should be treated as uncertain.

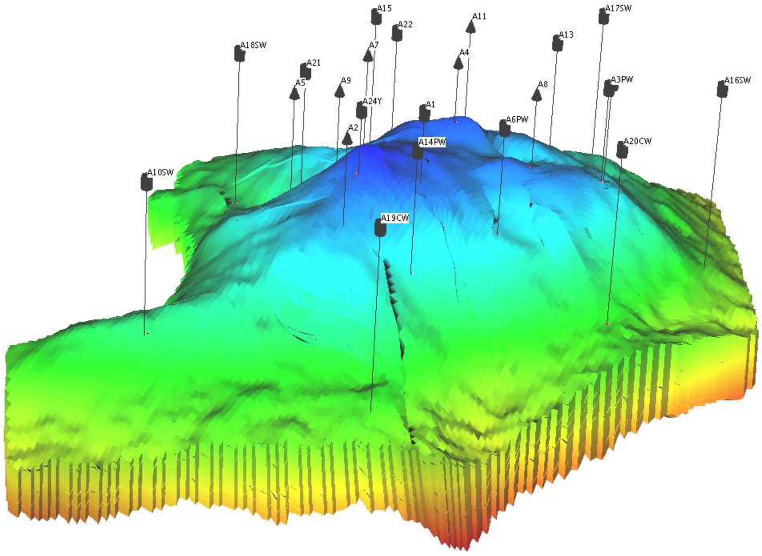

Figure 3: Visual representation of the Maureen model. Colouring is by physical depth and vertical lines indicate wells.

3.2 Model inputs

As described in Section 2, model inputs either take the form of multipliers which modify all or part of the three-dimensional permeability and porosity fields, or parameters in the specification of certain key reservoir structures, e.g. the aquifers.

At present, the model has a total of 13 input multipliers – two of which are global modifiers, and the remaining eleven are local modifiers which affect their associated property only within a defined rectangular region of the reservoir. The global multipliers re-scale the entire x and z permeability fields across the reservoir. The local multipliers appear to be local structural modifications made by the reservoir engineer to better match the data

Note that the modifiers are applied sequentially as they are encountered in the model file. Therefore, if property θ has a global multiplier value of a and a regional multiplier value of b, then within that region the parameter θ is multiplied by ab. Additionally, after performing any re-scaling of the x-permeability field (kx) but before modifying kz, the z-permeability field is initialised to equal kx. Thus, the kz multipliers are effectively controlling the ratio of $kz : kx$ rather than kz independently.

In addition to these 13 multipliers, there are a number of properties associated with the model's aquifers, which due to their ad hoc construction to facilitate the model conversion should be considered as uncertain. A summary of the model inputs is given in Table 3.2. The inputs are listed according to the sequence in which they appear in the model definition files, and thus the sequence in which any multipliers are applied.

The model also defines 14 distinct "fluid-in-place" (FIP) regions of the reservoir. It is not clear whether these regions correspond to regions of distinct geological properties and hence lead to a further sub-division of the permeability and porosity fields such that, for example, each region may have its own set of multipliers rather than using a global re-scaling of the fields.

The role of the injection wells either as inputs to the model or as forcing functions still remains somewhat unclear.

Symbol	Description	Multiplier	Min Value	Current match	Max Value
kx_1	Local x-permeability multiplier 1	$\times$		0.3	
kx_2	Local x-permeability multiplier 2	$\times$		3.0	
kx_3	Local x-permeability multiplier 3	$\times$		3.0	
kx_4	Local x-permeability multiplier 4	$\times$		3.0	
kx	Global x-permeability multiplier	$\times$		3.0	
kz	Global z-permeability multiplier	$\times$		0.3	
kz_1	Local z-permeability multiplier 1	$\times$		0.3	
kz_2	Local z-permeability multiplier 2	$\times$		0.3	
F_1	Fault 1 transmissibility multiplier	$\times$		0.0	
F_2	Fault 2 transmissibility multiplier	$\times$		0.0	
ϕ_1	Local porosity multiplier 1	$\times$		2.0	
ϕ_2	Local porosity multiplier 2	$\times$		0.5	
ϕ_3	Local porosity multiplier 3	$\times$		0.5	
$Aqk_{1:2}$	Permeabilities for both aquifers			200.0	
$Aqp_{1:2}$	Porosities for both aquifers			0.2	
$Aqr_{1:2}$	Radii of both aquifers			20000.0	
$Aqt_{1:2}$	Incidence angles for both aquifers			180.0	
$Aqh_{1:2}$	Heights of both aquifers			200.0	

Table 2: Summary of inputs to the Maureen model (with extension to FIP regions if appropriate)

3.3 Model outputs

Model outputs take the form of monthly time series of the standard output quantities for every well as described in Section 2. For each of the 14 FIP regions defined in the model, we obtain the same time series as for the wells (as a re-aggregation of the same quantities) but also receive the two further oil- and water-in-place outputs.

3.4 History

Historical data is available in the form of monthly time series for each of the principal production quantities, i.e. oil and water rates and cumulatives. Historical data on pressures has been recorded, but we do not have access to this information at this time. No historical data is (or even could be) available for the oil/water-in-place quantities.

3.5 Interesting questions

- **History matching and forecasting** – The primary goal of the analysis of this model is to perform history matching/calibration of the model to the available data. Since we already have the working match of the model, determining the uncertainty associated with thes match, and also whether there are any superior matches to the history will be of interest. Forecasting will be a key means of assessing the adequacy of the match by partitioning the data, history matching on the first portion and forecasting the second. s
- **Investigate possible location of remaining hydrocarbons** – The reservoir has been inactive since 1999 and since that time two additional exploratory wells have been drilled in an unsuccessful attempt to locate any substantial remaining oil deposits. Using the reservoir simulator to assess the distribution of hydrocarbons in the reservoir would be of interest.

Further topics for research which may lie outside the scope of the case study include:

- **Investigation and inclusion of the geo-model in the process** – As mentioned in Section 2, the reservoir model is the second stage of the matching process. The geological model of the reservoir is constructed first from appropriate data, that model is then coarsened to obtain the basic structure of the reservoir model. Assessment of the sensitivity of the reservoir model (and ultimately the best match) to uncertainties in the geo-model is an open question.
- **Introduction of new wells** – Given the reservoir state at the present day, identify appropriate locations to site further production wells. This will involve trading off the cost of sinking new wells or performing other further exploration with the amount of oil expected to be recovered. This is clearly a decision problem which may be worth investigating in MUCM2.

4 Model II: The Droshky model

4.1 Overview

In contrast to the Maureen field which is no longer operational, the Droshky field has yet to enter production. The Droshky field is owned by Marathon, a US-based oil corporation, and is situated in the Gulf of Mexico 137 miles south-south-west of Venice, Louisiana. Marathon estimates that the field contains 80 to 90 million barrels of oil equivalent, making this a serious commercial application. The reservoir is not yet producing, it is likely only geological data and limited actual production data from the appraisal wells will be available. Actual production from the field is expected to begin during 2010. The model or the data for the Droshky is not yet available, but will be provided by Marathon via Bob Parish and Roxar.

References

[1] Chandler, P. M. and Dickinson, B. (2003), "The Maureen Field, Block 16/29a, UK Central North Sea," in *United Kingdom oil and gas fields commemorative millennium volume*, eds. Gluyas, J. G. and Hichens, H. M., London: Geological Society of London, vol. 20 of *Memoirs of the Geological Society of London*, pp. 587–601.

[2] Roxar (2008), *MORE 6.5 Technical Reference*.

[3] Thomas, G. W. (1977), *Principles of Hydrocarbon Reservoir Simulation*, Tapir.