Honing unconventional technology for the Middle East

The latest modelling tools to improve unconventional reservoir stimulation are now being tailored for the potential new plays opening up in the Middle East, writes Dave Sobernheim, Principal Engineer in Schlumberger’s Unconventional Resources team.

HORIZONTAL well drilling, multistage stimulation and next-generation advanced modelling tools are already enabling companies to harness unconventional oil and gas reserves around the world. Now, the Gulf region’s unconventional deposits could be about to be opened up. Maximising the potential of a massive resource base, which until recently was considered too impermeable to produce economically, will require the latest and best science to be applied.

In the 1930s, initial exploratory wells were drilled in the Dharan area of the Arabian peninsula and tested with high absolute open flow (AOF) potentials using simple barefoot completion designs. Few then would have foreseen the days when horizontal drilling and massive hydraulic fracturing in multiple stages per well would be used to attempt AOF flowrates of a new generation of oil and gas resources lying underneath these vast reserves of unconventional shale source rocks, along with associated tight gas sands and low-permeability carbonate reservoirs.

Producing now for more than 70 years, most of the world’s oil reserves lay in this region. Yet almost because of their very productivity and resource abundance, oil and gas prospectors are now moving one step up the oil generation chain—to the original organic mudstone rocks that serve as the source rock for this abundance. Organic-rich Silurian age shale source rocks are prevalent from the Moroccan Blue Atlas Mountains across the expanse of North Africa and the Sahara, across the Nile, and through the Arabian Peninsula to the Gulf region. These original source rocks for so many massive oil fields are now the subject of intense exploration and evaluation activity to discern if economic flow-rates of gas and oil can be generated from these resources.

Classical job design

Conventional job optimisation began with semi-steady and steady-state type curves. In the 1960s, hydraulic fracturing stimulation designs were designed in terms of fracture half-length (xf), conductivity (kfw) and drainage area penetration ratio (xf/xe). Engineers looked at the potential fold-of-increase (Js/Jo) from radial fracture to stimulated condition possible by creating conductive fractures in the reservoir. Through the use of classical fracturing design tools based on 2-D fracture geometry or 3-D, appropriate stimulation designs to obtain desired lengths and conductivities could be made in a straightforward manner.

Once a design was known, analytical or numerical simulation would be run to forecast the production rate. “What-if” scenarios for various job sizes and pump rates could be used to optimise the job treatment design. By linking a fracturing simulator model with a production forecast model, a maximum net present value (NPV) design could be chosen. This required determining job costs on a material and horsepower basis, and product revenue from an oil and gas price forecast. This has been the means used to optimise job design until unconventional reservoir development began in earnest in 2001 and fracturing complexity entered the picture.

Understanding unconventional behaviour

When early operating companies first unlocked the Barnett Shale in the US with horizontal well drilling and multistage fracturing, it quickly became apparent that many classical design models were not adequately modelling the process. This was primarily noticed as far-field microseismic monitoring began to be routinely used to monitor stimulation treatments and create a map of the shear failure events occurring during pumping operations. The maps usually differed substantially from a typical bi-wing fracture model prediction, containing a significant complex lateral component sub-parallel to minimum in-situ stress, as well as the usual perpendicular component to minimum stress.

With time, it became apparent that conventional models were not capturing the complexity of the fracturing process so many design engineers gradually returned to a spreadsheet, statistical-based technique for determining job volumes, rates and perforation staging locations, abandoning conventional, P3D and planar models.

With this reversion to simplified job-design techniques, optimisation of the jobs became difficult on the rigorous, predictive basis used in the past. Instead, new shale fracturing designs relied on offset well and microseismic-driven analysis to determine the estimated stimulated volume (ESV) for various job sizes, relating ESV to well productivity. The larger the ESV, the better the productivity of the well, and stimulation designs that created a large ESV, as seen on microseismic, were repeated on subsequent wells to achieve maximum stimulation.

Analogously, if microseismic was unavailable, production response was used to validate if a particular job design was successful. This was a relative measure, however, as there was no clear way to determine if the true well potential was realised. It was the best means that was available under circumstances where classical, predictive fracturing models were not accurate. Techniques utilising the ESV as a region of “super-permeability” in numerical reservoir simulation models were used to try and match productivity of the wells. However, it was difficult to decide what the enhanced permeability region truly represented in a physical, quantitative manner.

Optimisation: the new challenge

Because of the difficulty in obtaining rigour in job design, prediction and economic evaluation using conventional models, new modelling technology has been developed to attempt to remedy the situation and return to the approach of treatment optimisation via varying pumping design and determining the effect on productivity and thus economics.

One available technique is known as the wiremesh fracturing simulator model, which is the mathematical equivalent representation of the Hydraulic Fracture Network (HFN), expanding as an ellipsoid volume with increased injection. Wiremesh models are capable of coarsely over-laying microseismic-measured dimensions, and thus history matching is possible to calibrate a model. While effective for environ-mental, the semi-analytical engine, wiremesh models suffer from an absence of a true relationship to physical reality, though they are a step-up from the classical bi-wing models.

More rigorous modelling techniques are needed to create a better means of utilising new advanced well measurements, including anisotropic rock mechanical and petrophysical properties. Accurate predictions must be made of discrete hydraulic fracture dimensions, including length (xf), width (xe), and conductivity (k, w) over complex...
dimensions (i by j) related to natural fractures and other textural rock features as described in the Discrete Fracture Network (DFN) model. In this effort, one important consideration is to integrate this new hydraulic fracture design optimisation tool with existing geoscience workflow platform software tools.

The Petrel E&P platform software is used due to its ability to build a 3D geocellular model capturing the rock heterogeneity that is a key characteristic of unconventional reservoirs. Building a consistent earth model required for better fracture modelling is possible through cross-validating multidomain data from geophysics, geology, geomechanics, petrophysics, drilling and reservoir. Importantly, building the shared model for a successful design and evaluation optimisation of the pumping treatments in the context of overall reservoir management has led experts in disparate disciplines to work together on one common single platform.

This has culminated in a new Ocean plug-in application for the Petrel earth model, reservoir-centric stimulation design software known as Mangrove. This has been developed to fill the void in complex fracture design tool modelling capability. Key to its function, crossing-criteria equations have been developed to model the interaction between hydraulic fractures and natural fractures (or, generically, planes-of-weakness) in the reservoir as described in the DFN model. Mangrove software analytically models this interaction in terms of various parameters including angle-of-incidence $\theta$, net pressure $\Delta P$, fluid viscosity $\mu$, and minimum-to-maximum stress contrast in the reservoir ($\sigma_{\text{min}} - \sigma_{\text{max}}$). These equations have been substantiated via laboratory large-block scale tests at the TerraTek geomechanical centre in Salt Lake City, Utah.

**New tools for the Middle East and beyond**

Schlumberger is studying applications for Mangrove software across the Middle East for optimisation of multi-stage fracturing in tight sandstone, tight carbonate and shale-gas reservoirs. The company has Mangrove-trained production and stimulation experts in Saudi Arabia, Oman, Egypt, India, the United Arab Emirates and Qatar. Utilisation of this programme for completions optimisation and performance prediction is intended to accelerate the learning curve for development of these vast unconventional reservoirs.

While not mandatory to the workflow, microseismic mapping is important to help provide calibration of the hydraulic fracture growth patterns to the simulator-predicted geometry and thereby validate results and increase confidence in subsequent wells. Oil and gas rate production performance is the final measurement, and predictive-versus-actual results in Middle Eastern reservoirs will eventually provide full confirmation of this optimisation process. Initial reservoir characterisation efforts are showing high total organic content (TOC) values above 5% and tremendous resource potential in many areas, but much additional characterisation work remains to be done.

While still in its early days in the Middle East, Mangrove software has been applied successfully in other areas, including recently published examples in the US and China, as well as Argentina and elsewhere.

For two operators in the US Marcellus Shale, the Mangrove workflow has been successfully applied in optimising job design, perforation location and staging to yield production increases of over 50% from baseline offset well performance. In these cases, advanced sonic logging was deployed as part of the measurements package to calculate anisotropic rock properties along the horizontal lateral ($\sigma_{\text{max}}$, $\sigma_{\text{min}}$), and the completion advisor module utilised to group perforation clusters and stages alike into comparable sections of rock. Microseismic activity was monitored and verified comprehensive stimulation across the stage clusters, compared with offset wells where this technique was not utilised and only a portion of the clusters received stimulation in each stage.

In China’s Ordos basin, the successful evaluation of reservoir quality (RQ) and completion quality (CQ) by geoscientists is allowing job optimisation via the Mangrove software workflow tool. RQ/CQ calculations are used in Mangrove software to describe the capacity of the reservoir to produce economical flow-rates of hydrocarbon (RQ), and the propensity of the reservoir to respond adequately to massive hydraulic fracturing stimulation (CQ). Both characteristics are required to generate economic success. Schlumberger engineers applying this workflow for PetroChina generated over 50% greater production in a horizontal well versus the best offset, and over four-fold production increases on two pilot vertical wells, compared with conventional vertical wells in the field.

**A promising future**

Beginning with early classical reservoir engineering, hydraulic fracturing has always benefitted from systematic design and analysis methods to optimise well and project economics. While the complexity seen in unconventional resource development has recently upended classical design methodology, new technologies, including Mangrove software, are allowing a return to rigour in optimisation capability through an accurate modelling of hydraulic fracturing geomechanical propagation and productive behaviour in ultra-low permeability and organic source rocks. Vast trapped potential in the Silurian and other shale source rocks in the Middle East are in the early stages of receiving the advanced optimisation now on offer, so the future holds great promise.