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The Application of Compositional Modelling to the Integration of Realistic Re-Stimulation Strategies and Unconventional Shale Gas Supply Chain Optimization

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Shale gas supply chain network optimization received increased focus following the global economic recession that occurred between 2014 and 2016. Increasing the efficiency of upstream and downstream operations while maximizing shale gas project profitability became the best strategy for offsetting low oil and gas prices. This work suggests a multidisciplinary approach for the design and optimization of a given shale gas supply chain network. This integrated approach incorporates realistic drilling, completion and stimulation strategies through the compositional modelling of a geologically heterogeneous shale gas reservoir.
Previous work in this area considered mixed integer linear programming (MILP) optimization models with minimal consideration for pragmatic shale gas reservoir development. This resulted in grossly over-estimated shale gas project NPV's and impractical payback times. A 3D coupled compositional reservoir model is constructed using CMG's software suites, to simulate drilling, completion, stimulation (DCS) and well pad production processes for a supply chain network. Utilizing geological parameters, characteristic of the Marcellus shale, this model generates realistic wastewater and gas rate decline profiles as well as the temporal variation of shale gas components, which are inputs for Quasi-MINLP optimization in General Algebraic Modelling System (GAMS). The results show that the optimization of shale gas production and project NPV are rarely obtained from singular and mathematically convenient well pad design configurations. Reservoir heterogeneity and realistic DCS strategies have a huge influence on the techno-economics of shale gas projects. This paper reveals a conservative and yet credible approach to optimizing well pad designs, waste water recycle structures and supply chain networks, while minimizing shale gas re-stimulation costs.

1. Introduction

Production from Marcellus shale began in 2007 and has quickly increased to nearly 16 BCF/day, making it by far the largest gas play in North America. Much of the value derived from Marcellus is from NGL sales, mainly from the Liquids rich area where drilling is currently most active. In 2014, the Marcellus contributed to serving an over supplied gas market, which precipitated in gas price reduction and increased pressure to reduce the number of wells being drilled in the shale play (EIA, 2016). Shale gas exploitation has flourished over the past decade and this has made its supply chain optimization the subject of research in many institutions.
MILP models are commonly used to design shale gas supply chain networks as well as evaluate the profitability of shale gas projects. Non-linear MILP models became preferable for resolving complex bilinear variables prevalent in Total Dissolved Solid (TDS) waste water formulations (Yang et. al., 2015) or in the long-term planning of shale gas supply chain networks (Cafaro et. al., 2014). Parametric studies of well pad designs by Calderon et. al. (2015) were used to formulate an economic evaluation of shale gas resources, and other optimization frameworks have focussed on integrating water management structures with shale gas supply chain design and planning (Gao and You, 2014; Guerra et. al., 2016). More recently, a disjunctive MILP formulation was applied to two case studies to show how re-fracturing can increase the expected recovery of a well and improve its profitability (Cafaro et. al, 2016). Unconventional shale gas supply chain optimization is a multidisciplinary techno-economic problem (Chebeir et. al, 2016), which can be accurately

solved through the integration of reservoir engineering and MILP process optimization. This work uses a 3D coupled compositional model that incorporates a realistic DCS well pad strategy, in order to develop input for supply chain network optimization. This framework, if adopted, avoids the pitfalls of inflating project NPV's and becomes a pragmatic tool for actual shale gas development projects. The integrated methodology presented can also be applicable at any time during the planned horizon of an existing shale gas supply chain network, using assisted history matching or traditional decline curve analysis. Shale gas models built in general, must account for the shape and heterogeneous characterization of the shale reservoir in question, in order to come close to realistic output data. Re-fracturing is often recommended at the ecomonic production limit of shale wells, as it has the potential to resuscitate natural fractures, extend existing fracture network, replace low conductivity or embedded proppant, and compensate for rock creep deformations (Asala et. al., 2016).

2. Background

The development of shale gas resources requires strategic and operational decisions concerning drilling, completion, stimulation, and re-stimulation. Others key decisions include: design of the supply chain network required for shale gas products' transportation and distribution, location and design of compression stations and facilities for processing wet gas, fresh water sources for stimulation operations, and recycle/disposal options for generated wastewater. Figure 1 is a pictorial representation of the shale gas superstructure used in this papers' case study.

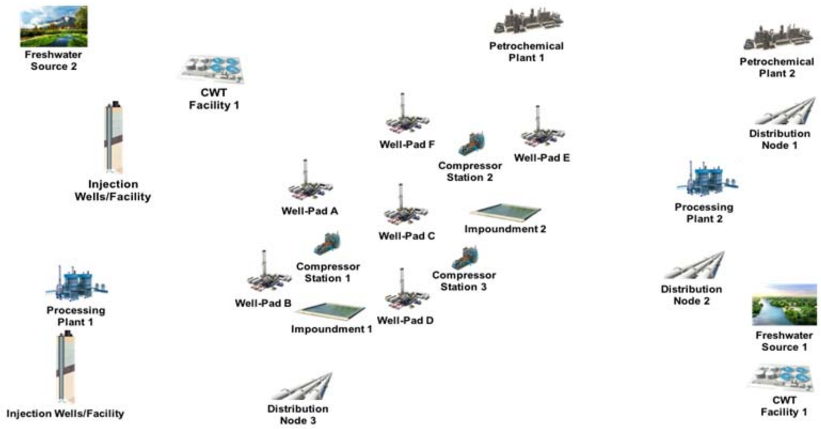

Figure 1: Shale Gas Supply Chain Superstructure for the Marcellus Case Study

3. 3-D Coupled Compositional Reservoir Model

The compositional model developed in this work is a two-phase reservoir model with logarithmically spaced, locally refined dual permeability (LS-LR-DK) 7 x 7 x 1 frac grid refinements. A dual permeability (fully implicit) model is used for an accurate representation of primary permeability in induced fractures and secondary permeability in the natural fracture system. The superstructure containing the well pads was modelled with an 80 x 100 x 10 orthogonal corner point grid block system in CMG's Builder. The relative locations of each pad was put into consideration in the development of the reservoir model. Actual pad locations were used in GAMS model development. Petrel Geology and Modelling software had been used to develop the stratigraphic and structural 2D maps used for the case study reservoir. This was then imported into Builder to develop the 3D reservoir model as seen in Figure 2. Based on the proximity of the well pads in the case study model, we assumed a spatially constant shale gas composition in the reservoir. The shale gas reservoir was modelled as a Wet Gas Reservoir (WGR) and the compositional fluid model was created using CMG's WINPROP. CMG's GEM is an Adaptive-Implicit EOS compositional and GHG simulator, appropriate for modelling multi-component fluid flow through porous media. Multi-component Langmuir isotherm parameters were used to model adsorbed shale gas composed of (CO_2, H_2S, n-C_1 to n-C_5, i-C_4, i-C_5, C_7^+). Gas desorption contributes significantly to the flow of shale gas through the pore system as pressure depletion occurs.
An attempt was made to incorporate rock poroelastic deformation in the generation of hydrocarbon and water decline rate profiles. Since fracture conductivity drops as pressure drops in the fracture, pressure dependent permeability needs to be incorporated while simulating hydrocarbon production. Hydraulic fractures were modelled as multiple planar fracture stages along the horizontal well lateral with each induced fracture height not necessarily covering the 71ft of net pay. We assume that the efficiency of proppant placement and rock

stimulation is not the same for all wells in the same pad, even though hydraulic fracturing operation for two pads may be carried out by the same designated frac crew. GEM was run to simulate fracturing, re-fracturing and multiple re-fracturing scenarios. The effects of rock creep on production was not included in this work.
The theory of Linear poroelasticity was originally developed by Biot in 1935 to help describe linear isotropic poroelastic processes. It describes the constitutive relations for the porous solid matrix and the pore fluid which make up the poroelastic medium. A combination of these constitutive relations, Darcy's transport law, the solid equilibrium law, and the fluid continuity equation all govern rock deformation and fluid flow processes in reservoir formations. Neglecting body forces, a uniaxial plane strain deformation process (typically occurring during production from shale gas reservoirs) can be mathematically described by Eq(1) and Eq(2).

$$2\nabla G\epsilon_{ij} = \nabla(\sigma_{ij} - \sigma_{ij}^{o}) - \upsilon\nabla\sigma_{kk}\delta_{ij} + \alpha(1-2\upsilon)\nabla(P-P_o)\delta_{ij} \tag{1}$$

$$\frac{K}{\mu}\nabla^2 P - \left(\frac{\alpha-\emptyset}{K_s} + \frac{\emptyset}{K_f}\right)\frac{\partial P}{\partial t} = \left(1-\frac{K}{K_s}\right)\frac{\partial(\nabla\cdot \mathrm{u})}{\partial t} \tag{2}$$

The kronecker delta is defined as, $\delta_{ij} = \begin{cases} 1\ ;\ i=j \\ 0\ ;\ i\neq j \end{cases}$ and α represents Biot's poroelastic co-efficient. P is pore pressure, G is drained shear modulus, ϵ_{ij} is a strain tensor, υ represents Poisson's ratio, σ_{ij}^{o} is an initial effective stress tensor and σ_{ij} is a final effective stress tensor. K represents stress dependent permeability and μ represents fluid viscosity. K_s *and* K_f represent the grain and fluid bulk moduli. $\emptyset$ is instantaneous porosity, and u is the displacement vector.

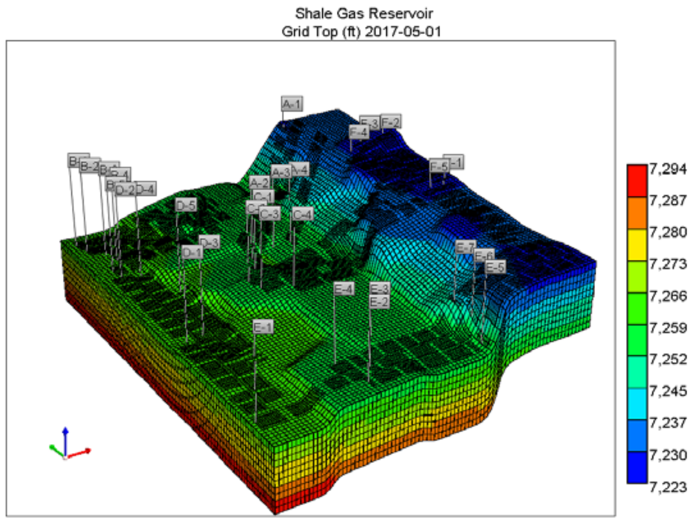

Figure 2: 3-D Compositional Reservoir Model with 30 fractured shale wells

4. Drilling, Completion and Stimulation Strategy

A Supply chain network design incorporating realistic DCS strategies should at most be modelled with 1-month time increments. This gives a higher resolution of the simultaneous operations that take place during DCS, flow back or possibly future re-stimulation operations. The EOS simulator and GAMS model will better capture the step-time taken to drill, complete, stimulate and flow back each well in the respective pads. It will also shed more light on the water recycle interaction between each pad during alternating re-frac operations. When computational constraints are a concern during project planning, multi stage optimization can be adopted. In this case 1 month is used whenever DCS or re-stimulation is occurring but production operations use 3-month time increments. This works MILP optimization scheme utilizes a DCS strategy that is pre-determined from reservoir modelling and simulation. Decisions concerning the number of wells per section, well trajectory, lateral placement and well spacing in a shale reservoir are finalized by a multi-disciplinary effort: rock mechanics, geology, geophysics, petro physics, reservoir and drilling engineering. Given stratigraphically heterogeneous reservoirs, well logs are used to determine the more potentially productive layers. These layers eventually become the landing zone for shale wells in each shale section. These layers or zones must have an economical net pay thickness and the best petro physical properties (matrix and NF porosity, and permeability, hydrocarbon saturation). They must also have the most desirable natural fracture

characteristics – extent, size, density, orientation - coupled with desirable zonal geomechanical properties (rock brittleness, Young modulus, fracture toughness, in-situ horizontal stress and layer stress contrasts).
CMG's Builder was used to develop a Marcellus shale gas reservoir with distinct rock layers, faults and boundaries. Given the designated landing zone and specified fracture stage spacing's, a simple optimization problem is set up in CMOST to ascertain the number of wells and well spacing per section, that optimizes hydrocarbon recovery. The final reservoir model is built with all the wells according to the result of this rational optimization. This could have also been determined heuristically. After construction of shale wells in the model and allocation into well pads, pragmatic possibilities for the order of execution of DCS were developed. Practically, the order and execution of batch drilling and completion programs should depend on the number of and time duration drill rigs are leased out to operator, comparative productivity of well pads, operating economic conditions, relative proximity of well pads to each other, pressure and hydrodynamic communication that may potentially exist during production from each well, amongst other factors. The most profitable wells i.e. well's in pad C and D were recommended to be drilled first using the two drill rigs available for the project.
Technological advancements and the increased efficiency of drilling shale wells suggest a 15-day turnaround for drilling and completing a typical well in the SW core or Liquid rich region of the Marcellus Shale (EIA, 2016). In this work, we assume rig move-over time between pads is negligible (3 days) and 4-7 wells are planned to be drilled per pad. The 30 wells in Pad A through F will be batch drilled strategically and simultaneously, using two drill rigs (epoh_1 and egroj_11) and drill times will depend on well MD and other extraneous and unplanned considerations encountered while drilling. Wells in pads C, F and E will be drilled with epoh_1, while wells in pads D, B and A will be drilled with egroj_11, in that order. It will take 15 days on average to drill consecutively each of the 4 wells in pad C and pad A. Each of the 5 wells in pad D, F and B will take an average of 12 days to drill. Each of the 7 wells in pad E will take 13 days. After drilling is complete, final well completion, stimulation and flow back of each well occurs. Batch stimulation operations will be adopted to increase operational efficiency and due to other technical concerns. Well stimulation will be contracted to four different frac service operators (with 24 hour crews), and zipper fracturing of wells will be executed in each pad. Wells in pad C are designed for 35 frac stages, while wells in pad B and D had a mix of 30 and 35 frac stages. Wells in pad E and F were designed to have between 25-30 frac stages. The 4 wells in Pad A wells were designed with 25, 27, 30 and 35 stages. According to EIA (2016), most onshore shale plays take approximately 30-45 days for 90% of fracturing flow back water to be retrieved. If approximately 7-10 frac stages can be zipper fractured daily by the 24-hour crews on each pad, final completion, stimulation and flow back of wells in all 6 pads will take approximately 2 months each. According to EIA (2016), most multi-well pads in the Marcellus have 4-6 wells but when there are multiple stacked zones, some pads are planned to have 12, 16 or 24 wells. Batch re-fracturing programs were implemented even though realistically not all wells in the same pad have the same decline in production. Practically, not all stages that are designed for initial fracturing are actually fractured. Possible screen out or high pressures encountered in the field during fracturing can cause some stages to be abandoned. Re-fractured shale wells were modelled as having relatively "repaired" older fractures plus the new fractures that resulted from narrowing cluster spacing or fracturing stages that were skipped or incompletely fractured during initial hydraulic fracturing. The improved older frac stages still contribute, albeit weakly, to production relative to the newer frac stages due to an inherent depletion of hydrocarbon in the previously stimulated zone. The re-fractured zones between the clusters of the older fracture stages were modelled as contacting virgin rock, having extended secondary fracture networks, longer re-frac half lengths, relatively bigger frac widths, and higher fracture (proppant) conductivity. By the time re-fracturing is implemented on older wells, more sophisticated fluid/proppant systems and better diverter technology will result in better results compared to the first hydraulic fracturing. Siebritis et. al., (2000) suggested that the optimal planning of re-frac operations should consider the timing of stress reorientation. Roussel and Sharma (2012) further determined that mechanical and poroelastic effects influence optimal re-fracture times and the evolution of the stress reversal region after this optimum time. Asala et. al. (2016) suggested that predominantly the timing of re-fracture treatments should coincide with the objective of maximizing oil and gas production.
In this paper, we adopt a re-fracture philosophy where all wells in a designated well pad are fractured at the same time, when they approximately attain the economic threshold decline rate of 15 % of IPR. Practically, not all wells will respond favorably to re-fracturing. This work also assumes economic operating conditions are based on reliable projections over the project planning horizon and considers five main stimulation strategies as input for MILP decision making and strategic planning. They include; No re-frac operation, re-frac timed at 15 % of IPR, re-frac timed before 15 % of IPR, re-frac timed at after 15 % of IPR and multiple re-fracturing operations. Natural gas price forecast played no significant part in the decision to re-fracture, as such was the case in the most recent economic downturn. Each pad's location, total number of wells, well orientation, well spacing, number of frac stages, and well lateral lengths were pre-determined from 3D reservoir simulation. For instance, pad A was optimally designed to have 4 wells, with 30, 35, 27 and 25 stages drilled with inclined

orientations to the horizontal reservoir plane. Pad C was designed to have wells with 35 stages each mostly due to the minimal compartmentalization in the region where shale gas was in place.

5. Quasi-MINLP Model

The strategic planning model formulated partly uses a Quasi-MINLP technique and considers a planning horizon of 10 years discretized in 1-month time steps. Formulation was developed to accommodate multiple well designs, i.e. different number of stimulation stages, well lateral lengths and orientation, according to the specific shale gas development program. The reservoir development program was pre-determined according to reservoir simulation results. After implementing the 5 realistic DCS strategies in the model, output data including water and hydrocarbon rate decline profiles were exported and post processed for input to GAMS. The transformative expression for defining production from each well-pad, in a given time period is given in Eq(3). Where $N_{i,d,q,t}$ is the total number of wells at well-pad, *i* with design, d

$$SP_{i,t} = \sum_{d\epsilon D} \sum_{q\epsilon Q} \sum_{\tau=1}^{t-1} N_{i,d,q,\tau} \cdot spr_{i,d,q,t-(\tau+m)} \quad \forall\, i\epsilon I, t\epsilon T \tag{3}$$

and operation, *q* developed in time period, τ. $spr_{i,d,q,t-(\tau+m)}$ represents the shale gas production rate profile of each well. Parameter τ is obtained from the DCS strategy and it ensures correct computation of the relative age of each well. Parameter m defines the start of production for each well, which is also related to the DCS strategy implemented in the reservoir simulator. As wet shale gas is produced from each well pad, it is transported to several compressor stations, strategically located to assist transportation of shale gas to a designated processing plant. Eq(4) describes the nodal material balance. where $FJ_{i,j,t}$ represents the flow of

$$SP_{i,t} = \sum_{j\epsilon J} FJ_{i,j,t} \quad \forall\, i\epsilon I, t\epsilon T \tag{4}$$

shale gas from well pad *i,* to junction node, *j* during time period, *t*. Hydrocarbon flow rates can be obtained for each component of wet shale gas according to a junction node material balance described in Eq(5).

$$\sum_{i\epsilon I} FJ_{i,j,t} = \sum_{p\epsilon P} FP_{j,p,t} \quad \forall\, j\epsilon J, t\epsilon T \tag{5}$$

where $FP_{j,p,t}$ stands for the flow of shale gas from junction node, *j* to separation plant, *p* during time period, *t*.
Other constraints related to the infrastructure required for the production and transportation of shale gas, water management, pipeline and facilities capacities among others, are not presented. However, they are taken into account in the development of the optimization model. The maximization function used in this works' MILP formulation is given by Eq(6). Where NPV is computed as cashflow $CFLOW_t$ minus well capital investment, $CAPEXW_t$, all discounted at dr, minus the initial capital investment, $CAPEXI$.

$$Max\ NPV = \sum_{t\epsilon T} \frac{CFLOW_t - CAPEXW_t}{(1+dr)^{t-1}} - CAPEXI \tag{6}$$

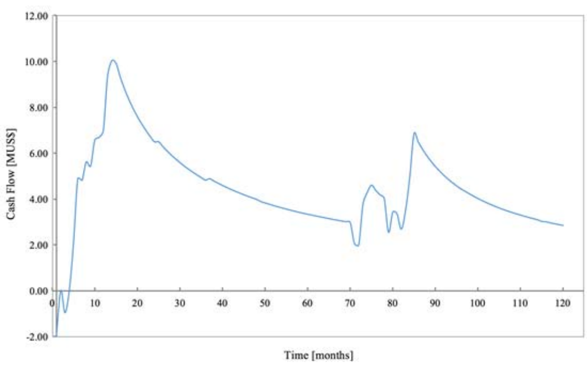

Figure 3: Cash Flow variation over planning horizon

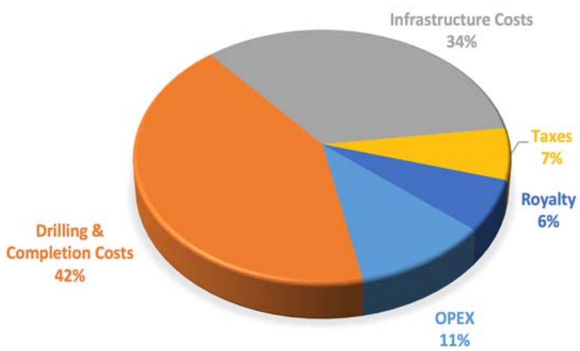

Figure 4: Pie Chart showing distribution of Project Cost

6. Results

The CMG Model was run using 5 different DCS strategies. Only 2 of these strategies were compared in this section, Re-fracturing at 15% and no re-fracturing. Model was built using an Intel® Xeon® CPU @ 3.10GHz, 64 bit operating system with 32 GB of RAM. Simulation time was less than 6 hours for each realization. Re-fracturing was executed in all the wells in pads C, D, B and in some wells in pads F and E. All wells in pad A were deemed unsuitable candidates for re-fracturing. Realistically, the decision to re-fracture candidate wells in pads E or F will depend on if pressure interference amongst sister wells will affect re-frac operations. All wells in these pads may be re-fractured or none. Figure 3 shows the cash flow realizable during the project. Shale gas project NPV was estimated at US$ 73.55 MM. Figure 4 shows the distribution of the major costs associated with the optimal supply chain network. A water use mix plot and a tabular representation of the optimal DCS strategy, approved by the MILP model, was developed but not presented in this paper.

7. Conclusions

The integrated framework proposed in this work is relevant for optimizing a shale gas supply chain network that is being planned or already existing. 3-D compositional models should be constructed to represent heterogeneous shale gas reservoir(s) under consideration for supply chain optimization. Strategically implementing realistic DCS and re-stimulation strategies over the project's planning phase gave an accurate projection of the cumulative amounts of recoverable water and shale gas derivatives. This improved the input data utilized in the MILP optimization of the supply chain network. Implementing an optimal DCS strategy initialling independent of the MILP formulation, reduced overall computational time, maximized project profitability and prevented erroneous feedback of payback time. The identification of potentially more productive wells from reservoir simulations assisted with making more informed decisions on candidate wells for re-fracturing. The final decision to re-fracture wells should incorporate this techno-economic approach and other special considerations such as shale gas reservoir quality, effective well stimulation index and completion efficiency. Current work considers a spatially heterogenous shale well pad system and compares the results of supply chain optimization using this papers' integrated approach and that of pure MINLP models.

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