Petroleum Experts

Engineering & Geological Software Development

SPE-201746MS

Leveraging Integrated Production Modeling and Digital Platforms to Maximize Liquid Yield and Reduce OPEX from Liquid-Rich Marcellus Reservoirs – A Field Study

Hemant Kumar[1], Tej Bhinde[2], Edgar Dias[1], Travis Billiter[1]

[1]Chevron Corporation [2]Petroleum Experts Inc.

ABSTRACT

This work describes the use of integrated production modeling (IPM), along with digital platforms, as reliable tools to increase liquid yield, reduce operational expenditures ($/BOE) and maximize the project's net present value (NPV) in the Appalachian Basin. The results of the work, as applied to a real field show that the liquid yield for the gas condensate produced fluids can be increased by 3-5%; compression energy and process heating requirements can be reduced significantly.

The condensate to gas ratio (CGR) in Marshall County, West Virginia (WV) changes rapidly from southeast to northwest. For example, on a single pad (8-10 wells) the CGR of the northwestern wells is ~40% higher than the CGR of southeastern wells. Moreover, the CGR decreases with production time. A fixed-pressure, two-stage separation process is suboptimal for this area. Calibrated physics-based models leveraged to an integration platform can significantly improve the facilities performance.

The facilities set up is as follows: the gas produced from a well is fed to a line heater followed by a surface choke. The fluid then enters a gas processing unit (GPU) separator. The separated fluids from each well's GPU in the well pad are processed at common facilities consisting of separation and compression. The processed gas is exported to a sales gas line and the liquids are transported separately.

A fully integrated model has been built for eight wells on a pad. The reservoir and well models were history matched and then integrated with the surface network and facilities (compressor, heater) using network modeling and integration platforms. Various scenarios were run to identify the optimal pressure setting for a given month. The optimization exercise yielded 5-10% additional natural gas Liquids (NGLs) on a pad by increasing the GPU pressures by 100-200 psi. The higher GPU pressures reduced the well choke pressure drop, thereby reducing the heating requirements by 50% as the assurance risks due to hydrate formation and reduced inhibitor injection costs. Finally, the compression energy requirement was reduced via better management of the pressure staging.

The developed integrated models, combined with digital platforms, offer novel and versatile capabilities for efficiently operating an asset to maximize liquids and reduce operational expenditure (OPEX). The deployment of a physical model-based digital oil field will facilitate the validation of these models on a continuous basis. This in turn will allow changes to be made in the field to keep the system optimized as the characteristics of the producing fluids change with time.