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## **Flow Rate Estimation From Wellhead Pressure and Temperature Data**

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### **Abstract**

Flow rate metering has less-than-satisfactory track record in the industry; modern sensors offer solution to this vexing problem. This paper offers two methods for estimating flow rates, predominantly from temperature data to complement rate measurements. One approach consists of modeling the entire wellbore and requires both wellhead pressure and temperature, whereas the other uses transient temperature formulation at a single point in the wellbore to compute the total production rate.

In the entire-wellbore approach, we use a wellbore model handling steady flow of fluids but unsteady-state heat transfer to estimate production rate, given wellhead pressure and temperature. The model rigorously accounts various thermal properties of the fluid and the formation, including Joule-Thompson heating and/or cooling. In the single-point approach, a single point temperature measurement made anywhere in the wellbore, including at the wellhead, is needed to estimate the mass rate at a given timestep. The method entails full transient treatment of the coupled fluid and heat flow problem at hand.

Examples from both gas and oil wells are shown to illustrate the application of the proposed methodology. Good correspondence between the measured and calculated results demonstrates the robustness of the proposed methods. These methods provide important rate information in various settings. For instance, in mature assets they can fill in the information void between tests or replace suspect rate data. Even well-instrumented wells can benefit because the methods can act as a verification tool, particularly in assets where integrated asset models are used to fine-tune rate allocation. In addition, the single-point approach can provide the much needed rate information during pressure-transient tests.

### **Introduction**

Individual well rates enter into a variety of engineering calculations; paradoxically, the industry has struggled to meter this entity with decent accuracy. In fact, accuracy in flow metering has not kept pace with pressure and temperature measurements. Ordinarily, allocation algorithms are used to assign individual well rates from total production, unless a well is instrumented with a flowmeter. The lack of rigor of these allocation routines pose significant challenges during history matching of reservoir performance, particularly those involving rapidly changing events, such as coning or cresting of gas or water. In this context, test separators do not necessarily alleviate the metering issue simply because of inadequate flow time for large distances between a well and the point of separation, coupled with low-test frequency. To compound the matter further, the industry has lacked motivations for accurate metering of nonessential entities, such as water, and to a large extent gas because of its flaring in many field operations. In a case study, Kabir and Young (2002) discussed some of the issues related to gas and water metering in a typical brown-field operation.

To enhance the quality of rate measurements at the individual wells, dedicated metering has evolved over the past two decades. However, direct metering of multiphase fluid flow in a pipe is a difficult proposition because both volume fractions and the individual phase velocities must be ascertained. Accordingly, flowmeters have been developed to handle complete, partial, and no separation of phases. Because gas-volume fraction increases with decreasing pressure, downhole metering at higher pressures can largely mitigate handling of the gas phase. Venturi-type flowmeters, requiring no separation of phases, have gained wide acceptance both in downhole (Webster et al. 2006; Tibold et al. 2000; Brodie et al. 1995) and at surface (Warren et al. 2001, 2003; Retnanto et al. 2001; Pinguet et al. 2006). Venturi-type flowmeter appears to have performed well in a comparative study reported by Busaidi and Bhaskaran (2003). Like the venturi, downhole fiber-optic flowmeters is another nonintrusive device that has undergone considerable field testing (Kragas et al. 2002, 2003). Gas/Liquid Cylindrical Cyclone or GLCC technology (Kouba et al. 2006) separates gas from the liquid phases to facilitate ease of measurement at surface. The liquids are metered on the basis of mass using the Coriolis principle (Liu et al. 1988). Oglesby et al. (2006) reported their field experiences with GLCC while testing high-water-cut wells.