Dr. Prashant Haldipur, MSi Kenny, USA, presents the company’s field experiences with virtual metering technology.

This article presents field experiences with the implementation of virtual well metering technology. The technology is used to obtain well-by-well flowrate estimates using conventional pressure and temperature instrumentation in a wellbore and tree without the need for expensive physical multiphase flow meters. The article focuses on a Virtual Metering System™ (VMS) for a four well subsea development in the North West Shelf (NWS) of Western Australia, which was commissioned in October 2007. The article presents field data comparison and shows that this technology has provided very reliable and accurate flowrate predictions; historical data suggests that monthly reconciliation factors less than 5% can be achieved.

**Introduction**

In recent years, we have seen an increased demand to obtain real-time well-by-well flowrates for both reservoir management purposes and fiscal allocation. One option is to install subsea physical multiphase flowmeters, but this is expensive; also, testing, calibration, and post-installation tuning of these meters is often problematic. Furthermore, for subsea installations, it is generally not economically viable to remove these meters in order to carry out maintenance if needed. A considerably less expensive and easier to maintain proposition is to use software-based solutions to estimate the well flowrates in real-time: either as the primary well metering solution or as a back-up to physical multiphase meters. This technology is known as inferential or virtual metering.
Virtual metering systems use the conventional pressure and temperature instrumentation in the wellbore and tree to estimate the well flowrate. MSi Kenny first deployed VMS in the mid-1990s in the Southern North Sea, and the technology has since matured into a robust high-availability product that can cope with real-life installation issues such as data unavailability, parameter uncertainties, and provide accurate results.\textsuperscript{1, 2, 3} This article presents the deployment of the MSi Kenny Virtuoso/VMS technology in the North West Shelf of Western Australia.

**Description of virtual metering system\textsuperscript{TM}**

VMS estimates the three-phase well flowrates in real-time using existing instrumentation within the wellbore and on the wellhead. The software is based on models that extend from the reservoir to downstream of the wellhead choke. Usually, there is adequate information/instrumentation available to use multiple independent models to estimate the well flowrate. Multiple estimates make predictions more accurate and the technique robust and tolerant to instrumentation failures. Typical measurements used by the system are:

- Downhole pressure and temperature.
- Before choke pressure and temperature.
- After choke pressure and temperature.
- Choke position.
- Master, wing, and shutdown valve status.

**Modelling**

The models used to construct these systems are discussed here. The four building blocks that make up the system are: (i) a near-wellbore reservoir model; (ii) a transient wellbore model; (iii) a choke model; and (iv) a well jumper model. The near-wellbore reservoir model is used to provide the pressure boundary, which in conjunction with the well inflow performance characteristics (IPR/PI) is used to estimate the flowrate across the perforations. The full-stream fluid composition, wellbore profile (vertical depth vs. measured depth), tubing diameter(s) and roughness(es), and the geothermal gradient are used to configure the wellbore model, which predicts transient three-phase flow in the well. The mass-conservation equation, the momentum-balance combined with appropriate closure laws depending on the flow regime, and energy-balance equations are solved to estimate the flowrate in the wellbore. The choke model uses the choke Cv relationship with pressure and temperature measurements across the choke to estimate the flowrate.

Figure 1 shows a typical screen from the VMS application that details all the key information regarding the well. In the bottom panel of the screen, the estimated gas and liquid flowrates from each of the methods are listed along with the actual flowrates measured by the VMS system.

![Figure 1. VMS screen with the various method calculations and well surveillance information.](image1)

![Figure 2. Comparison of gas mass rate predictions before tuning (out-of-the-box) and after tuning VMS.](image2)
with the calculated uncertainties. The system uses real-time calibration programmes that reconcile the total well production estimates, on a daily or weekly basis, with the fiscal metering and then allocate the production back to the wells based on these calculated well flowrate uncertainties. The screen also lets the user turn-off specific models - the turned-off methods are greyed out. On the top of the screen, the user can choose different flash conditions - after-choke condition, before-choke condition, separator condition, or reservoir condition - to display the mass and volume rates. The well flow summary table automatically updates to report the well rates at user-selected flash condition. The VMS system has built-in instrument surveillance to ensure that the measured inputs to the model are of good quality. The Filtered Instrument Values table (Figure 1) summarises the key instrument readings for the well, including valve status/positions. These visuals including quick trends, traffic-light warnings, and colour-coded instrument readings help the operator in quickly locating the source of the error and enable prompt intervention.

**Field example**

Here, we discuss a four well subsea development on the North West Shelf of Western Australia in approximately 130 m water depth. Production started in October 2007 and the VMS system was commissioned by the end of October. The wells are tied back to the platform via a single 24 km pipeline, i.e., the well flows are commingled. Three of the wells are from one reservoir, producing lean gas/condensate with a lower CGR (< 50 bbl/million ft³). The fourth well is from another reservoir, producing rich gas/condensate with a higher CGR (> 100 bbl/million ft³). The wells are high producers with nominal production from each well at over 200 million ft³. Formation water cut is less than 2% during early life. All wellheads are instrumented with dual pressure and dual temperature sensors.

**Commissioning**

Figures 2, 3 and 4 compare the performance of the untuned (out-of-the-box) system during commissioning. The total mass rate predictions were only slightly lower and within 10% of the measured value. After commissioning, the system was tuned based on the latest available as-built data. The key changes made were: (i) the near-wellbore reservoir pressure was updated based on the cableless gauge data; (ii) wellbore profile was updated based on as-built drawings; (iii) the wired downhole gauge locations were updated based on the as-built drawings and the downhole methods were reconfigured to use the wired downhole gauge; (iv) the wellstream composition was updated based on PVT analysis collected during commissioning; (v) the choke Cv profile was adjusted; (vi) the tubing roughness and heat transfer coefficients were modified; and (vii) the well IPR was modified based on the updated information provided by the reservoir engineers. These changes are not time consuming; the system was reconfigured in less than

---

**Figure 3.** Comparison of liquid mass rate predictions before tuning (out-of-the-box) and after tuning VMS.

**Figure 4.** Comparison of total mass rate predictions before tuning (out-of-the-box) and after tuning VMS.
a week. Figures 2, 3 and 4 also depict the performance of the system after it was tuned; it is clear that excellent agreement is achieved between predictions and measurement after tuning.

**Historical performance**

This VMS system was installed in October 2007 and over the past two years, the system has performed well. Since other unmetered platform and subsea wells are commingled with production from the ‘VMS-equipped’ wells before going to the production train metering, an estimate of VMS accuracy is possible only when these ‘VMS-equipped’ wells are aligned to the train by themselves. Figure 5 shows the comparison over such a time window and we can see that the commingled prediction is within 5%.

There is also a Venturi wet gas meter on the riser that measures the total production from these “VMS-equipped” wells. The fidelity of this meter is not of the same calibre as that of the production metering runs and further, it uses information from VMS (gas and liquid density, gas mass fraction, and isentropic exponent) to do its flow calculation. Nevertheless, a comparison between the VMS and the Venturi meter is shown in Figure 6 and we can see that they are in close agreement.

**Conclusion**

Virtual metering systems have been in operation for more than a decade and can now be considered to be a mature technology. Over the years, VMS has developed into a robust technology that can overcome real-life installation issues such as data unavailability, communications problems, data degradation, and system maintainability over the entire field life. These systems combine multiple methods to provide a robust estimate with the lowest overall uncertainty. These uncertainties are used to back-allocate the reconciled production to the wells. These systems are also equipped with smart logic to detect instrument failures and sudden changes in field conditions and provide an early warning to the operator.

These systems can easily be integrated with real-time pipeline simulators to offer a wide range of fit-for-purpose solutions. These range from standard forecasting tools for pipeline flow assurance guidance on issues such as hydrate monitoring, pigging, MEG tracking, cool-downs and warm-ups to complex solutions such as hydrate restriction detection and leak detection. Since these real-time systems are calibrated to the actual field condition, these solutions can provide results with a high degree of accuracy.

**References**