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Intelligent Continual Right-Time Analysis of Field Data as a Service

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Abstract

This paper describes one application of Right-Time analysis of continual field measurements as used in a high-rate HPHT field in the North Sea. Many sensors and devices in the field are available for constant monitoring at the reservoir manager's desk, yet, we are still faced with the challenge of transforming all this raw streaming data into useful information. Data is regularly used to identify anomalies in the classical Field Automation sense. At medium-long term, however, it ought to be used to identify well and reservoir signatures that help in Formation Evaluation, and for reservoir management and planning. This rarely happens because the analysis involved – which includes highly technical disciplines – simply cannot be automated by computer. This makes it vital to be able to streamline these activities and to deliver the associated analysis as a turnkey service to the Field Operator.

Introduction

Measurement, automation and control in general, and within the upstream oil industry in particular, has seen an explosion in activity over the last two decades. In virtually every field of engineering, there has been a concerted effort to exploit new technology to maximize the efficiency of a wide variety of processes.

Within the oil and gas industry, this process of improved measurement and automation was led by the downstream sector, following the trend in Process Engineering in general. Shortly thereafter, the midstream gathering and transportation pipeline sector followed the same direction, adapting systems utilized in other energy-related transportation industries, notably electric power. For at least a decade now, initiatives in the upstream exploration and production sector typically termed “Intelligent” or “Smart” Fields, “e-Fields” or “Fields of the Future” have also begun to communicate field information directly to the reservoir manager’s desk. This topic, also widely referred to as “Digital Energy”, is widely discussed in the literature, but a good applications-oriented review is given by Chorneyko (2006).

The Field of the Future concept really covers two broad issues:

- Classical measurement, automation and control similar to any Process Industry. Wells, downhole equipment, meters and sensors, separators, pipelines and other facilities are all essentially components of a standard production process chain. As such, they are best managed using modern automated systems.
- Advanced Reservoir Management. Since the reservoir itself is a highly important but unconventional component of the production chain, it requires special attention. Most of the measurements taken are indirect (downhole pressure sensors, surface flow rates, water and gas cut, etc.) and the controls are also indirect (choke settings, pump rates, water and gas injection rates).

These two issues are also best understood in terms of time-frame and granularity. Saputelli et al. (2003) describe this well in Figure 1. At short periods, data is already widely used to identify anomalies and provide alarms in the classical Field Automation sense. At millisecond-to-second resolution, most measurement and control is done directly by electronics, within automated controllers and DCS systems. The applications are typically regulatory control and emergency management.

At the minutes-to-hours level, more centralized and supervisory control is possible with some human intervention. Here, the applications are more proactive and begin to address efficiency, but they are still largely accomplished in software. Over days and months, the applications are becoming more strategic. Real-time data is beginning to be used in optimization, scheduling and planning. Specialized software has been developed that allows at least a partial automation of these tasks on the basis of field data, as well.

Advanced Reservoir Management only becomes possible over months and years and it involves a completely different set of techniques, expertise, people and objectives. We also note these other major differences along the Saputelli et al (2003) timeline:

- While short-term automation solutions are relatively widespread, all uses of field information get gradually rarer as the timeline increases. For example, wellhead safety systems that trip within milliseconds, or automatic Fire & Gas systems, are extremely common. By contrast, programs that systematically and strategically store and analyze all field data on an annual basis for decision-making purposes are extremely rare.
- The application of analysis to the data becomes more and more specialized and less suitable to automation as the timeline, and therefore volume and complexity, increases. PID control is carried out entirely via algorithms and even medium-term optimization can be performed by computer. Long-term reservoir modeling, however, requires a skilled engineer even if he is supported by software tools.
- There is a significant people issue that divides each of the time regimes from the other. Short-term field control is the domain of Operations. Medium-term optimization is Production Engineering. Longer-term strategy is the responsibility of the Asset Manager and Reservoir. For each of these stakeholders, their time horizon alone defines their Field of the Future and we have yet to define the “owner” of the entire lifecycle.

Another serious people issue is that the skilled engineers that can deliver this analysis are becoming ever busier and in short supply. This makes it vital to be able to streamline these activities and to be able to deliver the associated analysis as a turnkey service to the Field Operator.

However, the biggest factor that differentiates each time horizon from the others is potential upside value to the Asset. Of course a safety system can avoid extremely costly losses to an Asset, but this is pure downside mitigation. However, the real upside potential is in the leveraging of field data to increase recoverable reserves. In a recent study by Shell, Darley (2003) reports their assessment of the potential relative value contained in a set of applications for real time data. This assessment in Table 1 shows that less than half of potential locked-in value can be achieved through traditional automation and control applications, and fully 53% of the value of the Field of the Future lies in its increased Ultimate Recovery. Darley (2003) also reports an expectation of 25% to 35% improved well lifecycle value due to the application of long-term utilization of real-time information.

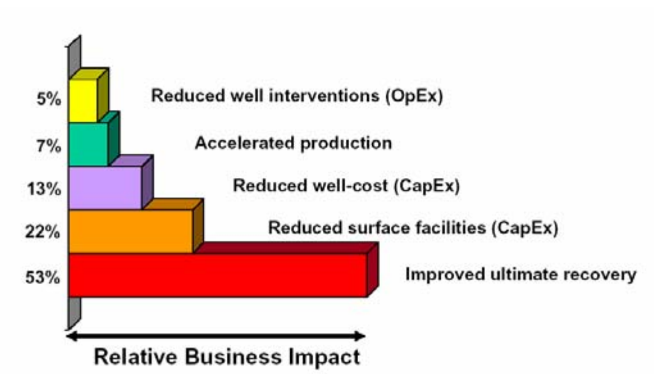

Table 1 – Shell Smart Well Studies, Relative business impact

Chorneyko (2006) also makes the point that it is not only the timeframe of the data, but also its granularity or resolution that is important to the analysis and optimization being performed. Figure 2, for example, shows how as a rule most long-term strategic reservoir surveillance activities rely on lower latency information. There are, however, certain studies – and pressure transient analysis is an excellent example – where high-resolution data is required even many years later. The data management strategy, and all other systems involved with the analysis, must therefore be designed to take into account the need for potentially long-term storage and administration of massive field readings and information. In general, all systems and procedures that are adopted should bear in mind the ultimate application of the data, so that the correct values, data types, precision and resolution are stored for processing.

In this paper, we aim to emphasize two main points, which we feel are overlooked too often by specialists in this area. First is the essential requirement to design and to operate Smart Field initiatives with the ultimate aim of analyzing the data methodically and over extended periods of time in order to maximize Asset Value. It is not enough simply to automate a field. It must be designed so that systems are in place to gather, manage and analyze data and information systematically and sustainably over the long term, using specific fit-for-purpose techniques.

The second main theme is that this appropriately selected data, gathered in "right" time, can only be processed in part by a computer. A great deal of the truly high-value analysis can only be performed by the petroleum engineer. In today's business climate, these skilled engineers are becoming ever more in short supply. This makes it vital to be able to streamline all processes and to be able to deliver the associated analysis as a turnkey service, probably from a third party supplier.

Technology

Reflecting our comments in the introduction, it is useful to think of the overall technology set used in Intelligent Fields in two very distinct halves:

- Technology that is common to all Process Industries
- Specific, oil and gas exploration and production technology

In the first category, there is a distinct advantage in seeking solutions that are common to a large applications and user base and are as standardized as possible. Relatively little attention, unfortunately, has been devoted to the elements that are specific to oil and gas exploration and production.

Figure 3 illustrates the whole technology "stack" that is required to get data and raw information to the engineer's desk, in "Right" time – in other words, at the resolution and the latency necessary to provide the analysis used to help improve Ultimate Recovery. In sequence, it includes:

- Field devices making measurements and providing local automation. Some of these are standard across many industries (wellhead meters, chokes and valves, for example) while some are very specialized (downhole pressure sensors, multiphase flow meters, etc.) However, nearly all of them are accessible using extremely standardized protocols.
- Field networks and communications. Requirements here are usually common to many industries, and benefit strongly from standardization.
- "Middleware" refers to the entire data management, interfacing, and workflow / process issue. By its nature, this layer is very specific to the petroleum industry and to the ultimate stated application for the data. However, the Information Technology tools that are utilized for this task are cross-industry and standardized.
- Applications software is also very specific to the kind of analysis being performed. Sometimes, the software needs to be modified by the developer to accommodate direct field data input, and sometimes this is handled in the Middleware layer.
- Finally, only an experienced petroleum engineer can really understand the value, applicability, analysis and significance of studies of the field data and information.

Thus, as we reach the outer layers of this stack the processes become more and more specialized, and require ever more specific petroleum expertise, from skilled engineers who are becoming ever busier and in short supply.

Applications

There are almost as many opportunities for exploiting good quality, intelligently gathered data from the field as the petroleum engineer's skill, imagination and available time permits.

Figure 4 gives a very brief overview, illustrating some of the primary uses currently being explored. It follows the same timeframe structure as the earlier figures, overlaying the kind of analysis that can be done over each time horizon.

As we remarked earlier, many of the applications at short timeframes are common to any process engineering system. The diagram also identifies medium to long term analysis of Variance, Anomalies and Trends. This refers to Data Mining, where correlations and trending between different inputs to the system (water or gas injected, lifting, and so on) affects outputs (production, water rates, pressures, etc.) This specialized statistical analysis provides a level of confidence in the impact a given field process variable has on any other. Note how this technique need not assume anything at all beforehand about the reservoir itself – it simply looks at the data – and it can be used for a variety of purposes:

- Detecting anomalies – where the normal trend and correlation is broken;
- Aiding reservoir description – by identifying connected and disconnected wells and regions;
- Trending and prediction; and
- Early warning of failure.

Neural networks and other AI techniques are often used for this purpose in addition to statistics.

For the all other applications, we cite a number of specific field examples as follows:

Mature Fields – Pump-off Control
For many mature fields, facilities optimization is the primary driver for Asset Value.

Ormerod et al. (2006) report a very complete pilot of an intelligent mature field in the San Joaquin Valley of California. The project automated and telemetered a large number of Pump-off Controllers (POC's) throughout San Joaquin Valley. Overall 15,000 active wells were equipped, each with an average rate of 13 BOPD, for a total production of 200,000 BOPD.

The objective was operational – to reduce downtime and maintenance costs on the pumps. Thus, the stated objective was, to use the categories in Table 1, "Reduced Well Costs". However, the authors quote the average repair cost as $6,000 but the average deferred production expense during a repair as $3,000. Therefore, the issue really remained, at least for half "Accelerated Production" as well.

The system includes "LOWIS" that is a good example of the "Middleware" in Figure 3, which integrates analysis with economics, well tests, work planning, ticketing, etc.

The analysis workflow is well designed around the engineers who perform the analysis and make decisions:

- Each surveillance engineer is allocated a group of wells to monitor closely, while also having access to the overall performance database
- The engineer monitors his wells for efficiency, and for any performance degradation. He sets POC setpoints; and issues work orders for preventive maintenance.
- The overall performance history is trended, graphed and data mined. This provides all engineers with performance metrics, guidelines and targets.

The value of this project is manifest. One-twelfth of the field is under this workflow, with demonstrated annual savings of at least $0.5MM/yr. This extrapolates to potential annual savings field-wide of $6MM/yr. Extrapolating, the hardware cost for a complete deployment would be $9MM meaning an immediate payout within only 18 months.

Even these economics are conservative, reflecting only pure OPEX savings, since the real value of the system lies in the potential for improved production control and the ability to manage the reservoir itself. The authors do not comment on the impact on Ultimate Recovery, but in a waterflood situation this could amount to over twice this sum again.

So why isn't everyone deploying similar systems everywhere, and for that matter why isn't Chevron itself expanding the project to the rest of the field? The major issue is not really budget, hardware, technology or even process – it is skilled engineering analysis man-time. A complete roll-out, however thoroughly automated, would require a large number of petroleum engineers. This confirms the second main theme of this paper – that there is no escaping the input from skilled engineers at the highest level of the technology stack and that it is difficult even for the super-majors to provide these resources in-house.

High-Rate Offshore Wells – Completion and Reserves Monitoring
The idea of utilizing permanently installed downhole pressure gauges to perform a "virtual" continual pressure transient analysis is almost becoming standard practice. For example, Coludrovich et al (2004) report on the use of real-time pressure measurements in BHP Billiton's Boris Field in the Deepwater Gulf of Mexico.

Critical parameters of high-value wells include their local permeability and skin. With high-value assets the reserves, both in place and recoverable, as indicated by reservoir drainage area, are equally critical. All these values are accessible from flowing reservoir performance measurements, typically by analyzing pressure transients in the well. Coludrovich et al (2004) study all the shut-ins that occur as a matter of course during the operation of the well using standard Pressure Transient Analysis methods.

The technique is used routinely to:

- Monitor completion skin;
- Provide current reserves; and
- Match performance against plan

A dramatically improved ability to track (and deliver) actual production against plan is reported.

Once again, this activity is labor-intensive and requires experienced staff. Depending on the complexity of the well and its associated reservoir, it can be a full-time job for a reservoir engineer to monitor just one of these wells. A small, but high-value, asset like Boris with two wells could therefore potentially fully occupy at least one valuable reservoir engineering expert.

High-Value Wells – Multiphase Rate Monitoring
Webster et al. (2006) report on the use of sophisticated downhole multiphase rate monitoring which requires the application of both specialized metering devices and complex analytical techniques.

Applications include:

- Accurate flow allocation between formations where the well is completed
- Flow Assurance – monitoring liquids in the tieback
- Providing a continual "virtual" Production Logging capability
- Calibrating a reservoir model for field management

BP concedes that the flow meters are in fact still not being used extensively for field management, concentrating instead on flow allocation and well surveillance (logging). Nevertheless, the ability to have what amounts to a continual downhole profile of rate with depth is of extreme value.

This is an example of a situation where the analysis is already supplied turnkey by Schlumberger-Doll Research to the operator BP. The ability to see the results of the analysis as listed above – provided methodically and expertly without interruption – is just as valuable as the instrumentation itself.

High-Rate Gas Wells – Well, Reservoir and Completion Monitoring
To give an idea of the complexity of the overall workflow involved in a thorough well surveillance, we present the example of a high-rate, high-value offshore gas well which is equipped with downhole pressure sensors. It is not, however, equipped with accurate flow metering and so well rates have to be estimated by allocation.

This is a useful example in part because it shows how utilizing a complete history of downhole pressures compensates to a degree for the lack of accurate rate data, and also provides estimates of reservoir flow allocation that would normally require the expensive downhole multiphase meters described above. Minute-by-minute readings are therefore valuable even several months after they are taken, so long as they are available to be included in the analysis.

Data preparation

The first step in the analysis is data preparation as illustrated in Figure 5. This is a three-step process:

- Obvious noise / null value removal
- Outlier removal
- Data reduction / compression

The initial dataset, corresponding to about six month's data, contains perhaps one million data points. Noise and data dropouts can usually be identified algorithmically, so the first step can fortunately be accomplished automatically. Outliers can also be identified via algorithms, but they are only perhaps 50-70% successful in real-life datasets. The remainder needs to be removed by an engineer. The final data compression is fortunately entirely programmed. It does require care, however, since it introduces another level of data smoothing which may mask genuine physical effects.

Referring to Figure 5, the initial raw field data is charted on the upper left. Extensive obvious poor data is evident in early time (it appears as solid blue, since so many null values are plotted). More outliers are still evident in middle time, and they are visibly less predictable in their value and frequency. Later, more recent data is of much better quality.

Transient identification

In a typical flowing well, there is usually no shortage of pressure transients that are candidates for analysis. It is worth noting that a pressure transient analysis can be performed on any period following an abrupt rate (or pressure) change, during which the rate (or pressure) stays constant – even if it is not a complete hard shut-in or drawdown. In the dataset shown in Figure 5, there are between two and five such periods per month, and Coludrovich et al (2004) report similar statistics. In fact, there are at least four reasonably long hard shut-ins due to process trips over a six-month period.

Not all these periods are suitable for analysis, however. They need to be screened for:

- Sufficient length to allow at least pseudo-steady state flow to appear
- Sufficient consistent data quality over the entire duration: very often, the downhole sensor "sticks" and does not provide streaming data during the entire event.

In addition, given only allocated rates, certain adjustments of the precise time at which the step change in rate corresponding to the buildup needs to be made. Although this adjustment can be automated, the only reliable method seems to be by inspection. Of course, the more the rate change adjustment needs to be, the worse the likely quality of the analysis.

Pressure Transient Analysis

The first PTA performed on the well differs enormously in effort and scope from the routine follow-up PTA's that follow.

This particular well penetrates two distinct reservoirs, and the gas is commingled in the wellbore. A particular type-curve reservoir model is available for this situation, but it has a large number of free parameters each of which are estimated by matching individual features of the pressure curve and its derivative. In addition, the well is close to two faults, and so a late-time channel flow model also has to be fitted. Several potential matches are of course possible, so the range of possible parameters has to be narrowed by comparison with evidence from other geological and production data.
With this model, the following parameters can be estimated during each transient:

- Wellbore storage coefficient and equivalent initial reservoir pressure at datum
- Layer 1 – permeability-thickness, porosity, and completion skin
- Layer 2 – permeability-thickness, porosity, and completion skin

We remark that obtaining a good initial reservoir model is time-consuming and can take up to several weeks especially if it is complex.

Subsequent PTA periods can then be performed using the deconvolution technique, described by Gringarten (2006) and elsewhere. An example is shown in Figure 6. Deconvolution takes a conventional PTA for a transient lasting about 32 hours, and extends it to nearly 4,000 hours by utilizing the entire rate / pressure history. Of course, this relies on nearly six months of history being available on demand and so careful data management and archival is essential to perform this analysis.

We are thus able to utilize modern techniques to use quite short transients to probe very deep into the reservoir. Indeed, the longer we maintain a continual, methodical program of data collection and analysis the further into the reservoir we can investigate.

Results

The true value of this analysis is not merely the initial values of the model parameters listed above, but how they evolve with time. It is inevitable, for example, that skin will increase over time, so by continual surveillance it is possible to have a new snapshot of its value with every analyzable transient. Any serious completion damage, or an increase in rate of damage, is therefore immediately evident.

With up-to-date permeability-thickness, porosity, and completion skin, a highly accurate forecast of production and therefore remaining reserves is possible. A revision of reserves is therefore possible with every analysis as well. The ability of the Production team to track and meet the production plan is therefore dramatically improved.

In the particular case of this commingled two-reservoir well, it is also evident how the total gas flow rate is divided between the reservoirs. Figure 7 shows how, over time, this allocation changes dynamically. Early on, the "Green" reservoir is responsible for about 80% of production, while more recently it shares it almost evenly with the "Yellow". This direct layer-rate information is otherwise only available from expensive production logging tools or downhole flow meters.

Effort

Once again, this analysis is intensive of technically advanced engineering manpower. Although the results are invaluable in terms of well / completion health monitoring and reserves / production forecasting, they do require an experienced analyst. It should be noted, however, that once the initial assessment of the reservoir is performed, additional individual transient analysis is quite rapid.

Towards a Packaged Service

As with most reservoir-related studies, we must address the issue of relatively high-cost and rare engineering resources, and the major factors are:

- Data transmission from the field of relevant analysis-grade data;
- Interfaces to software and specialized reporting displays for information screening;
- Systematic analysis workflows that include specialized petroleum software packages; and
- Web reporting mechanisms for the Asset Management Team.

We are aiming for a situation where we require no effort or wasted time from the Field Reservoir or Production Engineer – rather, to allow them to review results carefully and to focus on specific important items.

The kind of analysis that we have been discussing – if it has been designed and prepared correctly – is in fact considerably more efficient than more conventional "off-line" studies that are executed individually from static data and provide conventional reports. It is widely remarked that a typical petroleum engineering study is about 70% data collection and reporting. The first and final points listed above suggest how this inefficiency is eliminated in a modern environment. If the correct system – illustrated in Figure 3 – is in place, data collection should simply be a matter of accessing centralized real-time historian systems. Similarly, if the results of the analysis can be reported regularly and systematically using Intranet-based systems, all the effort of technical publication can be minimized.

Therefore, although a theme of this paper is that the Digital Oilfield still requires experienced and sophisticated technical analysis, it is absolutely true that its underlying Information Technology makes it orders of magnitude more efficient than conventional studies.

Conclusions

Although many of the components of the Intelligent Oilfield have been well thought-out, and many of the individual technology components for its implementation have been thoroughly developed, we still need to give thought to its main potential benefit – increasing the field's Ultimate Recovery.

This can only be achieved if the numerous possible issues – which depend on the field, its technical description and lifecycle – are analyzed carefully from a reservoir and production engineering standpoint. We have illustrated a number of examples, including lifting efficiency, completion monitoring, reserves monitoring, and flow allocation to name a few. Each of these initiatives has a demonstrable and significant benefit to Asset Value.

However, they all involve a significant component that cannot be performed automatically by electronics or the computer – the expertise of the reservoir engineer. We therefore argue that this part of the Digital Oilfield needs careful planning and design, including a workflow designed to minimize expert involvement. Apart from the ability to streamline these activities and to be able to deliver the associated analysis as a turnkey service to the Field Operator, it may be that the delivery of this key reservoir knowledge, given the current staff structure of the industry, will only be practical using a third-party service provider approach.

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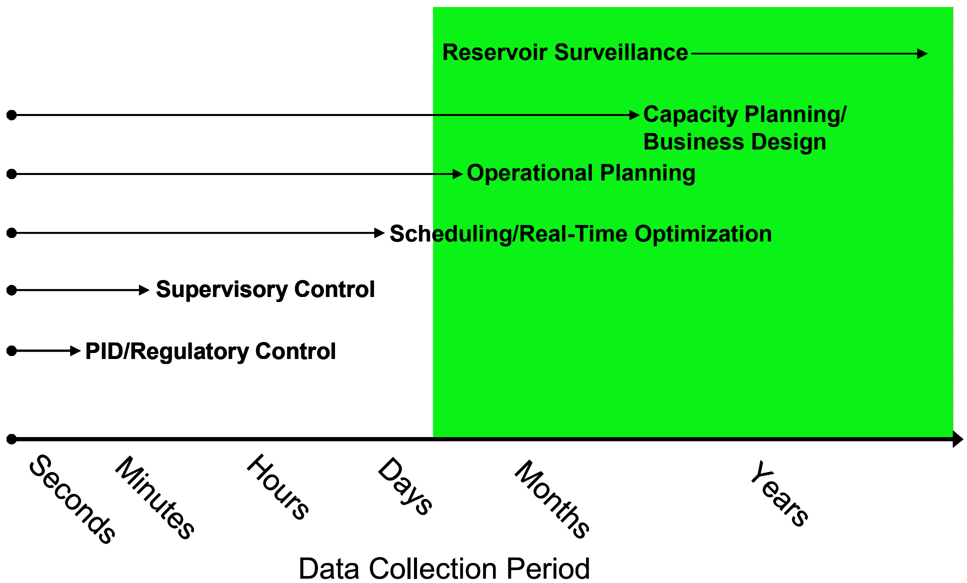

Figure 1 – Application of real-time data by duration and granularity (Saputelli, 2003)

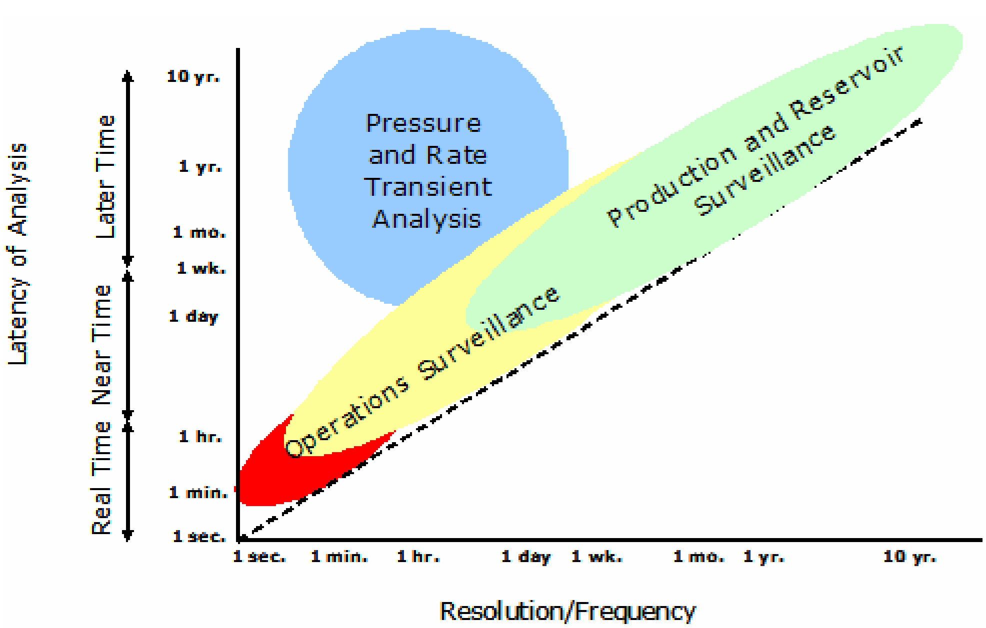

Figure 2 – Applicability of data to applications; Right-Time Data (Chorneyko, 2006)

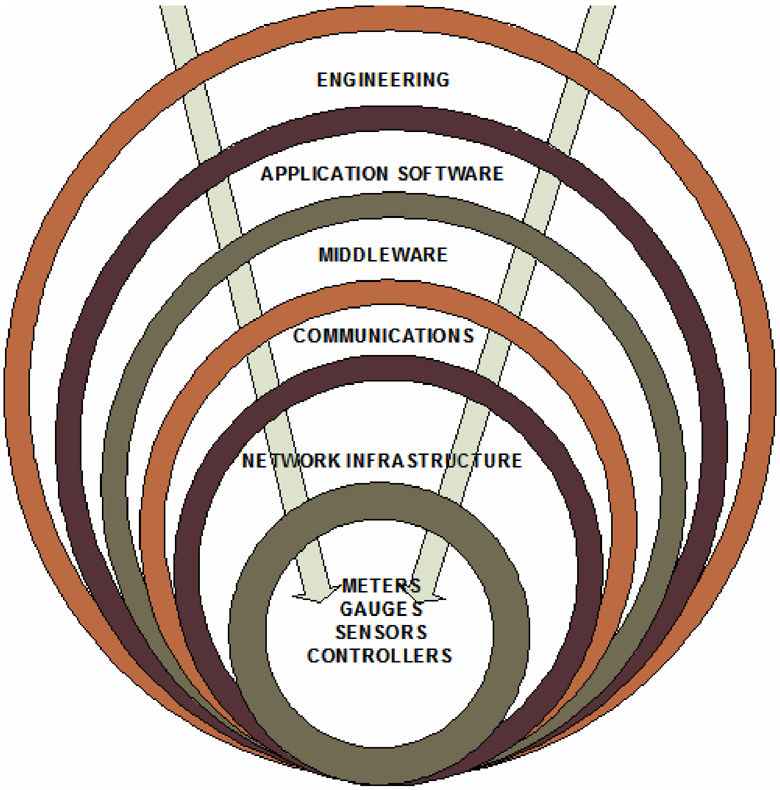

Figure 3 – The overall technology “stack”

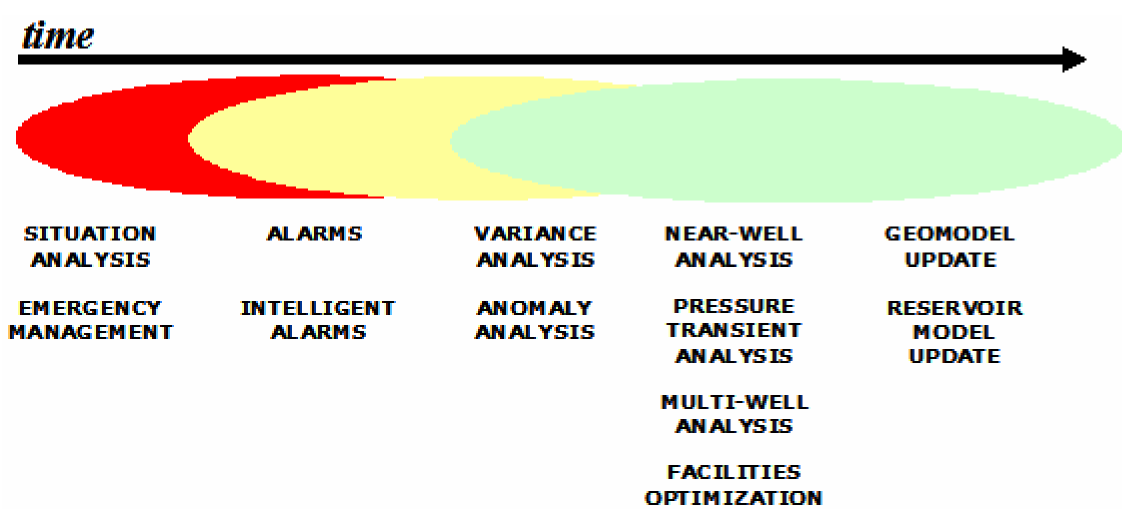

Figure 4 – Applicable technologies

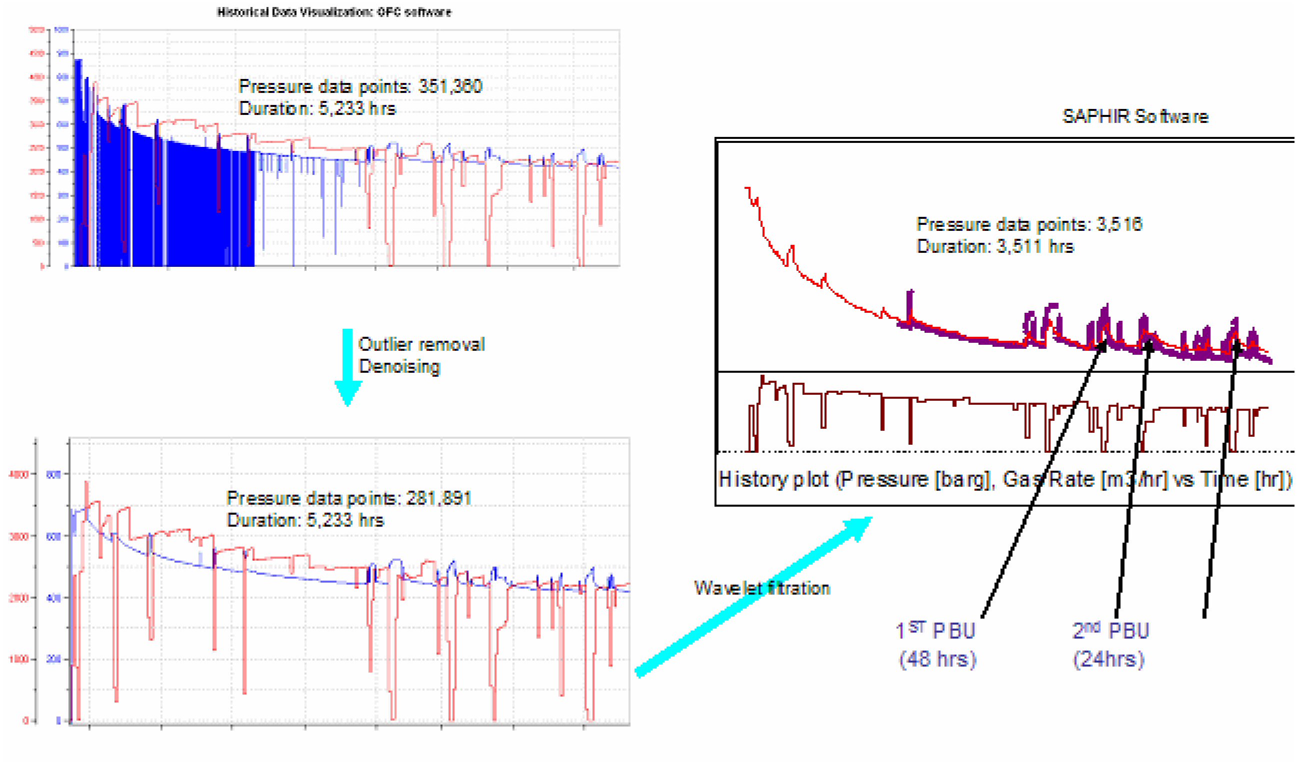

Figure 5 – Data preparation in pressure surveillance

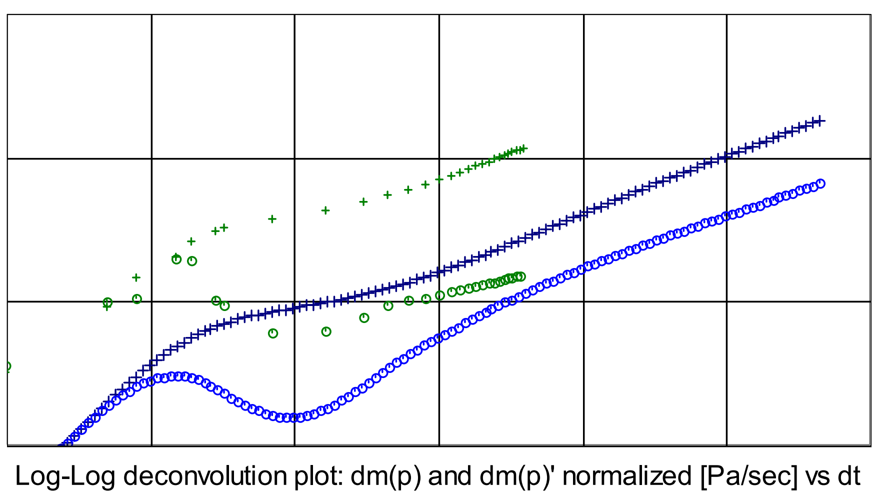

Figure 6 – Deconvolution takes a conventional PTA lasting about 32 hours, and extends it to nearly 4,000 hours by utilizing the entire rate / pressure history.

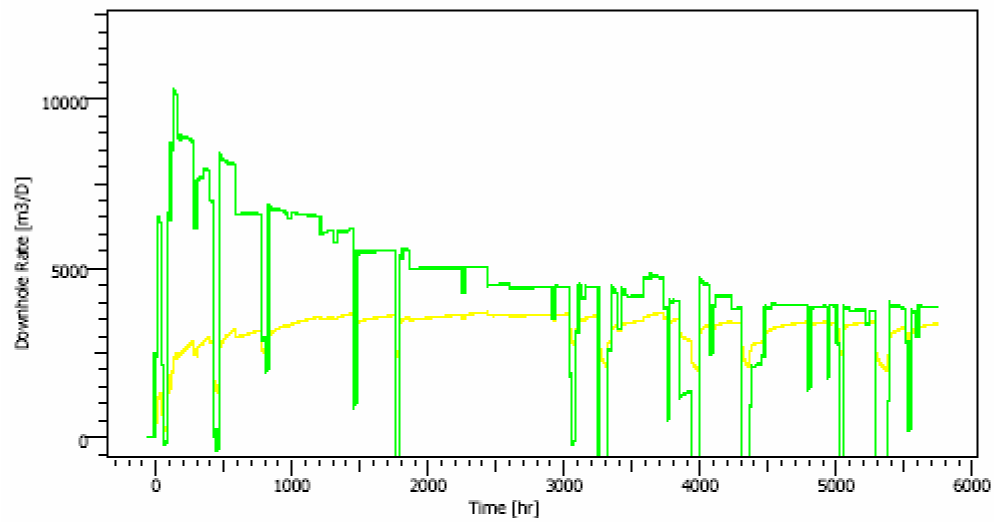

Figure 7 – Downhole layer rates from PTA