Summary
This paper illustrates how practical application of surveillance and monitoring principles is a key to understanding reservoir performance and identifying opportunities that will improve ultimate oil recovery. Implementation of various principles recommended by industry experts is presented using examples from fields currently in production.

Practices in processing valuable information and analyzing data from different perspectives are presented in a methodical way on the following bases: field, block, pattern, and wells. A novel diagnostic plot is presented to assess well performance and identify problem wells for the field.

Results from the application of these practices in a pilot area are shared, indicating that the nominal decline rate improved from 33 to 18% per year without any infill drilling. The change in the decline rate is attributed primarily to effective waterflood management with a methodical approach, employing an integrated multifunctional team.

Although the suggested techniques can be applied to any oil field undergoing a waterflood, they are of great value to mature waterfloods that involve significant production history. In these cases, prioritization is a key aspect to maintain focus on the opportunities that will add the most value during the final period of the depletion cycle. Case studies illustrating the best surveillance practices are discussed.

Introduction
Surveillance and monitoring techniques were first discussed in SPE literature in the early 1960s (Kunkel and Bagley 1965). Since then, several highly recognized authors have published related materials (Thakur 1991; Thakur and Satter 1998; Talash 1988; Gulick and McCain 1998; Baker 1997, 1998; SPE Reprint 2003). Industry experts recommend the following valuable principles:

- The key ingredients of any surveillance program are planning and accurate data collection.
- To understand reservoir flows and reduce nonuniqueness in interpretations, it is crucial to implement a multilevel surveillance effort.
- A single technique in isolation is not generally indicative because different parameters can cause similar plot signatures.
- Controlled waterflooding through the use of pattern balancing requires time and technical efforts—engineering and geological—during the life of the project.
- Valuable insights into the performance of the waterflood can be gained from individual-well plots such as Hall plots.
- Surveillance techniques should always be a precursor to in-depth studies, including numerical simulation.

A process to consistently evaluate the performance of a reservoir—from field to block to pattern to well level—is discussed with the help of real-life examples. Type plots and maps are used to identify opportunities and promote team discussions to effectively manage a reservoir undergoing waterflood. Production history and basic reservoir characterization serve as primary input variables for the recommended analysis.

Table 1 describes the main characteristics of the fields presented as examples.

The first example is from El Trapial field in Argentina. This sandstone reservoir is located onshore, with a primary-drive mechanism of solution-gas drive. The average permeability and porosity are 75 md and 17%, respectively. The field was discovered in 1984, and water injection started in 1993.

The second example corresponds to the Bangko field located in Indonesia. This sandstone reservoir is located offshore, with aquifer support. The average permeability and porosity are 530 md and 25%, respectively. The field was discovered in 1970, and water injection started in 1992.

The third example corresponds to the Meren field located in Nigeria. This sandstone reservoir is located offshore, with a mixed-primary-drive mechanism, including aquifer support and gas-cap expansion. The average permeability and porosity are 1,000 md and 27%, respectively. The field was discovered in 1965, and water injection started in 1984.

A Multilevel Approach
After reviewing many waterflood case studies, one of the key lessons learned is to use a methodical approach to understand where the opportunities exist, thus preventing the implementation of biased action plans or hastily-made judgments. This is especially important in the current environment, where optimization of human and capital resources is a critical issue.

The proposed procedure goes from a large scale to the detailed, as follows.

Field Level. When looking at a field under waterflood, the first intent should be to determine the overall health of the asset. The following are the key aspects to investigate:

1. What is the primary-drive mechanism or mix of mechanisms?
2. What is the current recovery factor, and how many pore volumes of water have been injected?
3. How is the static reservoir pressure behaving through time?
4. What are the monthly and cumulative voidage-replacement ratios (VRRs)?
5. How is the total fluid production behaving (i.e., is it increasing, flat, or decreasing)?
6. How is the gas/oil ratio (GOR) performing?
7. What are the water-production and water/oil-ratio trends?
8. What is the water-injection rate, and how does it compare to the total reservoir voidage in reservoir barrels?
9. How much excess capacity is available for production and injection? Will field improvement be restricted by limitations of current facilities?
10. How do the productivity and injectivity per well compare?
11. Is injection greater than or less than the fracturing pressure? Does the fracturing pressure change from one part of the field to another? Does it change as a function of the reservoir pressure in a given part of the field?

VRR. VRR through time will give an idea of whether enough water is being injected and is available in the field. Both monthly and cumulative values should be monitored. When monthly VRR is greater than 1.0 unity and reservoir pressure is not increasing, out-of-zone injection loss from the target zone or severe thiefing is suspected. When monthly VRR is less than 1.0 unity and reservoir pressure is not decreasing, influx of fluids is suspected (e.g., aquifer influx into the control area). Plotting the oil rate (log scale) vs. time along with the VRR vs. time helps one understand the relationship between these two variables.
**Fig. 1** shows El Trapial field, where a direct relationship between VRR and oil-production rate is observed. Oil rate declines when VRR drops below 100%, and it improves when VRR is close to or greater than 100%. It is important to mention that no aquifer support exists in this field.

The second example, shown in **Fig. 2**, corresponds to Bangko field, where aquifer support does exist. It shows that oil rate is not as dependent on VRR as in the first example.

The last example, shown in **Fig. 3**, corresponds to Meren field, where some aquifer support exists.

**Mapping.** Time-lapse maps of GOR, water cut ($W_{cut}$), and dynamic and static pressures are easy to obtain and are extremely useful. Once these maps are prepared, it is important to spend a reasonable amount of time looking for the following characteristics:

- Areas with low $W_{cut}$ (<70%), producing GOR above dissolved-gas/oil ratio ($R_s$), and low static pressures should be assigned a high priority. Solutions to these cases include incrementally increasing the injection rates, drilling new injectors, or converting producers to injectors.
- Areas with high $W_{cut}$ (>95%), GOR similar to $R_s$, and high well fluid dynamic levels should be reviewed for pumping off and, if necessary, reducing the water injection, especially if water is a scarce resource.
Examination of a dynamic bottomhole-flowing-pressure map will indicate if producers are being pumped off efficiently. It is important to keep the levels down to allow maximum pressure gradient and, therefore, maximum flow between injectors and producers. Additionally, a lower dynamic pressure minimizes cross-flow effects between layers.

In calculating theoretical water injection, flood-front maps will aid in visualizing which areas are mature and which are in need of more water-injection points. Because there are many assumptions regarding fluid flow when calculating the flood front (e.g., the existence of good cement behind pipe), this map should be taken into consideration on a qualitative basis only.

Figs. 4 through 7 illustrate maps of El Trapial field for a given date. After a detailed evaluation of these, one concludes that the waterflood has different levels of maturity. The south is more mature, with high \( W_{cut} \), GOR values close to \( R_s \), and static pressure near original values. At the same time, the north area shows low \( W_{cut} \), GOR greater than \( R_s \), and lower static pressures, suggesting an area with improvement opportunities. Infill drilling and conversions could be recommended after looking at the next levels of evaluation.

**Plotting the Total Liquid Production.** Examination of the total-liquid-production trend through time can give insights to the following:

1. Is the total liquid production flat? Is this because of facilities constraints?
2. Is the total liquid production increasing? If so, how much of this is owing to new drills and how much is resulting from base production optimization?
3. Is there a direct relationship between VRR and liquid production?  

Fig. 8 shows Bangko field data where maximum facility capacity has been reached at a total liquid rate of 550,000 B/D. Waterflood optimization under this condition is limited; thus, upgrading the facilities is currently under study.

Fig. 9 shows Meren field data. Notice that VRR has been above 100% for the last 15 years with an increasing total liquid production. This has resulted in stable oil rates as seen in Fig. 3.
Recovery-factor (RF) vs. PVI plots and \( W_{\text{cut}} \) vs. PVI plots are useful in understanding the drive mechanism and the maturity of an asset. This is a simple exercise and a useful benchmarking metric.

Figs. 10 and 11, respectively, show these plots for the three fields presented. Fig. 10 suggests that Bangko field has some aquifer support as implied by the RF value of 22% before water injection. The field office has confirmed this point, based on the history of pressure support. Fig. 10 also shows an RF for Meren field of approximately 20% before the initiation of water injection. This estimate of RF is the result of the gas cap expansion and some aquifer support in the flanks of the field.

Fig. 11 shows that the \( W_{\text{cut}} \) for Bangko field has been approximately 80% from the beginning, a typical characteristic of aquifer supported fields. By contrast, El Trapial field, which does not have aquifer support, required approximately 0.4 PVI to reach the same \( W_{\text{cut}} \) level.

Validating the Pattern Configuration. A good exercise to perform at this level is to calculate the average total fluid production and injection rate per well at reservoir conditions. After doing so, the I/P ratio is calculated. This value should be close to the one given by the pattern injection selected for the field. As a reminder, a five-spot pattern gives a 1:1 I/P ratio, making it necessary to have one injector for each producer. If the I/P ratio is close to 2:1, an inverted seven-spot pattern will be optimal, and a 3:1 I/P ratio will be suitable for an inverted nine-spot pattern (Thakur and Satter 1998).

Table 1 shows the I/P ratios for the three given examples. The I/P ratio is approximately 2:1 for El Trapial; therefore, an inverted seven-spot pattern was chosen for the field. Had the decision been made to develop using a five-spot pattern, the number of injector wells would have been much higher and unnecessary capital expenditures would have occurred.

In the cases of Bangko and Meren fields, the ratios were between 4 and 7, indicating a much higher value of injection relative to production rates. These two cases had peripheral waterfloods with average permeabilities in the range of 0.5 to 10 darcies, higher reservoir continuity and conductivity, and some aquifer support.

The “ABC” Plot. When looking at a field with hundreds of wells, identifying the performance of all wells can be overwhelming. Additionally, well review meetings are usually time consuming and difficult to keep focused. A different approach has been taken by using a plot called the “After-Before-Compare” (ABC) plot. This plot uses well-test production data from two distinct dates and compares oil and water rate between those dates. The same dates are used for all the wells.

In the x-axis, the ratio of current water rate to previous water rate is plotted. In the y-axis, the ratio of current oil rate to previous oil rate is plotted. Each point in the chart represents a single well in which several behaviors can be quickly identified:

- **Wells without change.** These are wells that fall within the (1, 1) coordinate point area. It is not necessary to spend time on these wells as long as they have been tested properly and frequently throughout the selected period.

![High Pressure](image1)

**Fig. 6—**El Trapial field static-reservoir-pressure map showing low values in the north of the field and higher values in the south of the field.

![Low GOR](image2)

**Fig. 5—**El Trapial field GOR map showing low GORs in the southeast of the field and higher than \( R_s \) values in the northwest of the field.

![High W\text{cut}](image3)

**Fig. 4—**El Trapial field \( W_{\text{cut}} \) map showing contrasting \( W_{\text{cut}} \) High cuts in the south of the field and low cuts in the north.

![Flood-front Bubble](image4)

**Fig. 7—**El Trapial field flood-front bubble map showing good injection in the south and opportunities to inject more water in the north, as depicted by the size of the 2D bubbles.
• **Total-liquid-rate increase.** These are the wells that responded to the water injection. They fall on the 45°-slope line and above the (1, 1) coordinate point.

• **Total-liquid-rate decrease.** These are problem wells. They fall on the 45° slope line and below the (1, 1) coordinate point. Team discussions should focus on root causes. The first intent should be to differentiate if the cause is a result of artificial-lift efficiency or reservoir conditions.

• **W_cut increase.** These are the wells that fall on the lower right part of the 45°-slope line. This is the expected behavior of wells in a waterflood asset; however, special attention should be given to wells falling outside the overall trend. Channeling may be causing a higher than usual W_cut behavior.

• **W_cut decrease.** These are the wells that fall on the upper left part of the 45° slope line. This area of the chart will be unpopulated most of the time. We have learned that new wells may fall in this area when the initial well test shows high W_cut because of completion fluids that are still being produced.

Fig. 12 shows the El Trapial field ABC plot between April 2003 and July 2003.

A 3-month period has been used for this field. We have learned that using a shorter period did not show any significant changes for several wells (i.e., if there is a lack of new well-test data). On the other hand, choosing longer periods could create difficulties when trying to identify root causes for changes, especially if the field is under a large amount of development activity such as workovers, infill drilling, and injection-rate changes. Therefore, each field will have an optimum period for analysis depending on well-test frequency and field activity.

Note that the same plot can be used to assess injector-well performance if wellhead pressure and injection rate are plotted. This will allow the users to monitor injectivity trends at a field level.

**Block Level.** The objective of this next level is to evaluate how efficient the waterflood is performing, thus giving insights into the existence of future opportunities.

When the field comprises hundreds of wells, it is helpful to subdivide the field into groups defined by area. The geological limits of these blocks should be honored, such as faults or hydraulically-known barriers. However, in many instances, it will be
necessary to use wells as boundaries based on pressure boundaries or streamline simulation. Each block will include both producer and injector wells. Although one can decide the number of blocks depending upon geological features of the reservoir and location of the wells, it can be as few as five and as many as 100. However, our experience for these three cases led us to choose the number of blocks in the range of 5 to 30.

An areal allocation method will be required at this level when using wells as block boundaries. Geometrical, pore volume-weighted, OOIP-weighted, and angle-based methods are some alternatives. We recommend the motto “Keep it simple.” Remember that this level of analysis will give qualitative evaluations to help identify opportunities.

For fields with a low number of wells (fewer than 50), two or three blocks may be enough.

In addition to the previously discussed field-level practices, it is important to think about efficiencies at this point.

**Volumetric-Sweep Efficiencies (\(E_{\text{vol}}\)).** Calculating \(E_{\text{vol}}\) at this level is recommended. A calculation method proposed by William Cobb (Cobb and Marek 1997) can be used to obtain \(E_{\text{vol}}\) from production data. The proposed formula to calculate \(E_{\text{vol}}\) is:

\[
E_{\text{vol}} = \frac{B_o \cdot N_p}{V_p} + \frac{1 - S_o - S_{\text{wc}}}{S_{\text{water}} - S_{\text{wc}}}. \quad \ldots (1)
\]

With the calculated values, both for the current stage and for the estimated ultimate recovery (EUR), team discussions should focus on the following questions:

- Is there a wide range of calculated values between blocks?
- On those blocks with low \(E_{\text{vol}}\) at the EUR, is the low value because of the areal or the vertical efficiency?

Because volumetric-sweep efficiency is the product of areal \((E_a)\) and vertical \((E_{\text{vert}})\) efficiencies, evaluate the use of tracers to investigate \(E_a\). Concerning \(E_{\text{vert}}\), the use of vertical production and injection profiles, and fingerprints is recommended.

Focus on extreme performers, high- and low- \(E_{\text{vol}}\) blocks. Those blocks with low \(E_{\text{vol}}\), steep oil decline, and high GOR should have the highest potential. Therefore, the evaluation should focus on putting more water into the reservoir in these areas. The next level, pattern analysis, will help identify actions such as changing injection rates, infill drilling, and conversions candidates.

**Fig. 10**—Benchmark between fields of recovery factor vs. pore volumes injected.

**Fig. 11**—Benchmark between fields of \(W_{\text{cut}}\) vs. pore volumes injected.
For the other extreme population, when $E_{vol}$ is high, and $W_{cut}$ and oil rate are close to the economic limit, proceed to the pattern-level thinking about the benefits of shutting off water, changing flow paths, and reducing injection.

Fig. 13 shows volumetric-efficiency values calculated from Cobb’s methodology for different blocks in El Trapial field. The values range from as low as 0.1 to higher than 0.9. Note that the calculated $E_{vol}$ values are only estimates, as these blocks use allocated pattern rates.

**Pattern Level.** Pattern-level evaluations will confirm the existence of the opportunities identified at a block level and will facilitate in developing an action plan.

Hundreds of patterns may constitute a field. At this point, the focus should be on the patterns that constitute blocks with potential improvement opportunities. This is especially important if human resources are limited in looking at all patterns of the field.

In addition to the higher-level analysis already discussed, it is important to look at the following factors.

**PVI Per Year.** It is an industry practice to assume that a waterflooded field will reach its economic limit when 1.5 to 2 pore volumes are injected (Thakur 1998). Assuming a value of 2 PVI and an average waterflood field life of 20 years, an average injection of 0.10 PVI/year is obtained. Therefore, it is recommended to use a range between 0.05 and 0.20 PVI/year and investigate those patterns that fall out of the range. Patterns with low PVI/year should go into an opportunity list of patterns that require additional injection. On the other hand, if the PVI is greater than 0.20 per year, the opportunity could be to reduce injection.

**Recommended Water-Injection Rates.** It is recommended to use injectors as the center of the patterns. Once the pattern is defined, one can calculate the water injection that is necessary to achieve the target VRR for each pattern—a value of injection rate for optimum waterflood performance at this point in time. The absolute difference between target and actual injection rates for each pattern should be minimal or actions will need to be taken to reduce it further.

If the injection rate is lower than the recommended rate and pressure is at maximum condition, one should look for locations within the patterns to drill infill wells and/or convert wells.

Put together an action list that includes
- Infill-drilling candidates.
- Workover candidates.
- Conversion proposals.

Additional water requirements resulting from these proposals must be identified and discussed with facilities and operations engineers. This will allow the team to recommend realistic and timely action plans.

Fig. 14 shows an example from El Trapial field. In the early stages of injection, the water injection rate was higher than the VRR recommended to account for the cumulative voidage that was
not replaced. The last several years of injection show injection rates close to the monthly VRR targets.

**Well Level.** The well level will be the last level of the proposed methodical approach. Specific and detailed actions should arise at the end of it.

Within the key patterns selected, check that producers are pumped off. If they are not, then this should be the first opportunity to investigate before any additional drilling or workover is performed.

It is recommended to follow injector-well performance to assess plugging or fracturing of wells with rate and wellhead pressure vs. time. Additionally, use of the Hall (1963) plot to evaluate injectivity changes is recommended, especially if changes in the water-injection quality occur.

Well-test frequency should be reviewed and prioritized according to the knowledge gained from this multiphased process, such as patterns where workovers took place or where water-injection rates were modified. The team must have confidence in these measurements because capital expenditures will result from them.

**Optimizing a Waterflood by Use of the Recommended Practices**

The following example from a portion of El Trapial field shows the results that can be achieved by implementing a good surveillance and monitoring program as described in this paper.

The large drilling activity that took place in the field from 2000 to 2003 triggered inefficiencies in availability of the water-treatment capacity, water-injection distribution system, and electrical power supply. As a result, some parts of the field observed steep oil declines from the base production. Yearly nominal decline rates as high as 33% were measured.
A pilot was set up with the objective of evaluating the benefits of performing a more focused integrated water-injection management. An area was selected taking into account the following criteria: low VRR, representative area of the field, confined area, existence of spare facility capacity, availability to increase water injection, and feasibility to improve electrical supply conditions. 

Fig. 17 shows the location and pattern configuration of the pilot area. The location of the pilot is in the central part of the main block, where GOR, \( W_{cut} \), and pressure maps, along with \( E_{vol} \) calculations at a field level, indicated room for improvement.

Block and pattern analyses were first performed in the area, resulting in several action items. The work that was performed in the four inverted seven-spot patterns consisted of remedial work-overs in the injectors to ensure that water was going into all layers, increasing wellhead pressure in the injection wells, and ensuring that pumped-off conditions were achieved in producers. Additionally, a dedicated crew was assigned to the area, and the highest priority concerning energy supply was given to the area to ensure minimum power shortages.

Well-test frequency was critical to assess the results of the pilot; thus, one test per week was performed in all wells. Both producers and injectors were included in the plan.

As a result of the described work (see Fig. 18), the VRR ratio was increased to the desired value, total liquid production rate increased, and the nominal oil decline rate changed from 33 to 18% per year in a matter of approximately 6 months.

### Asking the Right Questions at the Right Level

Table 2 summarizes the different practices that can be helpful to the reader when diagnosing a field’s performance and trying to identify opportunities.

Appendix A contains a list of questions recommended as guidelines to identify areas of improvement for each level.

### Challenges

Some of the challenges that the authors have often faced when performing surveillance and monitoring evaluations include:

- Differentiating oil response because of base production or infill actions when significant activity is taking place in the field.
- Allocating fluid production and injection vertically when commingled production occurs.
- Tracking the fluid flood front and improving areal and vertical sweeps.

### Conclusions

Following a methodical surveillance and monitoring process from field to block to pattern to well levels, these conclusions are drawn:

1. Practical applications of surveillance and monitoring principles have led to arresting base decline rates in many fields operated by Chevron. For example, following this approach, the base decline rate decreased from 33 to 18% per year in the pilot area of El Trapial field.
2. The paper outlines guidelines for asking the right questions at the right level (field, block, pattern, and well). By following these guidelines, we can improve the performance of a waterflood significantly.
3. Multidisciplinary teamwork in collecting and analyzing surveillance and monitoring data and implementation of the joint recommendations are keys to managing waterfloods successfully.

### Nomenclature

- \( B_o \) = oil formation volume factor at start of waterflood, RB/STB
- \( E_{a} \) = areal-sweep efficiency, fraction
- \( E_{vert} \) = vertical-sweep efficiency, fraction
- \( E_{vol} \) = volumetric-sweep efficiency, fraction
- \( N_P \) = oil production since start of waterflooding, bbl
- \( R_s \) = dissolved gas/oil ratio, scf/bbl
oil saturation, fraction
$S_{swavg}$ = average water saturation in the water swept zone, fraction
$S_{swc}$ = connate-water saturation at start of waterflood, fraction
$V_p$ = floodable pore volume, bbl
$W_{cut}$ = water cut, percent

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Appendix A—Questions for Each Level of Analysis
Field: Overall Health of the Asset.
- What is the oil-rate (log scale) vs. time plot showing? It is recommended to make a plot of oil rate vs. cumulative oil and to note the observed behavior in the oil-rate vs. time plot.
- What level of VRR is needed to maintain reservoir pressure? If no aquifer support exists, a target value of 110% is recommended as a starting point. In some cases, such as highly depleted reservoirs, this value could be significantly higher.
- Is the water-injection-rate target being achieved?
- Is there a clear relationship between the VRR and the total-liquid- and oil-production rates?
- Is the pattern configuration appropriate? Is this consistent with the drive mechanism and the I/P ratio? Has the decision of inverted nine-spot, inverted seven-spot, five-spot, line-drive, or peripheral pattern been made on the basis of appropriate pattern selection analysis?
• What does the ABC plot show? Are there indications of water channeling? How about wells with total liquid decrease or increase?
• Which areas of the field show opportunities when looking at the GOR, $W_{cut}$, and pressure maps?

**Block: Evaluating the Waterflooding Efficiency and Looking for Opportunities.**
• When comparing PVI plots for different blocks, are the trends similar?
• What is the VRR for different blocks?
• Is there a wide range of volumetric-sweep efficiencies? Is this consistent with the field-level maps?
• Do some blocks show opportunities to improve waterflood performance?

**Pattern: Refining and Prioritizing the Opportunities.**
• Are there any patterns in need of incremental water injection or by contrast, is excess water being injected in any patterns?
• Is the PVI/year within a reasonable range?
• Should more wells be drilled (both producers and injectors)? Should more conversions (from production to injection) be performed?
• Can actions be drafted to address the opportunities? For example, new drills, workovers, or injection-rate changes?
• Has a discussion between team members taken place on actions prioritization? What is the availability of water, rigs, electrical power, personnel, and facilities?

**Well: Detailed Action Planning.**
• Are the producers being properly pumped off?
• Are the injectors showing abnormal injectivities because of plugging or fracturing?
• Is there a clear action plan to monetize the opportunities?
• Have operations, facilities, and management discussed and agreed with this plan to ensure alignment?

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