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**Name**:
**Company**: FOROIL
**Job title**:
**Address**: 10, rue Lincoln, 75008 Paris, France
**Phone number**: +33 1 80 96 88 88
**Email**: contact@foroil.com
**Category**:

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# **Title**: Learning From Past Data Tells how to Increase Production and Reserves: A Successful Four Year Return of Experience

**Author(s):** Benjamin GUESDON, Stéphane PAIRAULT, Hugues de SAINT GERMAIN, FOROIL

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**Abstract:**

This paper presents four years of successful implementation of a new methodology for identifying best re-development plans for mature fields. This is based on appropriate learning techniques using mainly past production data. This achieves a 95% forecast reliability for each contemplated plan. Massive computing allows playing 1,000,000s plans and selecting the best.

Depending on future actions on the fields (change of injection/production rates, conversion and/or drilling of new wells), this allows identifying production and reserve improvement of +20% to +100% against baseline, hence increasing the ultimate recovery factor.

This methodology can be applied to all hydrocarbon mature fields, where reliable production data have been recorded, per well, over typically more than seven years. As this is a learning process, it is valid for identifying the best development plan only with the same recovery technique as experienced in the past.

Several operators have successfully implemented this approach since 2009, leading to results already published for two fields, with and without infill drilling. Actual operational results range from +20%, (change of injection pattern and conversions) in San Francisco oilfield, Colombia to +50% (same, plus some infill drilling) in Butte Voluntary Unit, Canada, against baseline.

As the best development plan out of 1,000,000s is always a non-intuitive case, it is far better than any traditional approach: increase of production against the baseline is typically twice larger than experience based development plans, under the same technical and financial constraints.

Corresponding reserves can be re-certified, as identified plans ensure a more homogeneous production of the oil or gas in place.

This approach is a major contribution to the data-driven reservoir modeling, as it introduces an effective physics-constrained learning process. It demonstrates how re-balanced production over a mature field can increase reserves with the same recovery technique. It uses smart automated ways of massively generating and comparing development plans.

The FOROIL technology is intrinsically secure and allows to completely control the risks of current techniques on the field. Indeed, this technology, based on data (facts), is not dependent of human interpretation, and uses the same recovery technology as already applied on the field (acid jobs, water or gas injection, gas lift, sidetracked or horizontal wells…). Progressive scenarios are introduced in each field depending on investment capacity. The technology improves current technology, patterns (water injection reallocation/new conversions to injection) and allows to know where to drill new wells.

FOROIL already developed a one-year pilot of selective waterflooding in San Francisco oilfield. Similarly, FOROIL is developing new methods to implement EOR and SAGD projects in oil fields within one or two years instead of currently five or ten years.

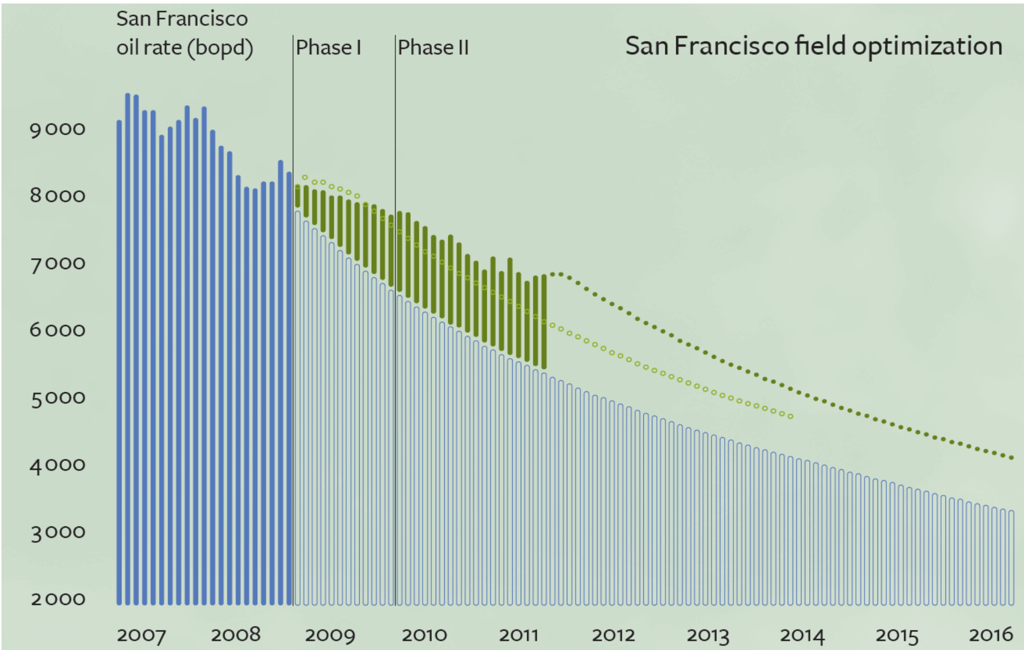


**Figure 1:** Actual production of the San Francisco optimized production scenario

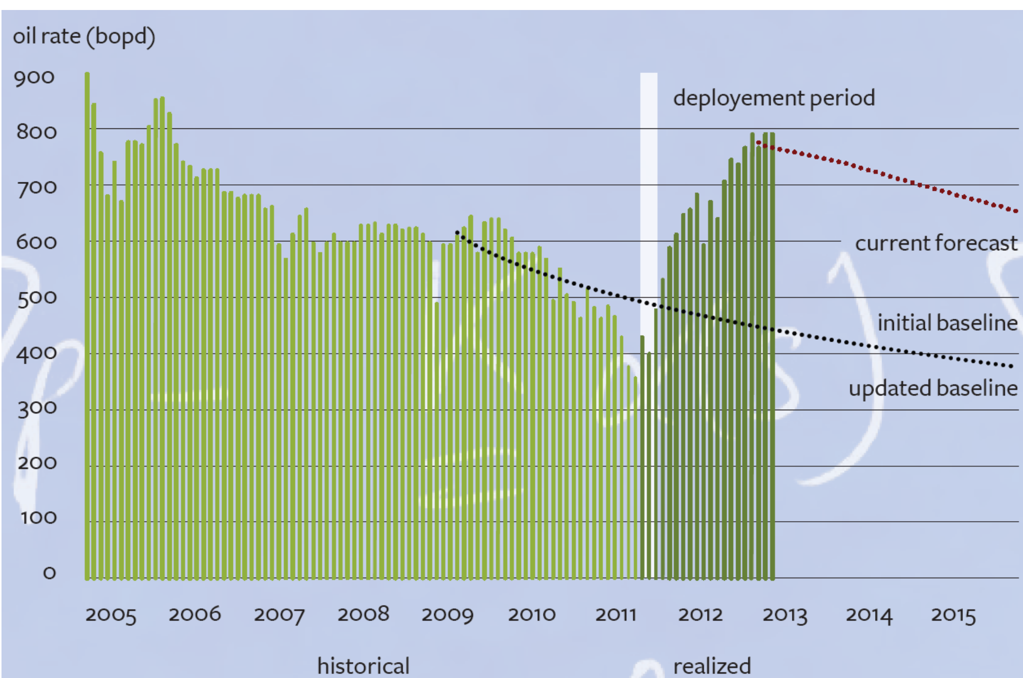


**Figure 2:** Actual production of the Butte Voluntary Unit optimized production scenario

**Introduction**

Generating additional production from mature fields is both a priority and a challenge. On the one hand, as new finds become ever more expensive, mature fields are gaining importance in the oil & gas industry with each passing year. On the other hand, mature fields offer no easy opportunity: they usually suffer from higher operating costs, decreasing oil production, ageing equipment, and a complex subsurface configuration of pressure and saturation. These issues jointly contribute to making new investment both less attractive and more risky.

This paper presents a breakthrough technology for increasing the production of mature oil and gas fields while reducing the risks related to the development of mature fields. This still recent technology has been available to the oil and gas industry for the past six years and has already been successfully applied on several fields. Two application cases completed in Western Canada and Colombia are referred to in the present paper.

An optimized re-development plan was engineered for each of those water flooded mature oil fields. In San Francisco oil field case, Colombia, the implemented plan included no investment (only a re-organization of the water flooding regime, in particular through the conversion of producers into injectors). The result was an increase of more than 20% of the oil production compared to baseline. In Butte Voluntary Unit, the implemented plan included limited investment (four new infill wells and four conversions). The implementation of this plan proved very successful and resulted in more than 50% production increase, pursuant to the initial prediction. This technology is also intrinsically secure and allows to completely control the risks of current techniques on the field.

The stakes for the oil fields is presented first. The following two sections provide details about the main pillars of the technology: (i) the general workflow for a field massive optimization project, and (ii) the methodology to obtain the best possible development plan under specified constraints. The last section is devoted to presenting the implementation of the scenarios in the oil fields.

## 1) At stake for San Francisco oil field and Butte Voluntary Unit

### a) At stake for San Francisco oil field

The San Francisco field was discovered in 1985 in Colombia (Figure 1) and has been producing from the Caballos formation. This is a highly heterogeneous reservoir in a fractured anticlinal, 3000 feet deep. The initial pressure was 1100 psia with an approximate bubble point pressure of 950 psia and oil quality varying from 23° to 28° degrees API. The field has been under a waterflood scheme since 1989. The current total fluid production is 250,000 bbl with an average water cut of 96.7%.

By 2008, the operator, Hocol S.A., had drilled a total of 193 wells consisting of 128 active producers and 76 active injectors with varied results. Due to the heterogeneity of the field, complicated by dense faulting and water injection under an unfavorable mobility ratio, the operator needed to determine the candidates for the upcoming conversion campaign; not only the location of future wells but also what injection and production rates to implement.

Before the study, Hocol made a disappointing infill drilling campaign. Then they did not expect more good infill. The study confirmed the Hocol idea. According to previous studies carried out in the San Francisco field, it was apparent that there should be a possible gain in re-arranging the water-flooding scheme, in order to better drain saturation-favorable areas, detrimentally to other less attractive areas. This would have to be done under technical constraints, not only per well, but also for the overall field, in particular total injection and production rates. Also, the financial constraint was to minimize capital expenses.

One of the key practical and difficult questions was to define how many producers should ideally be converted, where and when. As there were 99 active producers, there were $2^{99}$ possibilities (about $10^{30}$), without even taking into account when to convert them. Of course, this is even much more complex, as a conversion needs to be best implemented with every relevant rate of neighboring producers needing to be consequently adjusted. Also, other injection rates might need to be changed elsewhere, due to a surface limitation (total injection rate) or as a contribution to the readjustment of field static pressure.

Obviously the location of producers to be converted has a clear impact on field total production. The optimum number of conversions to be carried out also matters very much: if there are too few conversions, opportunities of better amanaging pressure and saturation will have been missed. Worse would be to convert too many producers: the most certain consequence of a conversion is the corresponding loss of its oil production. It needs to be compensated by better producers elsewhere. If one producer too many is converted, the corresponding incremental loss of production will not be compensated by other producers: money spent to produce less oil.

Therefore, a massive optimization process is particularly appropriate for San Franciso. As explained before, this requires, first, a relevant understanding of the field mechanisms, and then the use of an *Optimization Engine*™.

## b) At stake for Butte Voluntary Unit

Butte Voluntary Unit is a conventional oil field located in Western Canada. It started production in 1967 and was water flooded from 1970 onwards. The field was originally developed with 160-acre spacing in the 60's and 70's, following an inverted 9 spot pattern for injection. 80-acre down spacing was completed during the 80's, and 40-acre down spacing was in progress since the early 2000's. In May 2009, 82 wells had been drilled (in the scope of study), of which 53 producers and 12 injectors were still active. The most recent investments, nine wells drilled in 2004 and 2005, proved insufficient to mitigate the natural decline. The field was producing 624 bbl/d oil with 83.5% water cut.

Butte Voluntary Unit was believed to still have potential for improvement under water flooding, and it was envisaged to convert several more wells in order to complete a line injection pattern aligned with a North-East / South-West permeability trend of the reservoir. However, a field model did not exist yet, so it was an excellent case for using a bespoke tool to accurately forecast future oil production per well and calculate the costs and benefits of different possible conversion plans, and the expected yield of drilling new infill wells, accounting for their impact on surrounding wells.

The technology described in this paper was suited for designing the development plan of the field, and was selected with the objective of mitigating the natural decline of oil production with or without investment. Without investment, by making the best use of already existing hardware, taking advantage of local heterogeneities and re-shuffling the injection and production schemes in order to maximize the oil production (re-allocation of flows). With investment, by implementing the best possible development plan in order to maximize the Net Present Value of the Butte Voluntary Unit. Specifically, define the best set and locations for new investment including conversions, drilling of new infill producers (or possibly injectors), and if appropriate increasing the injection and liquid treatment capacities of the field beyond the current limits. The actual end result identified, forecasted, and achieved was a gain in excess of 50% additional oil production (with new wells) as illustrated on Figure 2.

## 2) Workflow of a Mature Field Massive Optimization Project

### a) Typical Workflow of a Mature Field Massive Optimization Project

Optimizing a mature field means identifying the best set of investments that should be committed to the field, and how to make the best possible use of available resources to exploit the remaining profitable opportunities. The full massive optimization workflow for a mature field consists of the following steps:

1. Build the production forecast tool
2. Build an automated search engine (optimization tool) linked with the production forecast
3. Run the optimization tool to identify the "optimized scenario" in every proposed development "strategy"
4. Decide the retained "strategy" (and optimized scenario accordingly)
5. Conduct the implementation on the field

The steps and terminology are explained here below.

*Step 1*. Assessing opportunities requires in the first place being able to forecast what will be the outcome of actions taken on the field, such as drilling new producers, converting some producers to injectors, or applying large changes to individual injection and production rates of wells. It is actually possible to build a reliable and accurate production forecast tool for a mature field (Ref. 1). This is the first pillar of the technology described in this paper: mature fields lend themselves to a particular type of modeling, based on educated learning from historical production data. This makes it possible to achieve high reliability and adequate accuracy of the production forecast, even for large changes applied to the set of active wells and to the wells' in and out flows. Step 1 of the process consists in developing such so-called production forecaster for the field.

*Step 2*. Once an accurate production forecast tool has been created for the field, the question remains of how to identify the best development plan. In a mature field, there usually exist a huge number of options that may be envisaged. For instance, a large number among the producers can be *a priori* considered equally good candidates for conversion. Likewise, when the drilling pattern is already rather comprehensive, many potential drilling locations at half-spacing seem equally reasonable at first sight. Furthermore, the high well density can create strong cross-flows between wells via the reservoir. In addition tophysical interactions, the often-limited fluid processing capacity in effect creates operational interactions: as soon as a new producer or injector is created, one has to re-allocate all flows of other wells to stay within the global treatment capacity. Thus, a powerful production forecast is not sufficient. One needs, and this is the second pillar of the technology, an automated search engine that will extensively explore the immense space of possible development plans, and find out the best trade-off between all competing constraints.

*Step 3*. Achieving the “best trade-off” requires setting a clear goal. It is wise, in order to develop a deep understanding of available opportunities and knowingly make investment decisions, to investigate different development strategies and compare the best solution for each one. Typically, one will want to explore the following strategies:

- Vary the set of investment allowed: no investment, conversion plan only, drilling and conversion plan…
- Investigate the differences between pursuing maximum oil production and maximum Net Present Value.
- Tune the total level of investment.
- Vary the future oil price assumption in order to challenge how robust a plan is to a downturn in oil price.
- Pursue the highest return on investment rather than the highest total value.

Each “strategy” is defined on the one hand by a set of technical and financial constraints, on the other hand by an optimization target (oil, Net Present Value, return ratio). There exist billions of “scenarios” that may be envisaged, and one “optimized scenario” that achieves the maximum target compliant with the constraints.

*Step 4*. Eventually, the solution to be implemented on the field is not directly dictated by a machine: the selection of the strategy finally retained is in essence an asset management decision that takes into account the level of spending and risk permitted, and the expected financial result both in volume and in return ratio. Before reaching this final decision, it may be necessary to investigate variations to the strategies initially proposed. The exact “implementation scenario” is defined in detail as a result of step 4. It needs to be secured by sensitivity analyses carried out by reservoir engineers, using the forecaster tool, in order for this scenario to be resilient to operational uncertainties. Step 4 also entails securing the necessary budget and resources, and realizing the detailed design of works to be conducted on the field.

*Step 5*. While the retained “implementation scenario” is being implemented on the field, it is necessary to keep the plan always current and consistent with the evolving reality of the field. The actual availability of means (existing wells and new planned wells) must be monitored. The best allocation of available means must be re-optimized regularly (monthly to quarterly) to take into account technical incidents or favorable contigencies. Importantly, the constraints deemed applicable at the time of initial optimization must be reviewed, and the implementation scenario must be re-optimized in case of material change in constraints. Therefore, the best production settings are always pursued, consistent with the real situation on the field.

Even if the two aforementioned oil fields are different (geology, exploitation strategy…), the methodology remains the same for all mature fields studied, leading to optimization of production levers already used in the past.

Foroil also develops techniques to support the development of recovery methods for which no historcal data are available yet on the field, as illustrated by a second study in San Francisco oil field.

### b) San Francisco oil field Phase II: an example of a pilot for unconventional recovery without prior historical data

The San Francisco Upper Caballos formation produces from 8 different sand bodies, KCUA-KCUF. These sands differ petrophysically and in saturations. With over 15 years of water injection, recent ILTs were proof that several sands had not experienced good waterflooding, mainly due to their less favorable petrophysical properties. A methodology to identify remaining saturations per sand, as well as design injection patterns that would remedy this will be presented.

The first optimization project in the entire KCU formation allowed to define the right balance between producers and injectors and all appropriate injection rates was identified (2008, ref. 1). A further waterflood improvement was the subject of a second optimization project called San Francisco Phase II. This entailed selectively readjusting and amplifying the injection and production per layer, and fine-tuning the horizontal and vertical injection-pattern.

## *Global Methodology*

A selective, optimized injection and production program (in limiting/stopping injection/production at certain depths) has been developed by:
(i) Using log tests available and by carrying out a five month field test, in order to collect specific production data coming from selective injection and production, and improved oil-cut and/or liquid production;
(ii) Reducing constraints related to surface equipment (water injection) in order to further boost oil production, through a massive optimization of the injection pattern.

Deliverables of this project were:

- A well-selective intervention pilot which allowed learning about of reservoir behavior from well response to production/injection parameter changes at individual layers of the Upper Caballos (KCU) formation;
- Recommendation for further layer-selective injection and production jobs;
- A learning process derived from past behavior of the whole field and from the pilot results, leading to a customized *Production Forecaster*™ for fieldwide optimizations.
- As a result of a massive optimization process, quantified and precise recommendations (injection/production rates) in order to optimize the injection scheme over the full field, with available facility capacity/limitations taken into account.

The pilot phase aimed at identifying and stimulating layers having the best oil-increment potential. A in-house mathematical approach, based on uneven perforations of producers, was used to choose layers with the best oil cut at present.

## *Layer-selective production pilot plan*

The pilot will provide a first estimate of layer contribution and possible improvement in terms of oil production.
Data are gathered by stimulating specific layers in some wells – producers and injectors – and monitoring effects in production. In order to optimize production gains during the pilot phase, highest-potential layers are first identified to conduct the pilot. The goal is to identify and stimulate these layers.
The different actions are linked to responses, in order to refine the *Production Forecaster*™. Individual actions are changes in flow rate of individually selected layers in producers and injectors. This is achieved through acid stimulation and flow control in selective injection wells. Responses are identified as change in fluid flow – interaction between wells – and oil vs. water distribution (Oil Cut).

*Key learnings from San Francisco II project*

With over 15 years of water injection, recent ILTs were proof that several sands had not experienced good water flooding, and would benefit from a vertical conformance improvement program. A methodology was developed to estimate, based on production data well (re-)perforation histories, the remaining saturations per sand layer. This was validated by a selective stimulation pilot, which in turn generated new information for refining the model and water injection. This shows how FOROIL develops new methods to implement new EOR and SAGD projects in oil fields within one or two years instead of currently five or ten years.

## 3) Technology / Modelization

### a) Achieving Reliable and Accurate Production Forecast

*A recent technology breakthrough*. The field optimization workflow heavily relies on a reliable and accurate forecast tool (production forecaster). The technology behind the production forecaster is based on the principles of statistical learning theory (Ref. 2) and was developed for hydrocarbon fields during the first part of years 2000's. This technology applies to mature enough fields only and has been available to the Oil & Gas Industry for the past six years. The essential features of the production forecaster are developed in the present section.

*Data driven analysis*. Most importantly, the production forecaster is based on a (production) data driven analysis. This contrasts with traditional grid simulators, which first rely on many assumptions or indirect measurements about subsurface properties, and involve a large number of parameters very remotely related to the production of wells. The idea is to acknowledge that for a mature enough field, historical production data have accumulated enough information to account for all relevant phenomena at stake in the field, under a given recovery technique. Obviously, there are limitations, because the field has to be mature and can be modeled only for actions similar to those already encountered in the past. For instance, it could not be used to predict the effect of deploying a polymer flood if the latter was never tried on that field in the past, at least in a pilot area.

*Limit the model complexity*. The production forecaster is a material improvement of the methods of statistical learning theory applied to a given hydrocarbon field. Basic statistical learning theory consists in generalizing the behaviors of a system based on learning from a limited set of observation samples. A major theorem of this theory emphasizes the paramount importance of modeling only those behaviors necessary to account for the training sample set. This means that one must absolutely avoid using a space of solutions wider than the strict minimum. Loosely speaking, one must build the simplest possible model embarking only the most relevant phenomena at stake in the field. If the so-called Vapnik-Chervonenkis dimension of the space of solutions is substantially larger than the number of independent training samples, there is no controlled bound on the expectation difference between model and reality in future experiments. In other words, one must avoid a model too general and too complex with respect to the limited set of available samples. This is related to the wellknown problem of "over-fitting": if a model can be parameterized to match perfectly all past data for every well and every month, chances are the parameterization is highly ambiguous and so will be the forecast (Ref. 3). Meshed simulators, which use a standard set of reservoir equations, to be parameterized with rock and fluid properties discretized on a fine grid, definitely are over-complex with respect to the statistical richness embedded in the historical data of a field, however mature.

*Pure statistics is not enough*. Yet, one should not believe that a purely statistical approach made on past-observed data is enough. Vapnik himself, the father of statistical learning theory, recognizes the following (Ref. 4): "Learning theory has one clear goal: to understand the phenomenon of induction that exists in nature. Pursuing this goal, statistical learning theory has obtained results that have become important for many branches of mathematics and in particular for statistics. However, further study of this phenomenon requires analysis that goes beyond pure mathematical models. As does any branch of natural science, learning theory has two sides: (1) the mathematical side that describes laws of generalization which are valid for all possible worlds, and (2) the physical side that describes laws which are valid for our specific world, the world where we have to solve our applied tasks."

*Petroleum physics* must be embarked. In order to apply the theory for practical purposes, one must involve the physical laws that govern the specific problem at hand. In contrast to existing statistical approaches applied in the Industry, the production forecaster does exactly this and honors the main laws of petroleum physics, which severely bind the complexity of the model, in contrast with pure statistical generalization as would be done with neural networks. The systemic consistency of the forecast is guaranteed by the very construction of the solution space. This also explains why a good accuracy is achieved not only in forecasting future field operation close to current conditions (typically, a baseline), but is also demonstrated for substantial changes against business as usual, like large injection and production rate variations, conversions of producers into injectors or new infill wells.

## b) Selected Features of the Butte Voluntary Unit Production Forecaster

*Data set to learn from*. The geological context supports the general understanding of the field but is not considered part of the training data set as such. The core data used for building the production forecaster consists of:

- A fact sheet, summarizing the field development and production history. This allows identifying the effects of deliberate human decisions not directly related to reservoir dynamics.
- Oil and rock physical properties (PVT, viscosity, porosity, permeability).
- Past production database for every well, per month and per phase (oil, water, gas, injected water, injected gas, gas lift…).
- Test books with production control parameters: monitoring of bottom hole flowing pressure and head pressure, pump settings (cycles per minute, stroke per minute and stroke length).
- Log of well work-overs (recompletion, pump upsize, stimulation or cleaning job, conversion).
- Positions of wells (at perforations, or full drain deviation for horizontal wells) on a structural map.
- Reservoir pressure measurements, inasmuch as available.

Useful additional data include the prior understanding of the drainage mechanism, aquifer influence and oil water contacts, and everything that can be used as a tracer, such as water salinity when there exists a contrast between formation water and alien water fed into the injection system.

*Reservoir pressure*. Reservoir pressure measurements are often scarce, although it is a critical dynamical variable of the field. For the Butte Voluntary Unit, the available reservoir pressure measurements consisted of about 80 static gradient or build-up tests spanning from 1970 to 2008. Available tests provided useful control points on the range of reservoir pressure experienced locally. The production forecaster provided effective pressure maps of the field, showing high-pressure regions in the eastern and western part of the field.

*Well-well cross-flows*. Observed in the historical production data, inter-well cross-flow was properly modeled in the Butte Voluntary Unit production forecaster. A change in well flow can propagate throughout the field, for instance via the reservoir pressure, and in fact account for effective well-well influence that are not limited to the nearest neighbours. Producers farther away are of course less sensitive to such local change of injection. However, their response is not nil because the entire Butte Voluntary Unit is connected via the circulation of multiphase fluids.

From an operational viewpoint, while it is natural to increase injection in order to support nearby production, it is much less intuitive to reduce a producer's outflow for the same purpose. However, this alternative way of supporting the field pressure is a lever used by the optimization tool when seeking an optimum compatible with the total field injection constraint, or compatible with the locations of existing injectors when conversions are not allowed or too costly. Note, however, that the response times differ between both cases. Indeed, the production forecaster may involve several time scales in conjunction, if it proves necessary to account for the production data. This is the case for the Butte Voluntary Unit production forecaster, and the time-dependent response of neighbors is quite different when varying an injector than when varying a producer.

*Water cut dependency on liquid rate*. Another important behavior that was observed in the production data, and rendered in the production forecast model, is the existence of a strong relationship between the water cut and the liquid rate for many producers. For several wells, it is observed on the production data that the water cut has been in the past subject to sudden increase resulting from a related increase of the liquid production. Furthermore, this effect is reversible to some extent, so that the water cut resumes a lower value shortly after reducing the liquid production rate.

*Two-stage water breakthrough*. Careful analysis of the production data revealed the existence, for a set of wells located in the center-west part of the field, of a two-stage evolution of the water cut over the well life cycle. The production forecaster embarks this behavior, which is well established by the production data in a limited and identified part of the field.

## c) Identifying the Best Development Plan

*Distorted reservoir configuration*. Oil and gas mature fields have developed during the course of their production history (typically more than ten years) a high degree of complexity. When first starting production, reservoir pressure is uniform, but heterogeneities exist in the petrophysical properties of the reservoir. After many producers have been drilled and operated for a long time, distorsions have developed since the wells have locally depleted the field and decreased saturation in a non-uniform fashion. Injectors also heavily impact both reservoir pressure and saturation. Quite often, the impact of human decisions have also strongly distorted the reservoir configuration: parts of the field might have been developed by different operators under different concepts, a temporary downturn in oil price might have cancelled investment opportunities that were never considered again afterwards, lagging injection capacity might have led to concentrating voidage replacement only in selected areas of the field, etc. As both saturation and pressure have grown heterogeneous, the precise way of producing the field, that is, the exact tuning of every individual injection or production rate per well, matters a lot more (Reference 1). Capability to improve production by revisiting production and injection rates can increase the reserves typically by +10% to +20%.

*Huge combinatorial complexity.* In a mature field, while on the one hand, outstanding opportunities for drilling (respectively conversion) are not obvious to pinpoint, there are on the other hand many equally reasonable locations (respectively wells) to consider as valid candidates for infill drilling (respectively conversion). This leads to a huge combinatorial complexity of potential development plans. Consider for instance a combined drilling and conversion plan involving 8 new wells among 20 sweet spots locations and 7 conversions among 69 candidates: this represents 136 hundred thousand billion possible plans. And this covers only the main investment decisions: there remains to fine tune every individual well flow. Even with very good insight, ordinary reservoir engineering methods cannot possibly assess a sizeable fraction of that and find their way to the best plan.

*Fast forecast.* It is a useful consequence that the production forecaster described in the previous section, which was first designed to achieve best possible production forecasting accuracy, is actually very quick to compute, owing to the comparative simplicity imposed on the model. Moderate complexity makes it possible to run a forecast in a matter of seconds on up-to-date farms of computers. The method also relies on recent progress achieved in computing power, and it would not have been practicable in the early 2000's. State-of-the-art calculation software is used, including processing routines for large databases, farmed multicore microprocessors and parallel computing. It really is the combination of a reliable production forecast tool based on recent mathematics, the comparative simplicity of the resulting model, and the advent of ever more powerful computers, which made the whole technology nowadays realizable.

*Optimization know-how.* In spite of such computing speed, it remains impossible to comprehensively run all imaginable scenarios in the numbers exemplified above. Nor is it smart to pick and test thousands of them randomly like in a Monte-Carlo approach, as there is little chance this would capture a very good scenario. Specific optimization techniques need to be developed, in order to properly explore the vast amount of possibilities in an informed manner, so as to achieve comprehensiveness and relevance in the choice of scenarios to be played. A hybrid threefold optimization technique was developed in order to select and play hundreds of thousands of production scenarios combining heuristic, deterministic, and non-deterministic approaches.

In order to limit the number of production scenarios to run, reservoir engineering reasoning is used to set some rules and discard "unefficient" scenarios without running them. This is the heuristic component: optimizing an oilfield is different from optimizing some abstract problem in absolute, and allows educated simplifications *a priori*.

Deterministic methods are also used to rapidly converge towards a local optimum. Such methods are classically used when there exists a single optimum in a locally convex landscape, which can be found through a continuous path of consecutive scenarios. At each step, the next scenario is a small variation from the previous one, and there are systematic ways of exploring around by not testing all close scenarios in order to converge towards the best.

However, one should not remain trapped around a local optimum and must be able to consider radically diffent solutions that cannot be identified by a step-by-step continuous search. Non-Deterministic optimization techniques are required when binary decisions must be evaluated (such as drilling a new location or converting a well).

### d) The Field Optimization Tool

*Massive Optimization in practice*. The massive optimization exercise is to some extent reverse to the forecasting exercise. When building the production forecaster, inputs are given and the forecaster must be designed and calibrated so as to deliver computed outputs. “Inputs” means all production control parameters defining how wells are operated over time, which commonly consist of:

- Actual availability of every well (production or injection hours).
- Actual dates and locations of conversions performed, new wells drilled, and other work-overs.
- Production parameters applied, for instance bottom hole flowing pressures and injection rates.

Outputs are the computed production rates of each phase (oil, water, and gas when relevant), monthly, for every well. Once the production forecaster has been made available, the game becomes to find out the best set of inputs to be enforced in the future in order to generate outputs of maximum possible value. The global value of outputs is evaluated by a “gain” function such as cumulated oil production or financial Net Present Value.

*Constraints*. Both technical and intentional constraints are imposed on inputs and outputs. Wells are subject to individual technical constraints:

- (Producers) Minimum bottom hole flowing pressure, for instance related to the bubble point and to the minimum acceptable submergence of pumps.
- (Producers) Maximum liquid production rate, related to the maximum pump throughput, and sometimes to the well design and completion.
- (Injectors) Maximum injection pressure, related to the network design at the surface end, and related to the rock fracturing threshold at the bottom end.
- (Injectors) Maximum injection rate, for instance related to the chokes and tubing diameter.

One must also be cautious to use the production forecaster within its validity domain, that is, not too far away from the conditions seen during the learning period in the training data set (yet these can be far from current operation). For instance, injection rates of existing injectors are intentionally limited to 130% of their historical maximum, in the specific case of the Butte Voluntary Unit, and a ceiling is also set on the rates of new injectors, consistent with other injection rates in the area.

Perhaps more important than individual well constraints are the global field constraints, because those drive the need for an optimum allocation of limited shared resources among wells:

- (Field) Maximum fluid processing capacity.
- (Field) Maximum injection capacity.

Scheduling constraints were enforced in order to produce only realizable scenarios:

- The starting date of investment allowed for a prior preparation period.
- The number of drilling was limited per month (rig availability), and per year (duration of the frost period).

Finally, intentional constraints serve at defining different development strategies:

- "No investment" strategy: only re-allocation of in and out flows, no conversion or drilling is allowed.
- "No new well" strategy: re-allocation and conversions are allowed, but not infill drilling.
- "Full investment" strategy: re-allocation, conversions, and infill drilling are allowed.
- "*X* new wells strategy": re-allocation, conversions, and drilling up to *X* new wells are allowed.

*"Gain" function and financial parameters*. As a general rule, optimization sought to maximize the Net Present Value, in order to account for all operational and capital costs of the optimized scenario, and assess the financial value of proposed development opportunites. However, computing the Net Present Value involves additional assumptions, in particular about future oil price: for strategies involving no or moderate investment ("no investment" and "no new well") it made sense to run the optimization also for maximizing oil production regardless of the (limited) costs, and independently from the expected sale price of oil.

The Net Present Value function included a faithful representation of all costs incurred. Operating costs had a fixed part related to the number of active wells and a variable part proportional to production. Capital expenditures were specified for drilling, conversions, and enhancing the field injection capacity (thus releasing the current constraint). Royalties applicable to each well (depending on drilling date, location, and cumulated volume produced) were exactly encoded. As is customary in the industry, a financial discount rate was used to account for the time value of cash flows. It is extremely important, in order to reach trustworthy conclusions, that the Net Present Value reflects the economical reality of the field. Of course, future oil price is also a key assumption: sensitivity of optimized scenarios to variation of the oil price was always assessed.

*Candidate opportunities*. As outlined above, many potential opportunites were available. In a mature field, one must avoid filtering out options *a priori*, because investment opportunities are neither outstanding nor obviously invalid. This is the very reason why a fine forecast model and a powerful optimizer are needed. For the Butte Voluntary Unit, all producers (69, including suspended ones) were considered for conversion, and a comprehensive set of sweet spots (20) was considered for drilling.

*Full investment optimized scenario*. Given the computational speed of the Butte Voluntary Unit model at the time of the study, most optimization runs spanned 20,000 to 30,000 iterations. Since each iteration manages 20 scenarios in parallel, this represented 400,000 to 600,000 differents scenarios configured, run, and evaluated under each strategy. This was sufficient to converge to the optimized scenario, thanks to the advanced optimization algorithms used.

The "full investment" optimized scenario entailed drilling eight new infill wells, converting five active producers to injectors, and re-opening two suspended producers as new injectors. As explained in the next section, a balanced decision was made in favor of a higher return ratio for a more limited investment, and to implement a first batch of four new infill wells and four conversions, focusing on the most profitable opportunities in priority.

## 4) Implementation in the fields and results

### a) Massive optimization of the San Francisco field

A specific *Optimization Engine*™ has been calibrated using heuristic, deterministic and non-deterministic mechanisms, as explained above. The "cost function": to maximize the cumulative oil production of the full KCU reservoir over the next five years, starting from October 2008.

Technical constraints for wells were defined according to their historical values, in such a way that the *Production Forecaster*™ only calculates within a space which has been learnt from in the past: injection rates can vary from zero to their maximum historical value (+ 20%), and bottom-hole flowing pressures (BHFP) of producers are kept above minimum observed values.

For any set of technical and financial constraints, the *Optimization Engine*™ has computed hundreds of thousands of different production scenarios (hence the "Massive Optimization" name). This striking and exceptional amount is actually possible, as the *Production Forecaster*™ shows quite a high computational speed: it takes less than one second to calculate a production scenario over five years, for a given set of production parameters. Apart from smart programming, such speed is essentially due to the limited number of parameters (related to a small enough VC dimension) that is necessary for building the model of the *Production Forecaster*™.

#### Identification of the best production scenario

The constraints defined for the scenarios to comply with were:

- Technical constraints for producers and injectors same as in the baseline.
- Conversion of producers allowed.
- New infill wells not considered.

After calculating 400,000 scenarios, the optimization process converged to a best scenario showing a 1.2 mmbo above the baseline, that is +12% of the remaining reserves. This scenario would require the conversion of seven identified producers, at the beginning of the implementation period. Injection and production rates are defined for every well, over five years.

It appears that the Optimization Engine™ recommends to fully rebalance the injection and production rates per well. The northern part of the field has experienced a global reduction in fluids, in order to favor better areas in the southern part.

### Implementation and results

The optimized scenario has been quickly and effectively implemented over the course of 3 months. Of course, there were some instances where production parameters could not be exactly implemented in the field, in particular what concerns injection rates. Regular re-optimization scenarios have been calculated over passing months, in order to take into account such limitations and opportunities to inject more (or less) than the original constraints. This is possible because the Optimization Engine™ is quick to run.

Actual production results in the field very closely match the forecast for the optimum scenario: expected additional production has been achieved indeed. This is pictured (Fig. 1) as green bars against the baseline in blue and the optimized scenario in green dots.

## b) Massive Optimization of the Butte Voluntary Unit

The technology presented in this paper is strongly result-oriented. It is intended to yield pragmatic recommendations quickly applicable on the field. We review in the present section the actual stages and progress undergone throughout the project. The main phases and milestones of the project are summarized below.

### Initial Study

The initial study was completed within four (calendar) months, from June to September 2009, and delivered the key expected conclusions. A blind test allowed improving and validating the production forecaster, the baseline oil production was determined, and all potential opportunities were identified.

- Amongst 69 candidate wells for conversion, five profitable conversions were identified.
- Amongst 20 candidate sweet spots for infill drilling, eight drilling locations were identified and ranked.
- Four conversions and two drilling locations would survive the lowest oil price assumption, while a ninth profitable drilling location was identified under the highest oil price assumption.
- Drilling new wells triggered the need for additional supporting injectors (in general, two more conversions with respect to a plan involving only conversions).

### Scenario Selection

Based on the above conclusions, there remained to select exactly which scenario to implement on the Butte Voluntary Unit, depending on the allowed level of investment and expected return ratio. A detailed comparison of more and more comprehensive drilling plans was completed in terms of total Net Present Value gain on the one hand, and return ratio on the other hand. These additional investigations and optimization runs were completed from October 2009 to April 2010.

During that period, intensive use was made of the production forecaster in order to evaluate the pros and cons of various ideas or variants to the proposed development strategies.

The scenario selection period was also used to secure the resources and legal authorization for implementation, and to investigate more detailed questions that had not been embarked in the production forecaster. For instance, the conditions of casings were not available for every well at the time of the initial study: they could now be reviewed in detail for the restricted set of proposed conversions, together with costs and requirements for tying-in the new injectors to the surface network.

Likewise, a precise design project was prepared for the proposed new infill wells.

Eventually, a reasonably ambitious development plan was decided, namely:

- Drill four new infill wells, out of the eight proposed in the full investment optimized scenario.
- Perform four conversions, out of the seven proposed in the full investment optimized scenario.
- Carry out the injection facility upgrade, as proposed in the full investment optimized scenario.

## Implementation

Moving on to field implementation was importantly delayed by the harsh reality of terrain. Indeed, although a clear course of action was decided since April 2010, exceptional adverse weather conditions impeded actual deployment of new investment and production settings on the field until summer 2011. During that time, not only was it impossible to carry out significant field works, even normal maintenance of existing wells was jeopardized by the poor accessibility to the field. The spring and summer of 2010 were extremely rainy and the ground resulted constantly flooded, making access to the field either impossible or forbidden in order to avoid excessive wear out of roads and tracks. Then, the winter of 2011 was unusually mild, so the ground rarely frozen, a mandatory condition for rigs to operate. Thus, although some wells could be drilled and some new injectors could be equipped, none of them could be tied-in to the facilities until later that year. One can see on the field production curve (Figure 1) that the Butte Voluntary Unit was producing less than its baseline during that period.

Eventually, from June 2011 onwards, the ground dried out and normal operations could be restored. New injectors and new producers became live between June and August 2011, and new production settings – essentially the individual injections rates – could be enforced. Still, the revised baseline shows a little kink reflecting a group of wells that were still down during the autumn of 2011, awaiting repair in January 2012.

Quickly after the actual deployment of new producers and injectors, the oil production soared to almost 800 bbl/d, back to levels unseen for the previous six years. Figure 2 shows (red dots) the latest production forecast of the implemented optimized scenario for the years to come. The demonstrated additional production is +63% above the baseline.

## Conclusion

This paper presents a technology developed and industrialized in the recent years for increasing the production and reserves of mature fields and reducing the risk of current techniques used in the field. This technology is intrinsically secure and allows to completely control the risks of current techniques on the field. Indeed, the technology, based on data (facts), is not dependent of human interpretation and applies same recovery technology as already applied on the field (acid jobs, water or gas injection, gas lift, sidetracked or horizontal wells…). Progressive scenarios are introduced in each field depending on investment hypotheses. The technology adjusts current technology, patterns (water injection reallocation/new conversions to injection) and allows to know where to drill new wells.

Said technology relies on two main breakthroughs. Firstly, the ability to create, for each mature field, a reliable and accurate production forecast tool. Secondly, using this forecast tool combined with powerful optimization techniques, to identify the most valuable future development scenario to implement on the field, among a huge number of possibilities.

This technology is now fully validated and proven on several fields. It is illustrated in the present paper by two successful applications to conventional water flooded mature oil fields in Colombia and in Western Canada and a successful one-year pilot of vertical conformance optimization in San Francisco oil field. Future development is to extend this technology to EOR and SAGD in mature oil fields to reduce the time of the implementation to one or two years, instead currently five or ten years.

## References:

1. Andrés Felipe Suárez, David Soto, & Hubert Borja, SPE, Hocol S. A.; Remi Daudin, FOROIL “Massive Optimization Technique Improves Production of Mature Fields: San Francisco, Colombia”. SPE-138979-PP.
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## This paper includes some parts of the following SPE papers:

1. Andrés Felipe Suárez, David Soto, & Hubert Borja, SPE, Hocol S. A.; Remi Daudin, FOROIL “Massive Optimization Technique Improves Production of Mature Fields: San Francisco, Colombia”. SPE-138979-PP.
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3. S. Pairault, R. Daudin, FOROIL “Smart Learning from Past Data Yields 50% Incremental Oil Production” SPE 164919-MS