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Development of a Field Scale Polymer Project in Argentina

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Abstract

After 6 years of continous polymer injection in El Corcobo Norte field, pilot's preliminar evaluation showed promising results. Although the evaluation is still ongoing, polymer technology economics look good enough to sustain a project expansion.

Located in the Neuquén Basin, El Corcobo Norte field is an unconsolidated, underpressurized, strongly water-wet sandstone reservoir, producing medium-heavy oil from the Centenario Formation. Reservoir drive is waterflood, which has been implemented since the beginning of the field's development. Up to date the field has more than 650 producers and 350 injectors, mostly developed under 20 acres, inverted 7-spot patterns. Main challenge for this field's operation is sand production and chanelling issues that leave bypassed or undrained oil zones.

Since 2008 EOR technologies were evaluated in order to increase ultimate recovery factor. As a results of this screening, polymer injection was chosen as the first candidate to test in the field. Polymer pilot design and execution was described in SPE 160078 ("Desing and Execution of a Polymer Injection Pilot in Argentina") and pilot preliminar evaluation was presented in SPE 181210 ("Evaluation of a Polymer Injection Pilot in Argentina").

Based on the pilot's learnings, an expansion project was designed to maximize the use of the available capacity and upscale polymer injection as efficiently as possible, considering field's current operational conditions.

The present article will focus on describing the upscale of the polymer pilot and the strategy to optimize the project's operation.

Introduction

A polymer injection pilot started on January 2012, in a 6 pattern zone of El Corcobo Norte field. Producing medium heavy oil from Lower Centenario formation, this unconsolidated sands have outstanding waterflooding performance, nevertheless improving its mobility ratio shows interesting results in lab testing. This motivated the operator to conduct further investigation and evaluate polymer injection technology in a field trial. Pilot objective was not only validating achievable incremental recovery, but also narrowing uncertainty regading polymer injectivity and injection pressure behavior under polymer injection.

The results of this field test were evaluated as positive and expansion cases were analyzed to upscale the project and affect a larger area of the field with this technology to develop reserves. Probabilistic analysis was included in the study in order to obtain a response curve distribution for the expansion cases.

Facilities design was focused on optimizing existing facilities for water treatment and softening, as well as polymer hydration and injection solution distribution. This article will address the design concept for the expansion project, the implemented workflow for upscaling and the practice application for pilot's learnt lessons for the expansion project.

Pilot Summary and Operation Description

Polymer technology was selected to try in a fully developed field area with a mature waterflood process. Pilot production was isolated in a separate surface facility to enhance quality of incremental production measurement and avoid any potential operational issue in water oil separation that polymer presence may cause to the rest of the field's production. The pilot involves six inverted 7- spot patterns, therefore 6 polymer injectors and 22 producer wells. Selected concentration for the field trial was the product of lab design combined with numerical simulation.

Water source for this project is fresh water from a nearby source, which is softened on site with the use of exchange resins Onsite heaters are on service only during winter season periods in order to better hydrate the polymer in maturation tanks. Water composition and reservoir fluid description was covered in previous publications by Hryc *et al*. SPE 160078 and SPE 181210.

Polymer plant dissolves the high molecular weight HPAM to a mother solution polymer concentration that gets diluted afterwards to the design concentration on an injector well basis. Pilot design contemplates injecting 500 ppm active polymer targeting 20-25 mPa.s (@ 38°C, 7 1/s).

Over the past six years, pilot operation ran without any complication, achieving target viscosity for process design. Aside from eventual power shut down or pump failure, no operational incidents were reported. No accident was registered on the polymer plant, onsite lab or the pilot- dedicated production facility. Polymer quality proved to be stable and repeatable. Field production was received in surface facilities, and polymer presence, once detected in produced fluid, generated very little modification in previous water oil separation process.

Project surveillance was performed as planned and viscosity, injection pressure, and water quality variables were registered daily.

Pilot zone sands show tendence to injector - producer channeling and in the pilot patterns 2 producers have been shut prior to pilot implementation. This factor caused that only 2 producer wells were defined as central, surrounded only by polymer injectors (See pilot zone in Figure 1). Along with the pattern centered in the injector, this brought along a higher complexity at the time of project evaluation because of the dilution effect. During the pilot evaluation 2 other wells suffered injector - producer channeling, and they were both remediated by the injection of resin and sand, method commonly used to recover channeled producer wells in El Corcobo Norte field. The methodology is described in articles published by Kruse *et al*. in 2014 and 2015. After treatment, recovered wells in the pilot zone continued showing response, lowering water cut as a result of polymer injection.

Pilot expected oil production response showed a different profile than the initial prognosis obtained through numerical simulation; however reserves addition was proven by analyzing resulting production in comparison to oil production baseline. Injection pressure behavior under polymer injection was one of the most important learnings from the pilot, since most of the reservoir engineering tools are poor to predict this variable's trend in a constantly stimulated reservoir.

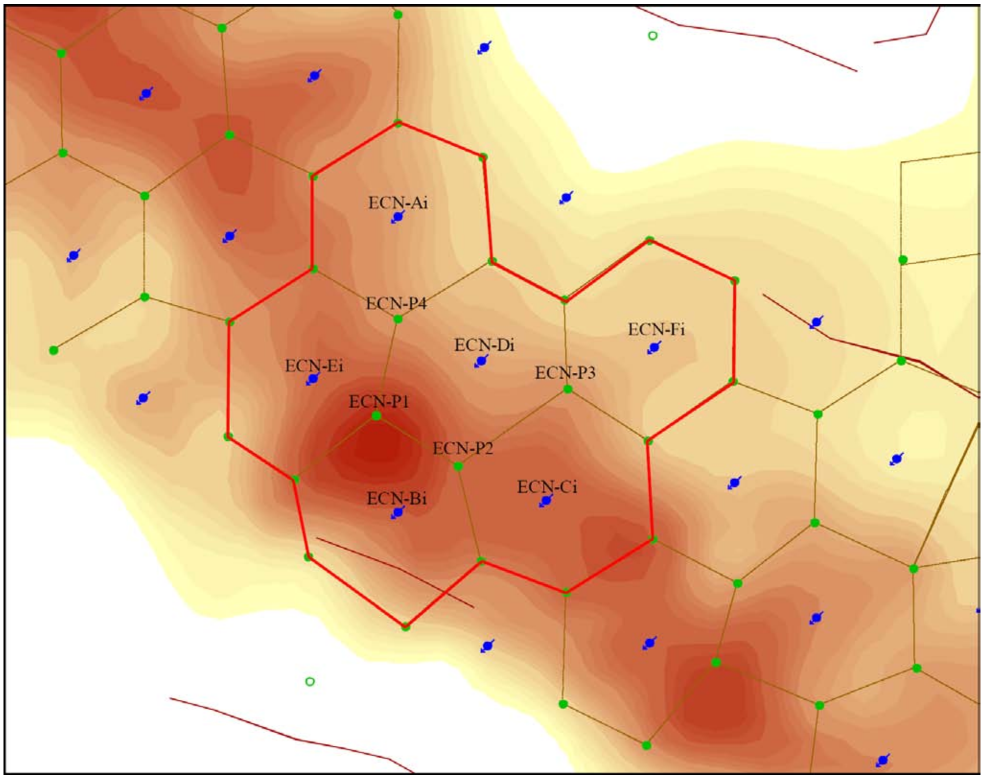


Figure 1—Pilot Zone

Production Response and Technology Evaluation

Pilot resulting production was imputed to history match the numerical simulation model for this field's zone. Two different models were used: an initial model that only covered the pilot zone (one injection satellite) and a second finer scale model that covered almost half of the field main area (similar sizing as what is later on conceptualized as expansion zone). First model was used for pilot design and sensitivity analysis, and it was the initial tool to follow up the project at the beginning of polymer injection. Once the more comprehensive and detailed model was available, it began to be used for surveillance and history matching purposes. Nevertheless both numerical models represent the same phenomena and count with same limitations to represent certain aspects. Figure 2 shows both single injection satellite and expansion zone models.

For pilot design, simulated production response showed a plateau at the beginning of polymer injection, which duration was related to many factor, s among which injection rate, polymer adsorption-retention, polymer degrading are the most significant. In comparison to the initial prognosis, pilot's response plateau extended beyond predictions due to a drop in injection rate. This occurred during the first 3 years of polymer injection, where injectivity loss was not compensated by an increased injection pressure (surface lines limitation). Also a higher polymer adsorption had to be used in order to history match field data. Even though adsorption was higher than the P50 value used as initial estimation, history matched adsorption still lies within the range of measured values in the lab stage (2.5 – 8 mg/kg rock). Because of the way the process is modeled, effects like polymer chemical/ mechanical degradation occurring in the reservoir, polymer retention and polymer adsorption would all throw same simulated production response as a higher polymer adsorption, since they all remove available polymer amount for mobility control enhancement. By the use of this tool only, no control in the separate effects is describable. Figure 3 shows the extended plateau for field response and its comparison with pre- defined production baseline.

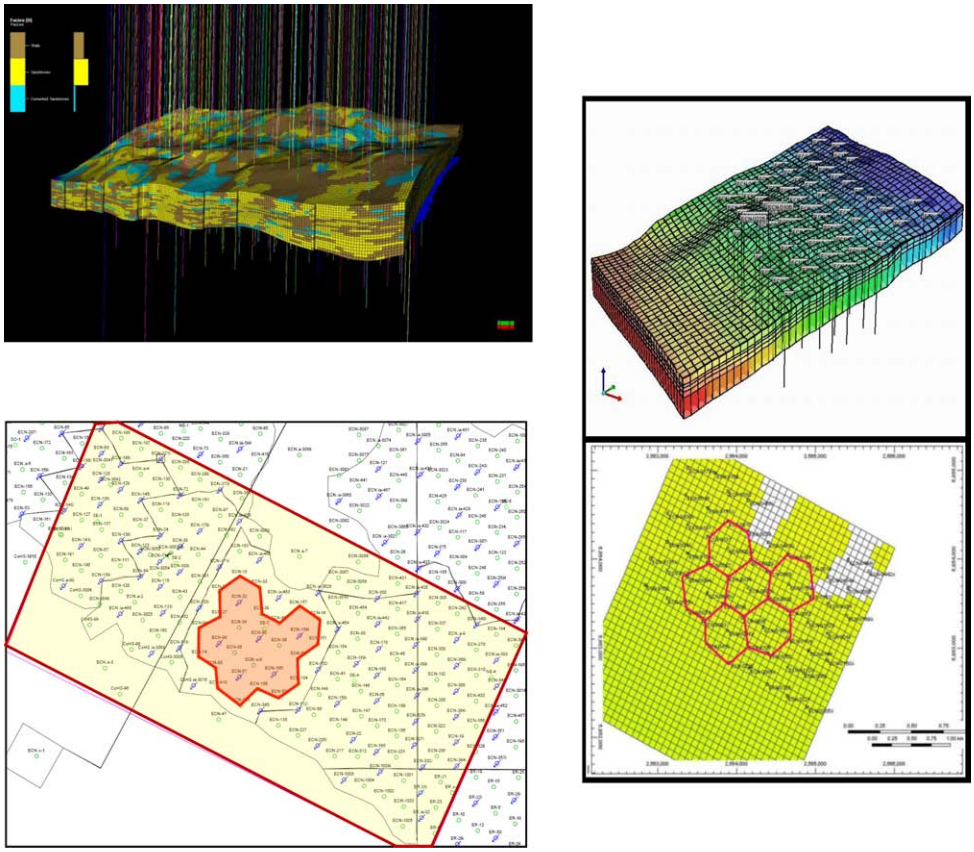


Figure 2—Pilot Scale Model and Comprehensive Model

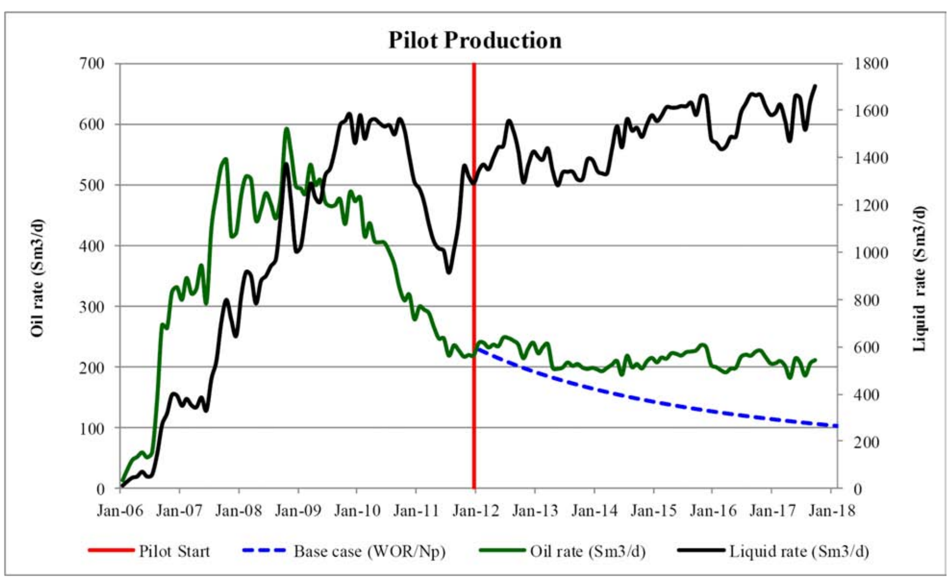
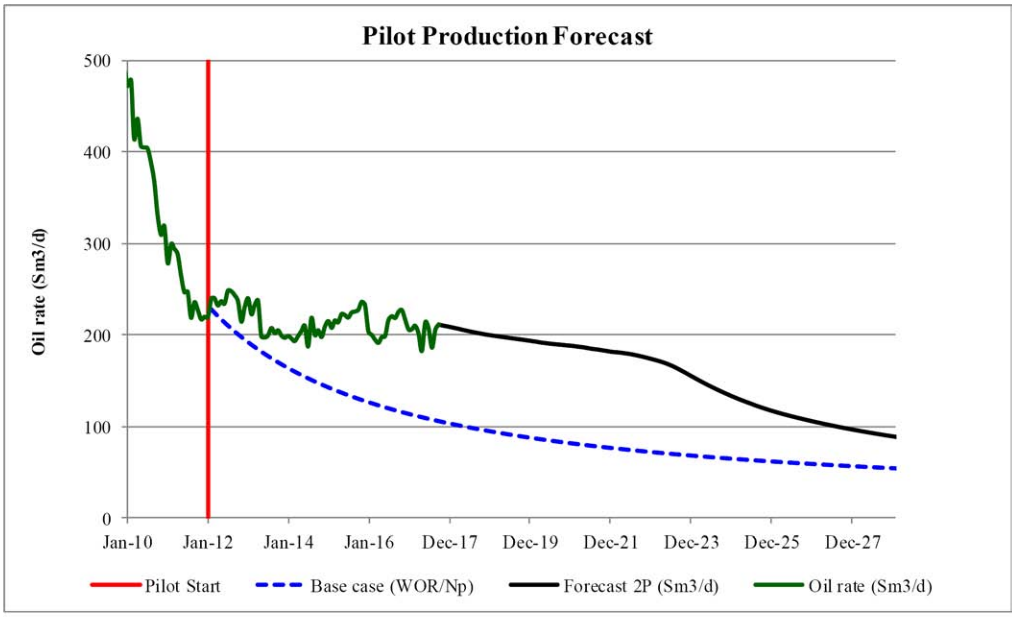


Figure 3—Pilot Production Response

In the comprehensive numerical model a detailed probabilistic analysis was conducted in order to obtain ranges for recovery belonging to the baselines, as well as for the polymer injection response. For unconsolidated sand-producing reservoirs numerical simulation models that don't account for the geomechanic effects there's a limited use in predictability. Nevertheless they tend to be a used and accepted tool for incremental comparisons, since neglected effects show in baselines as good as in incremental cases. To asses this aspect and couple geomechanic effects with dynamical simulation, the company is conducting a research study involving lab measurements and stress modeling that will not be covered by the present article.

In order to cover the uncertainty in baseline and incremental cases an assisted history matching tool was used in order to run more than 1000 cases that were later on used to generate an incremental production distribution curve. Figure 4 describes the incremental production distribution curve for pilot zone, where it's appreciated that expected incremental recovery factor for the pilot lies in the expected range. This analysis was extended to all the satellites involved in the expansion zone, as it will be shown in the following section.



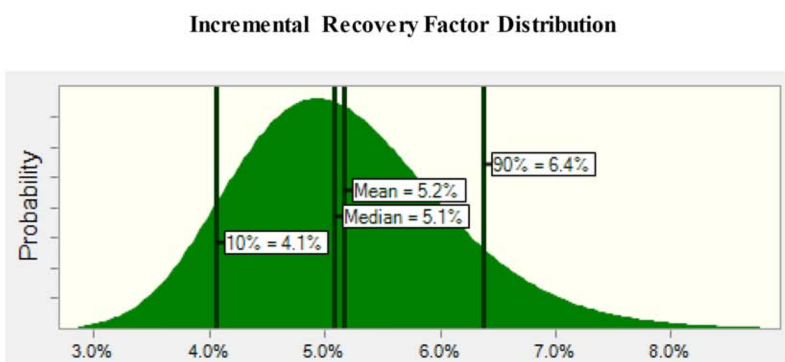


Figure 4—Pilot Production Response and Incremental Recovery Factor Distribution

Polymer concentration validated in the pilot was 500 ppm active solution high molecular weight HPAM, targeting 20-25 mPa.s (@ 38°C, 7 1/s), which is also the condition used to analyze an expansion case.

Upscale

Once reserves addition was proven for the pilot, an expansion case was designed in order to asses a field scale project economy. First of all, the size of the expansion project had to be defined and in the case of El Corcobo Norte polymer project, limiting factor is fresh water rate available for polymer hydration. Since the concesion owns an existing contract with local authorities for water supply, available water rate delimited the zone susceptible to polymer injection with a fresh water design. Total injection rate and polymer consumption for the project are shown in Figure 5.

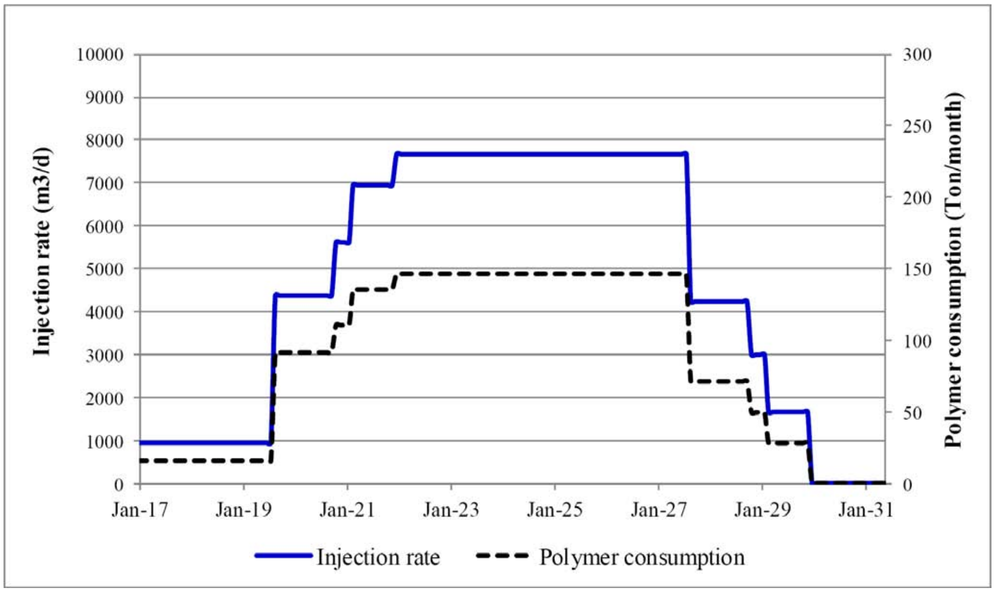


Figure 5—Expansion Injection Rate and Polymer Consumption

Accounting for the limited water resource and injected rates in nearby satellites, the expansion project would incorporate five additional satellites to the existing polymer pilot, going up to a project that involes 126 producers and 78 injectors. With this design the dilution effect would not be present, considering more than 70% of the producers would be totally surrounded by polymer injectors. Figure 6 shows the field scale project expansion zone. Injection zone VI would be incorporated once injection zone I (pilot zone) no longer injects polymer, timeframe after which polymer shows no upside in comparison to water injection (estimated time through simulation is 2022).

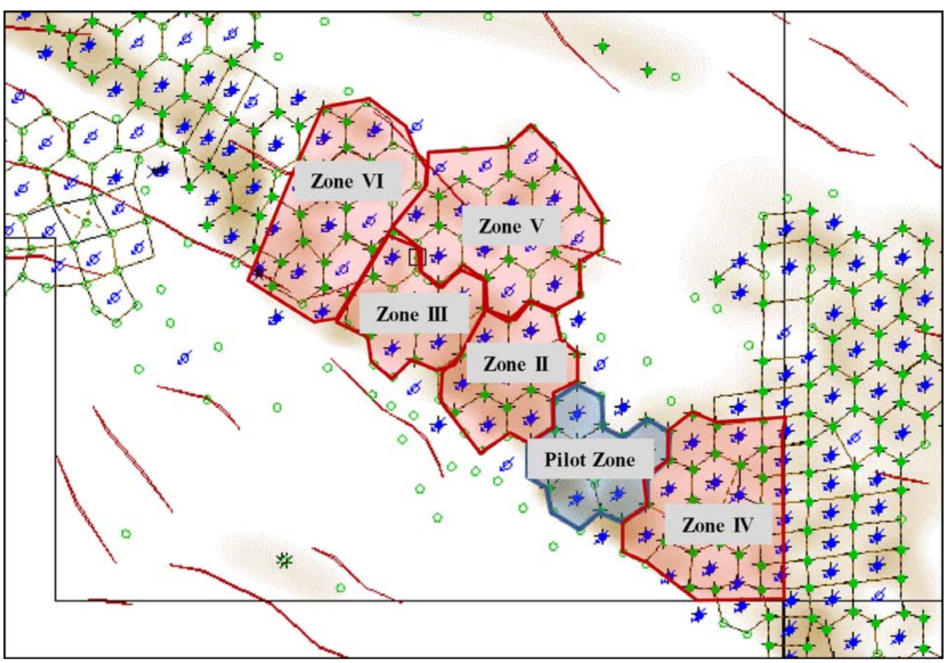


Figure 6—Field Scale Project Expansion Zone

To generate scenarios the probabilistic production analysis described for zone I (pilot zone) was extended to the rest of the modeled zones that are part of the expansion. Considering the comprehensive numerical model covers part of the expansion zone, an analogic workflow was used to upscale the polymer response to non simulated areas, and sensitivity analysis was also extended in order to include them in the project total response. The result for this analysis is shown in Figure 7.

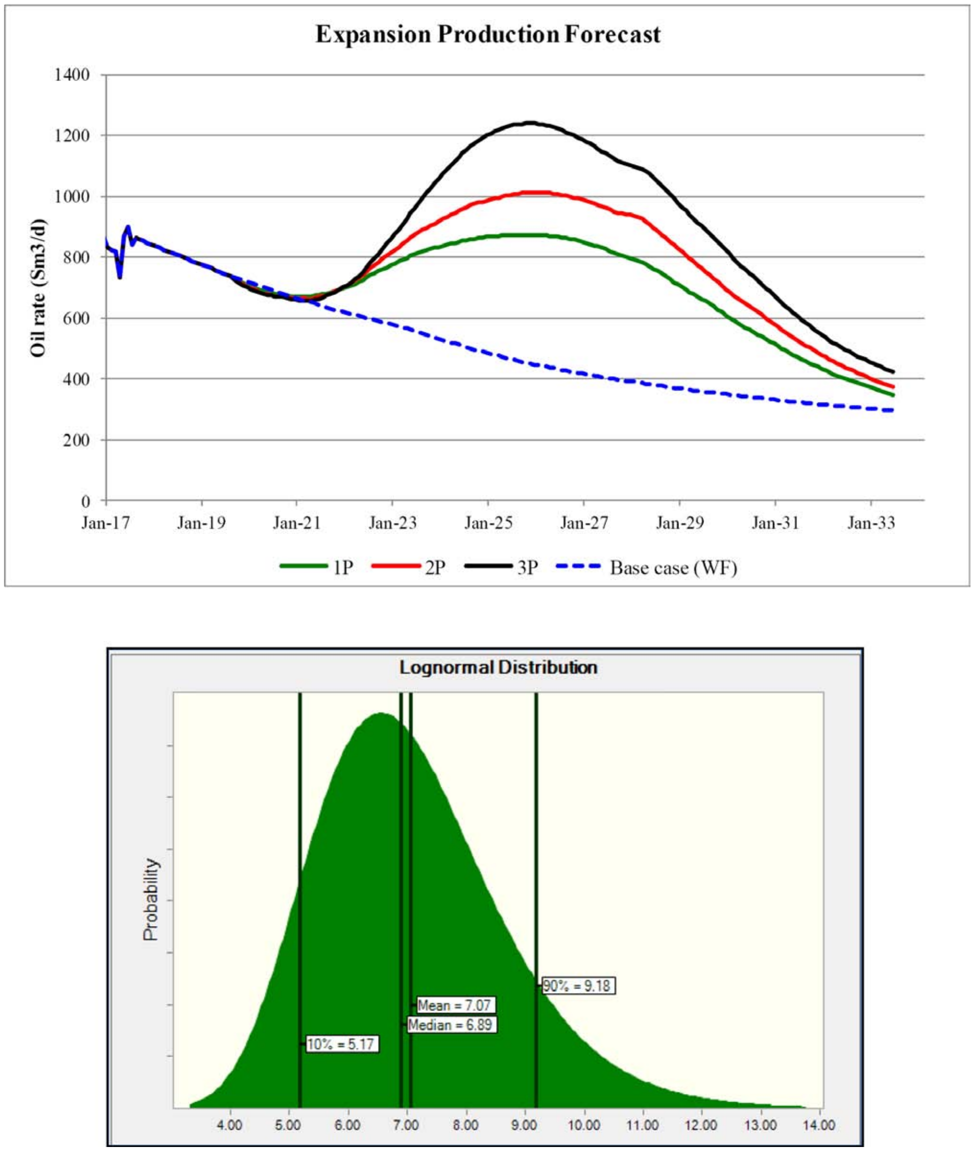


Figure 7—Expansion Production Response and Expected Incremental Recovery Factor

Production constrains such as constant injection rate and fluid extraction level would also be a premise in the project upscale, and therefore in order to assure injectivity surface facilities design would sustain managing high injection pressure, as in current pilot operation.

Since El Corcobo Norte field is placed in an offsite location, chemicals logistics and transport play a critical role in project operation. Expansion logistics involve supply, transport and storing of almost 8 times pilot polymer consumption. To attend this upscale as efficiently as possible several options are beign analyzed like increasing onsite storage, middle-point storing, freight route modification, etc.

Project Operational Design

For the pilot design injection water is provided to the polymer plant from a water treatment facility that de-oxygenates and filtrates fresh water. The water stream is softened in the polymer plant to remove 200-400 ppm total hardness contained in the water source down to to <5 ppm hardness. This same arrangement is considered for the project expansion, although managed total injection rates would go up to 7700 m3/d in comparison to the < 1000 m3/d handled in the pilot.

In the case of the six injectors of the pilot, injection set up is so that each well has a separate polymer pump, allowing the control of each well's polymer concentration. This resource was eventually used to analyze the behavior of injection pressure vs. polymer concentration, and individually select wells for concentration reduction in times of polymer shortage. Current set up for pilot's facilities are shown in Figures 8a and 8b.

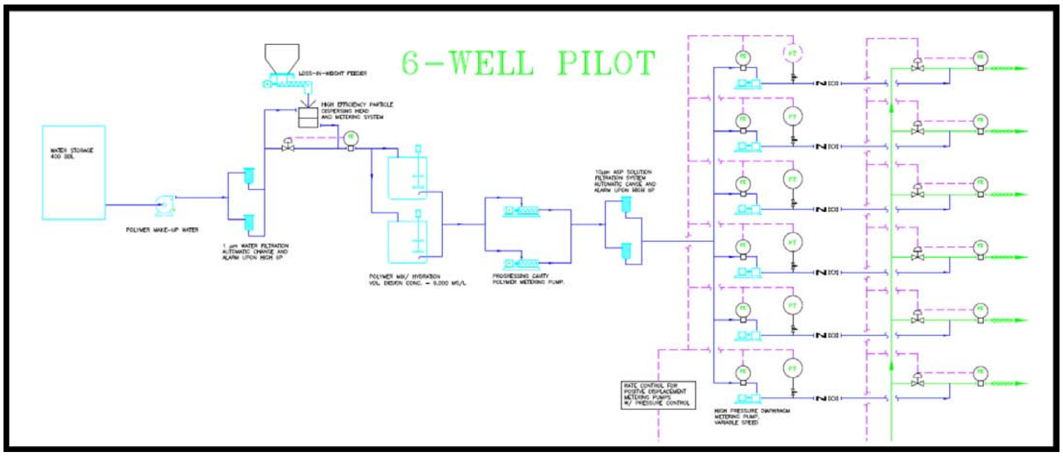


Figure 8a—Pilot's Process Flow Diagram

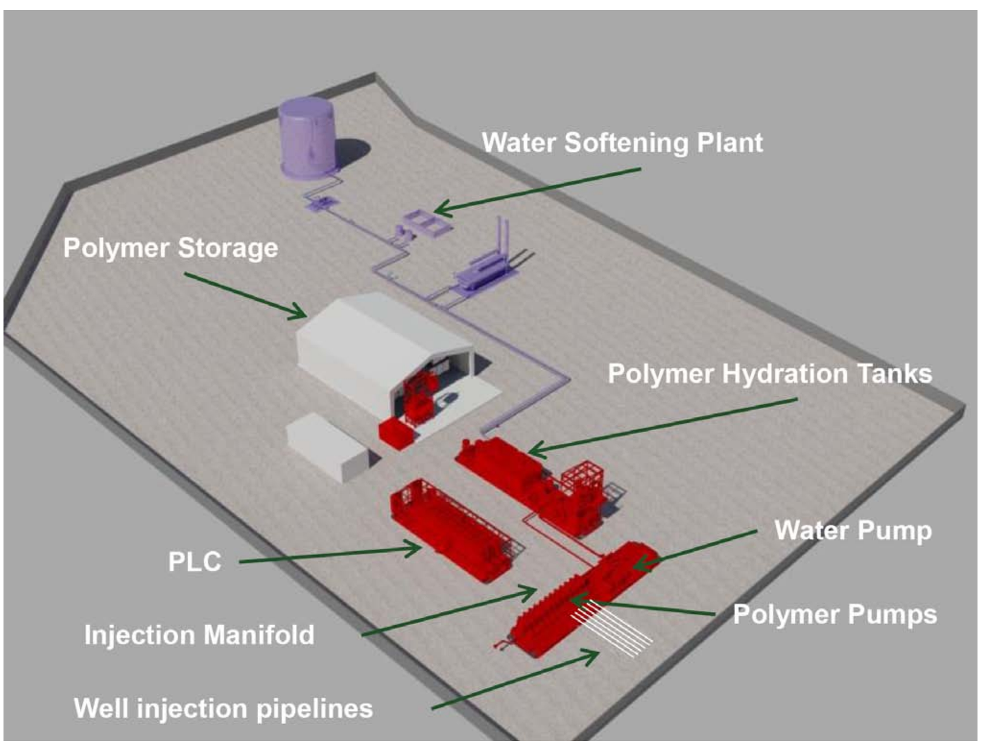


Figure 8b—Pilot Plant Layout

In order to deliver polymer solution to the expansion project the following tasks needed to be addressed regarding facilities:

– Increase fresh water supply to polymer plant and softening:
  New pumps and flowlines to deliver total rate from intake nearby Rio Colorado to polymer plant. Replacement of water softener tanks to process new injection rate

- Increase polymer hydration capacity

  Addition of new polymer maturation tanks that complement existing ones. Upscaled polymer plant is showed in Figure 9.
- High pressure polymer solution deliverability from polymer plant to each injection satellite

  Individual polymer pumps and manifolds to distribute polymer solution at final concentration to each of the involved satellites
- High pressure polymer solution distribution to injector wellheads

  High pressure surface lines from injection manifolds to wellhead

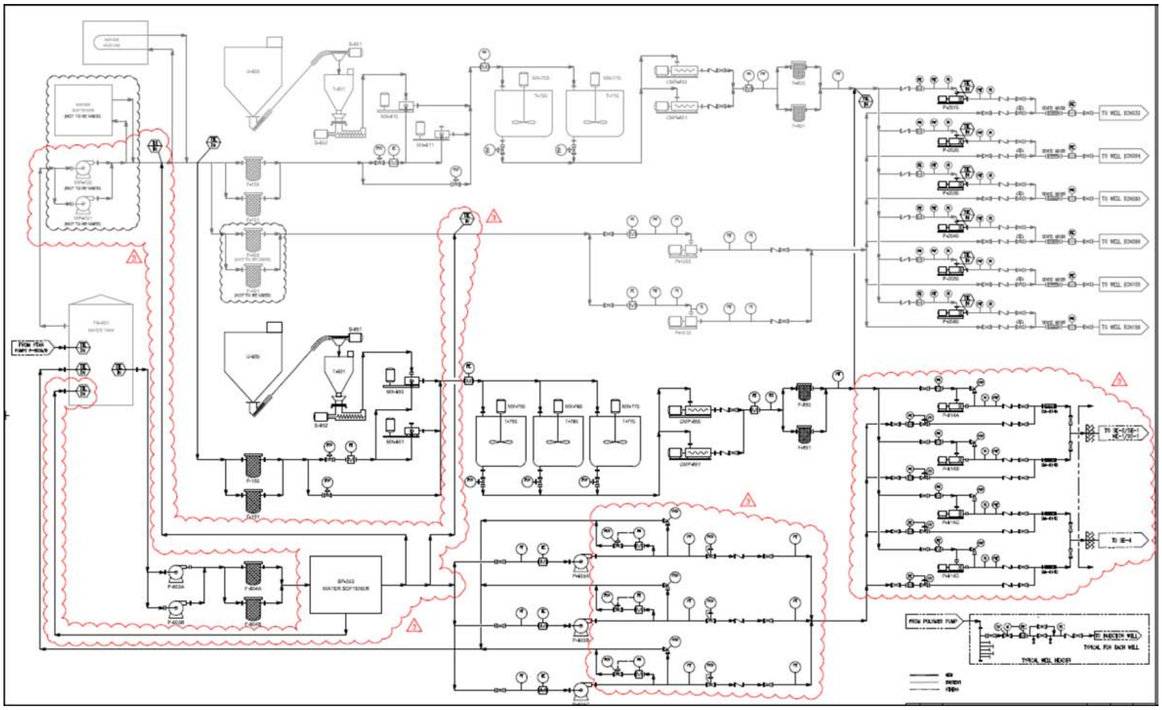


Figure 9—Upscaled Facilities Process Flow Diagram

Polymer solution distribution in the upscaled project applies the same concept as in the pilot, although an injection satellite is now the flow unit instead of an injector well. This design allows operational flexibility on a satellite basis, even though the project design does not contemplate injecting different polymer concentrations to achieve expected recovery. According to lab tests during the pilot design, there's no substantial information to recommend a higher polymer concentration that the one validated in the polymer pilot, since the recovery improvement is marginal in comparison to the cost addition this increase cause (for this reason the pilot validated results at 500 ppm polymer concentration) However, the operator considers that there may be other non captured effects that play a role in field scale that may generate an upside for injecting a higher polymer concentration. Although these effects cannot be simulated with the available tool, there could be an optimization opportunity during the expansion phase in injecting a higher polymer concentration in one of the satellites and evaluate, for instance, a reserves acceleration project. To further investigate this possibility a series of long term injectivity tests are being planned to be performed in the pilot zone, although they won't be covered by the present article.

From the pilot experience injection pressure behavior was one of the most important learnings. Among the pilot injectors, different behavior was observed for injection pressure over time. Some of the wells started polymer injection with zero wellhead pressure (injection restriction had to be applied in order to avoid these wells injecting uncontrolled rate) and gradually started building pressure all the way up to surface pressure limit imposed by the system. Other wells that started polymer injection with a certain pressure also increased it but with a slight increase slope. Updated injection pressure behavior for the pilot is shown in Figures 10a and 10b. As covered by Hryc *et al*., pressure building under polymer injection was expected, and in El Corcobo Norte CHOPS strategy (Cold Heavy Oil Production with Sand) makes injection pressures a very hard-to-predict parameter. This dispersion in pressure behavior is also expected in injector wells involved in the expansion.

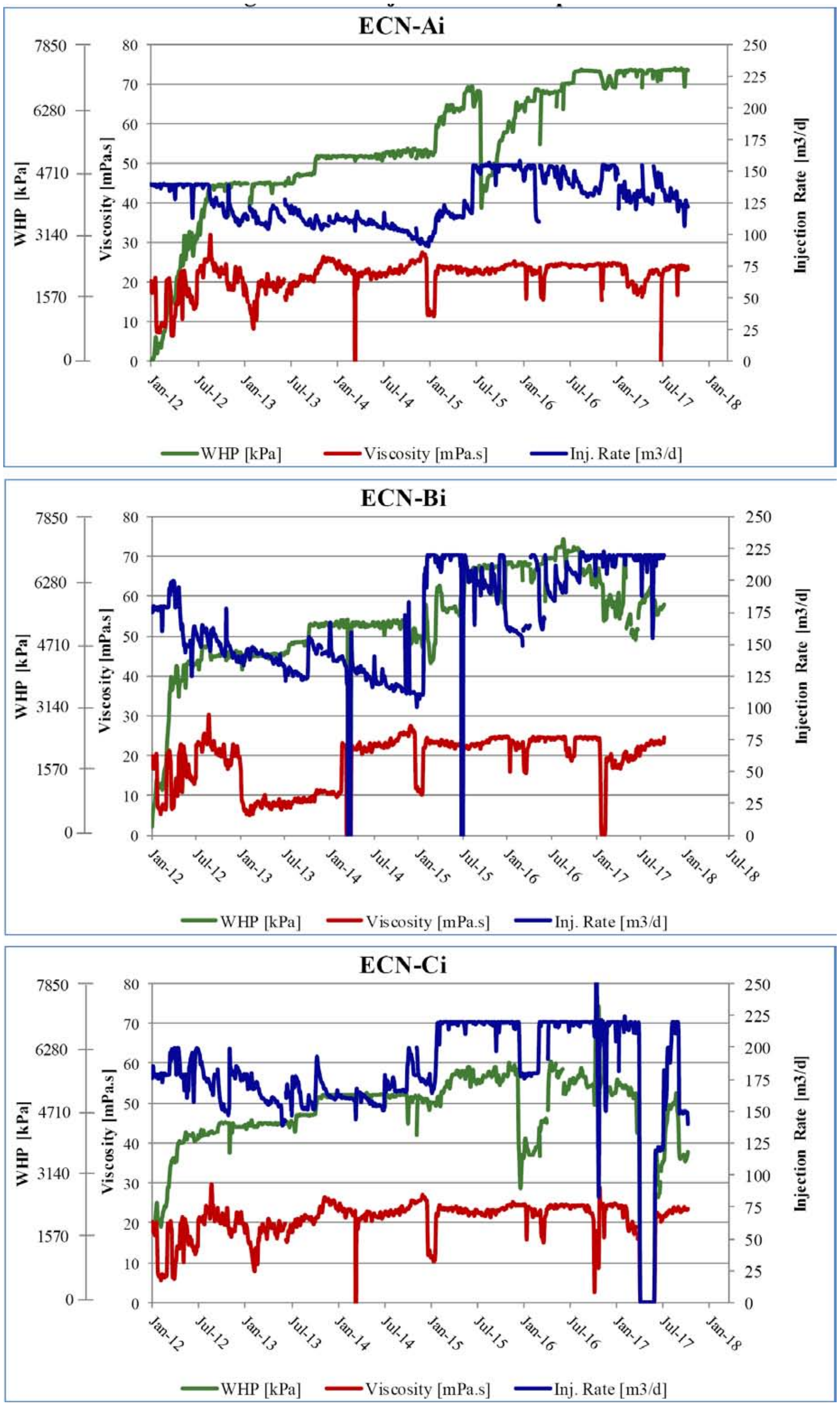


Figure 10a—Injector Well Response

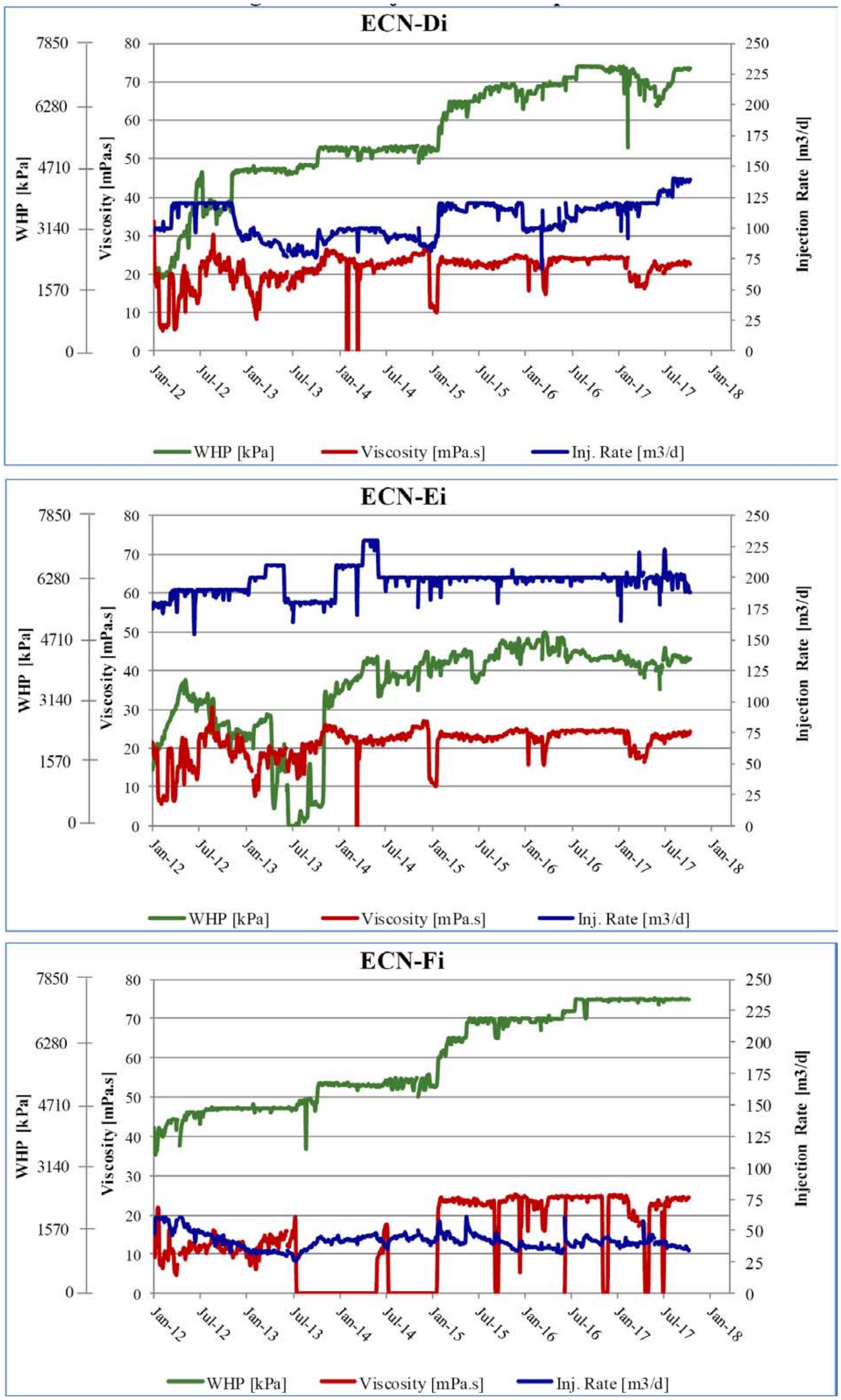


Figure 10b—Injector Well Response

In order to attend injectivity and desired injection rate, the use of curlers was tested in order to give a specific a pressure drop without tempering with the polymer solution properties. Curler device would be installed in the injector surface line, and the length of the curl relates to introduced delta pressure. Figure 11 shows an example of curler type that'd be used to address pressure control. Desired injection daily rate for each well would be controlled by the use of curlers as a first approach, and ultimately restricted if necessary by the use of on-off valves installed in each injection flowline.

Figure 11—Curlers Set Up Example

Project surveillance is proposed to be performed according to a monitor plan that's design considering the pilot's experience. Daily controlled variables, such as water properties and viscosity would continue their control as in the operation of the pilot, although what was controlled on an injector well base, would now be controlled on an injection satellite base. A schedule for wellhead sample viscosity checks and polymer concentration measurements would also be implemented once the expansion is running. A start up operational manual was issued to enlighten in how to start injection at a higher pressure in each of the satellites, pressure handling, operational parameters control, etc.

Regarding production facilities, project fluid rate would be received and treated along with the rest of the field's production (no isolated production facility is required for the upscale). Although polymer presence has proven not to be problematic for water oil separation after 6 years of injection, produced polymer concentration in the pilot zone is currently below 50 ppm. Expected oil response for the project would be monitored according to production allocation in affected wells. Nevertheless the magnitude of the total response should be easily measurable since the upscaled project is not affected by the dilution effect that the pilot showed, having only 2 producer wells totally surrounded by polymer injectors.

Upscaling Main Operational Uncertainties and Risk Mitigation

As previously mentioned, injection pressure behavior is one of the most unpredictable parameters in El Corocobo Norte project. Learnt lesson from the pilot tells injection pressure rise needs to be available in order to sustain constant rate constrain in certain wells. To understand the start point, all injector wells involved in the expansion were relevated and separated into three well groups in the waterflood stage: 1) injectors with zero pressure (restriction needs to be applied), 2) injectors with a certain wellhead pressure during water injection operation, and 3) injectors already operating close to surface pressure limit. This classification was done to know the population of wells that are likely to request a curler device to introduce pressure drop and equilibrate the high pressure system. On-off valves to assure total control on well injectivity would be installed in all injection flowline. Derived from this analysis initial state is that only 60% of the injectors al likely to need curlers installed in their lines. Further tests are being conducted to complement existing information regarding pressure drop - viscosity loss - curler length ratio. Acceptable viscosity loss limit is set in 15% nominal value under reference conditions.

Although water oil separation has proven not to be problematic in the pilot stage, produced concentrations belong to a much diluted process than the expansion phase. In the upscale scenario, project –affected production would blend in the treatment plant with the rest of the field's fluids. Therefore, as far as polymer presence is concerned, whatever amount of polymer is produced in the project would be diluted in a 1 to 5 ratio. Additionally, produced polymer, once blended with other zone's production (higher salinity and hardness), would doubtly cause any operational issue. However, to be on the safe side, special water -oil separation tests are being conducted to analyze best way of treating production with existing facilities as a function of produced polymer concentration. These tests are being design and executed inhouse, combining plant and also lab experiments.

Compatibility with other production chemicals is also being studied for injection polymer solution, specifically the ones used in water plants and biocides used for souring control. Special studies are being performed to find biocide chemistry that protects polymer from degrading in the case it needed to be used in fresh water plant.

Considering described capital expenses and other premises, cash flow analysis was done in order to obtain a net present value distribution by imputing impacting variable distribution curves. As a result of this calculation, upscale project economics show attractive and with a chance < 2% of having negative values.

Summary and Conclusions

A project expansion is being design in light of the results of the polymer pilot results published by Hryc *et al*. SPE 160078 and SPE 181210. The upscale involves an injection rate that goes up to 7000 m3/d polymer solution, affecting 78 injector and 126 producer wells. Expected recovery distribution has a mean of 7 % recovery factor increase over waterflood recovery. Operational design contemplates increasing fresh water supply, polymer hydration capacity and injection solution distribution at high pressure from polymer plant to injector wellhead. Project economics show expansion as attractive and limited risked.

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