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Artificial Lift overview and perspectives for the production of unconventional resources in the Neuquén basin

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Declaration

I PABLO VLADIMIR GRISTO SAVORNIN confirm that this work submitted for assessment is my own and is expressed in my own words. Any uses made within it of the works of other authors in any form (e.g. ideas, equations, figures, text, tables, programs) are properly acknowledged at the point of their use. A list of the references employed is included.

Signed ....

Date 31st March 2017

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Pablo Gristo Savornin.-

Summary

Neuquén basin in Argentina is an emergent producer of oil and gas from shale and tight reservoirs, and further large scale development would require research and field testing of production technologies, to attain a sustainable exploitation of the resources. Artificial lift systems are key production elements considering the rapid declining behaviour of tight and shale wells. Very often unconventional wells exhibit additional challenging conditions: complex downhole configurations, solids' and gas handling issues, and deep targets.

This thesis comprised the review of published experiences and lessons learned in lifting unconventional wells in North America, together with the analysis of specific information from Neuquén shale and tight resources, including the outlook from regional and local experts.

Plunger lift and sucker rod pumps are the preferred systems in Neuquén for lifting shale oil wells after 1 - 1.5 years of natural flow, while lifting methods for deliquification of tight and shale gas wells is a marginal figure.

Under a reasonable growth scenario, it is recommended to pilot test other systems to check field limitations and performance, mitigation and optimization strategies, and to acquire real data to run economic models, providing key information to assess them at the field development planning. All show distinct limitations and challenges, and are feasible to be used under certain operational conditions and during certain periods of the well life, summarized herein.

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1. Aim and Objectives

The aim of this thesis is to review current situation and to explore the future applications of artificial lift systems for the production of unconventional oil and gas resources at the Neuquén basin in Argentina.

Neuquén basin is an emergent producer of oil and gas from shale and tight reservoirs, and further large scale development would require research and field test of production technologies, to attain a sustainable exploitation of the resources. Artificial lift systems are essential to produce at economic flowrates and to achieve higher recovery factors, much more important considering the rapid declining behaviour of tight and shale wells.

The said objectives are intended to be accomplished through the review of published lessons learned and trends in lifting unconventional wells in North America, together with the analysis of specific information from Neuquén shale and tight resources, and the opinion from regional and local experts.

2. Introduction and Literature Review

2.1 Neuquén basin

The Neuquén basin is located in the central western region of Argentina, South America, extending over an area of 120,000 Km2. It exhibits a triangular shape, limited at northeast and southwest margins by ancient cratonic areas, and the Andes Mountains to the west (Figure 1). The sedimentary fill comprise continental and marine sediments, carbonates and evaporites, deposited from Late Triassic to Early Cenozoic. Deposition has been controlled mainly by tectonics and global eustatic changes occurred over the western margin of Gondwana supercontinent, from a Late Triassic to Early Jurassic syn-rift phase, Early Jurassic to Early Cretaceous post-rift and Back-Arc phase, and a Late Cretaceous to Cenozoic Foreland phase (Howell, et al., 2005).

Several tight and shale resources[1] has been identified within the stratigraphic column (Figure 2). Vaca Muerta Fm. is one of the most promising and largest shale gas and oil play identified outside North America (EIA, 2013), and a number of fields are being explored or developed through pilot projects, with recent progress under a 'factory drilling' model (Gomes & Brandt, 2016). Another shale resources include the marine shale of Los Molles Fm. (mainly a gas play, not much producing currently), and possibly in a less extent, the

[1] The terms 'unconventional', 'tight' and 'shale' resources (and reservoirs) as used throughout this thesis are defined at Appendix I.

lacustrine shales of Puerto Kaufman Fm., and the marine shales of Lower and Upper Agrio Fm.

Tight gas accumulations from clastic, igneous and metamorphic rocks have been produced in Neuquén for many years, but only recently some of these plays were comprehensively explored and developed on a larger scale. Tight sands of Lajas Fm., Mulichinco Fm. and Punta Rosada Fm. are currently produced, along with a small contribution of Los Molles Fm. and certain natural fractured intervals of igneous and metamorphic rocks of the Precuyano Cycle and the Basement (Huenufil Molina & Alonso, 2016).

As of October 2016 the governmental oil and gas database (Ministerio de Energía y Minería, 2016), reported 604 active wells for the production of 832 MMscf/D (23.6 million m^3/d) of gas from tight resources, mainly from tight sands of Lajas Fm., Mulichinco Fm., Los Molles Fm., and Punta Rosada Fm. Regarding shale resources, there were 583 shale oil wells and 73 shale gas wells producing 34,200 B/D (5,400 m^3/d) of oil and 184 MMscf/D (5.2 million m^3/d) of dry and associated gas, by far from the Vaca Muerta Fm.

The large scale production of the Neuquén unconventional resources face several technical-economic challenges and it is uncertain how much would progress in the near future (Gomes & Brandt, 2016). Nevertheless, under a reasonable development scenario it would require the optimization of production technology, including artificial lift systems.

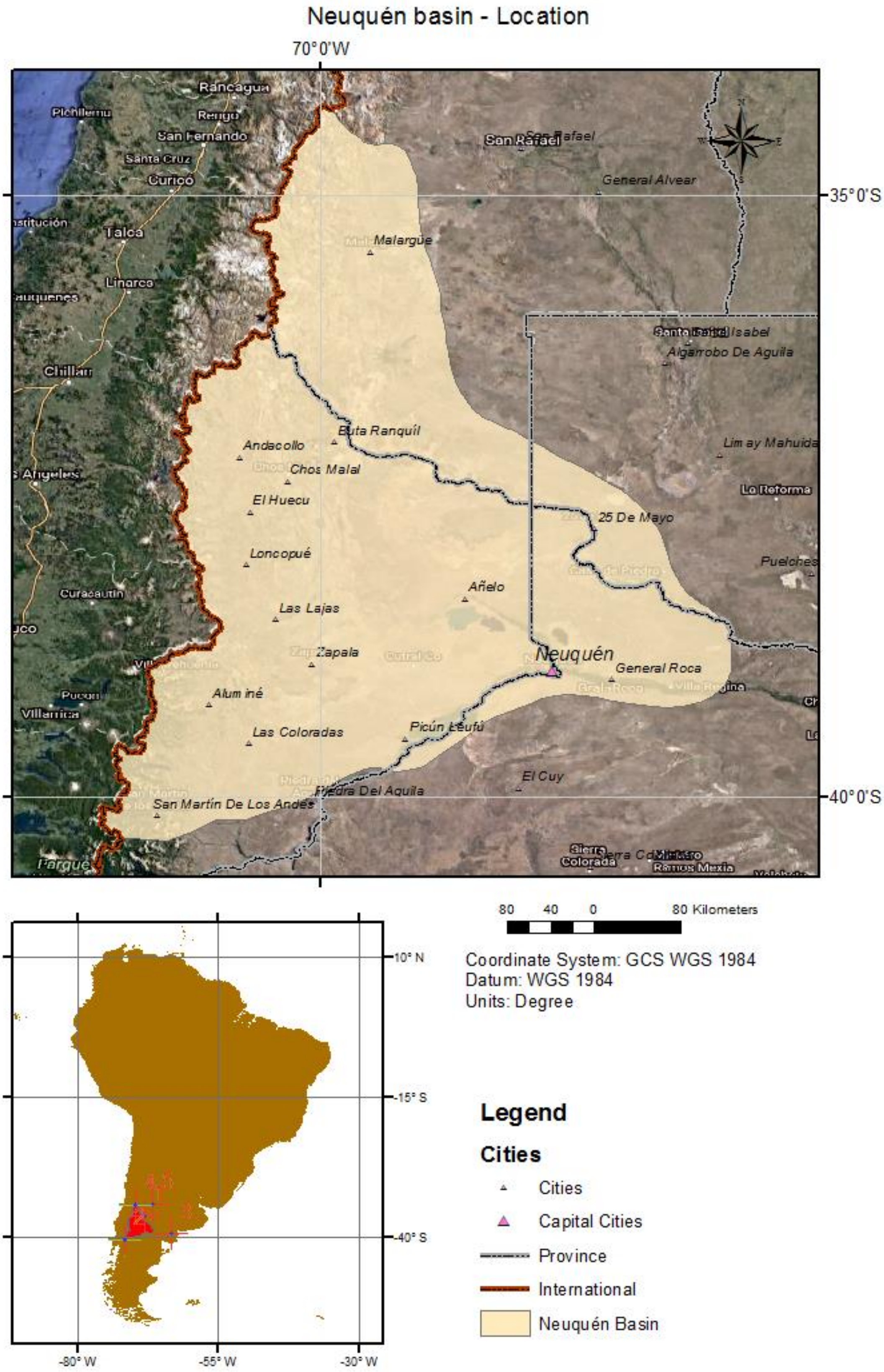

Figure 1: Neuquén basin.

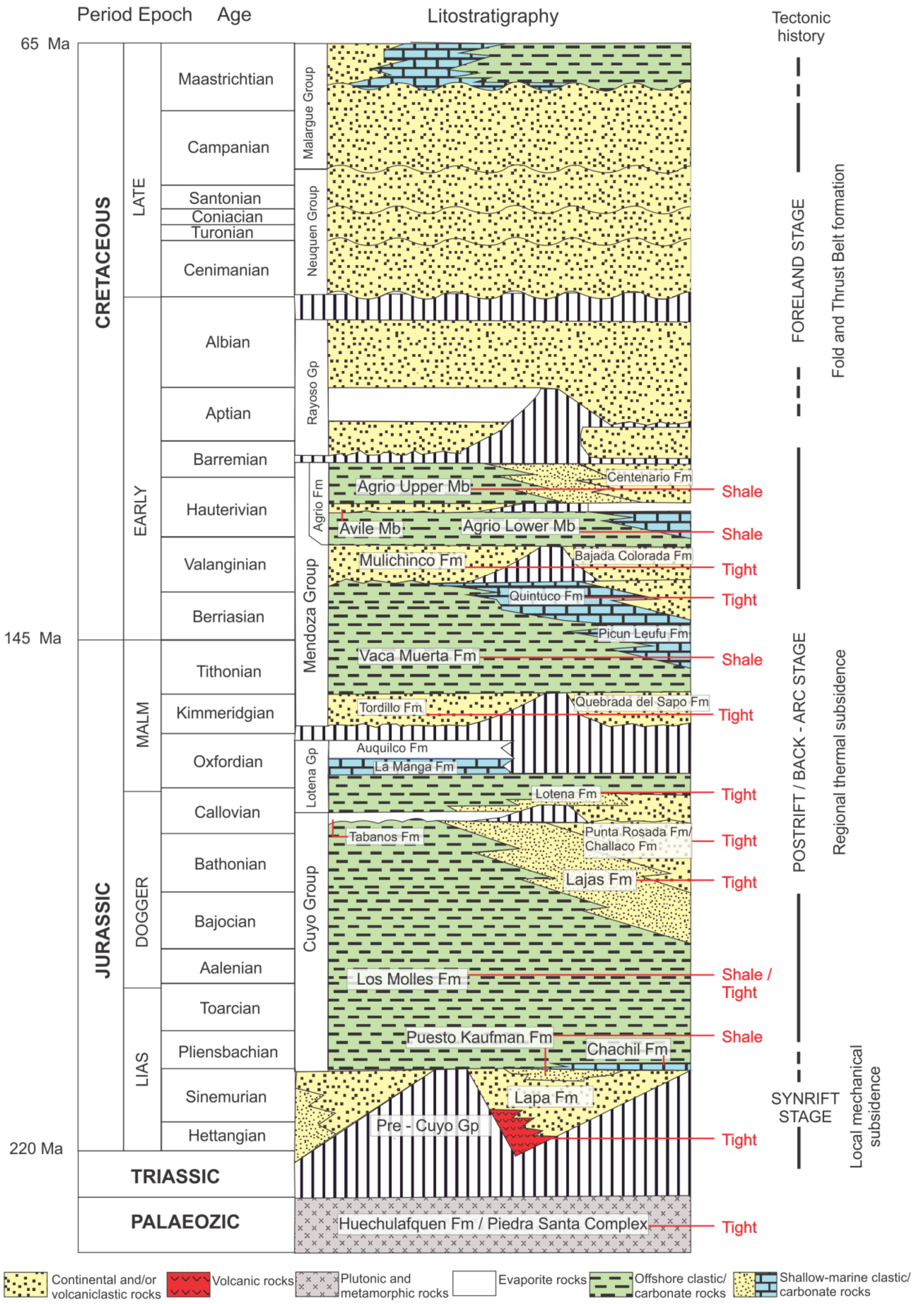

Figure 2: Stratigraphic column of Neuquén basin showing shale and tight intervals, after: Howell, J.A., et al, (2005).

2.2 Artificial Lift Systems for unconventionals

Artificial lift systems[2] are key production technology elements, developed to achieve an economic flowrate from the well and/or a sound recovery of hydrocarbons in place.

The most typical lifting methods and technologies developed for conventional resources are still of use on shale and tight wells. This thesis focus on the following six main systems: Sucker Rod Pump (SRP), Plunger Lift (PL), Gas Lift (GL), Electric Submersible Pump (ESP), Jet Pump (JP) and Progressing Cavity Pump (PCP). The said systems are assessed on a qualitative basis, as of their current and future application on lifting shale and tight wells in Neuquén basin. The following well and reservoir configurations are usually taken into consideration to assess the feasibility of application and expected performance of each system: reservoir (and well) depth, typical well geometry and architecture, production rates through time, and fluid characteristics (i.e.: gas/oil ratio, solids, scaling or paraffin formation).

The importance of selecting an appropriate artificial lift system for unconventional production in North America has been recently emphasized by several authors, and some specific documents have been produced on that regards (Khan, et al., 2014) (Lane & Chokshi, 2014) (Lane & Campbell, 2017) (Miskimins, 2009) (Oyewole, 2016) (Van Sickle, et al., 2015). Specific reference

[2] A description of the basic elements, the operating principles, and the selection process of the main artificial lift systems is included at Appendix III.

and field examples for lifting tight and shale wells have been published concerning the use of sucker rod pump (Orji, et al., 2016), gas lift and jet pump (Nunez Pino, et al., 2016), and plunger lift (Kravits, et al., 2011). Other references provide relevant information for the selection of deliquification systems in unconventional gas wells (ALRDC, 2013) (Oyewole & Lea, 2008) (Rehman, et al., 2011) (Valbuena, et al., 2016). There is fair agreement among the authors about the main challenges associated with lifting unconventional wells:

- Rapid decline production rates, demanding artificial lift earlier in the well life compared to conventional wells. A single flexible system with broader operating envelope would be required, or a series of methods to be installed consecutively as the flowrate and fluid characteristics change. Also, appropriate well completions are required to allocate successive systems, preventing from uneconomic retrieval and installation of downhole equipment.
- Complex well geometry (i.e.: high dog-leg severity and/or horizontal wells with large lateral sections toe up or down) limiting the installation, operation and retrieval of downhole equipment, and introducing complex flow regimes which impair the system performance.
- Production of sand grainsize solids (proppant from hydraulic fracturing) throughout the well life but particularly at early times.
- Other challenging issues: deep targets, and medium to high GOR fluids that require particular gas handling equipment.

The rapid declining behaviour of unconventional wells restricts the alternatives for artificial lifting because each system has a characteristic operational flowrate envelope (the flowrate range at which can work or perform efficiently).

Besides that, each system will perform different at a certain time of the well life, delivering a different reward in production rate. This effect can be sketched on the typical Inflow Performance Relationship (IPR) versus Vertical Lifting Performance (VLP) chart presented by Brown, K. (1982), as shown at Figure 3. Artificial lift acts on the wellbore fluids, allowing a higher drawdown than natural flow by reducing downhole pressure, or wellbore fluids density. Drawdown and the corresponding flowrate will be different for each system, but in the case of unconventional reservoirs, this difference is only significant at very early times of the well life (a more comprehensive discussion is presented at Appendix III).

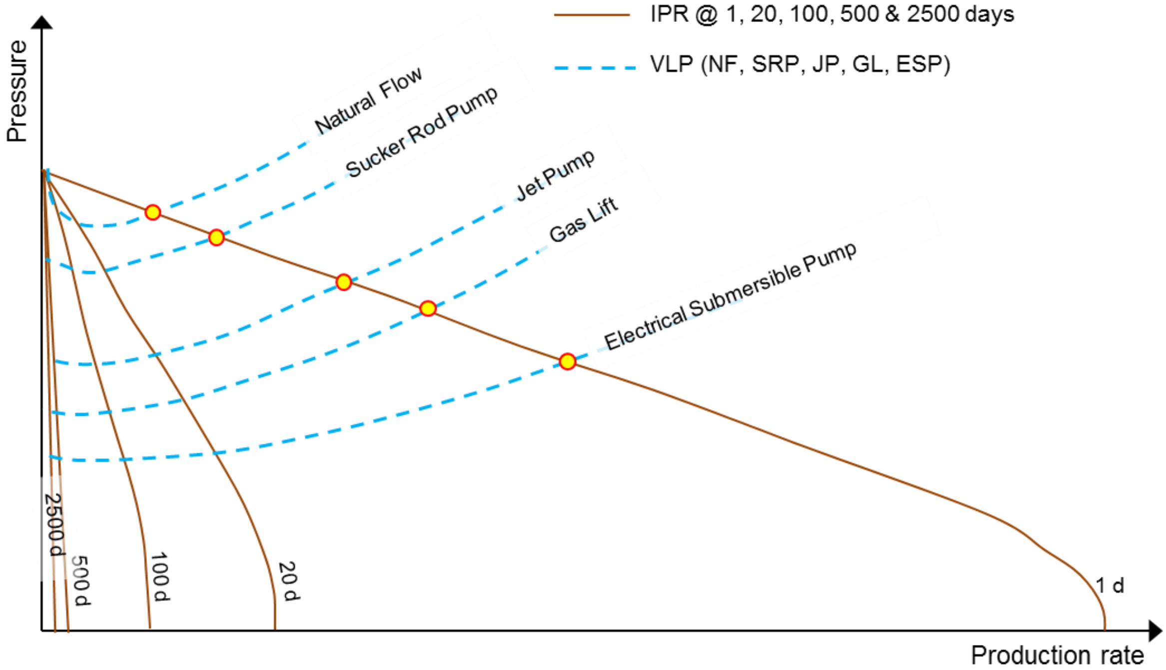

Figure 3: IPR and VLP curves of unconventional wells, after Kahn, N., et al (2014) and Brown, K. (1982).

3. Methods

A comprehensive literature review was conducted to identify the state of the art (technologies, trends, and challenges) of artificial lift applications for the production of unconventional resources. Apart from the usual international technical sources, relevant information can be accessed from industry organizations and the government of Argentina, in particular the governmental oil and gas database (Ministerio de Energía y Minería, 2016). This database, described at Appendix II, discriminates between conventional and unconventional resources (shale or tight), and 9 types of extraction methods (natural or artificial lift) . The data downloaded from this source was compiled and processed to identify production trends and the use of artificial lift.

Additionally, a survey to artificial lift providers in Argentina and the region was performed (Appendix VI). A short questionnaire was sent by email to 14 experts at 8 artificial lift providers, often complemented with a personal discussion by telephone.

A collection of published qualitative and quantitative guidelines and recommendations (ALRDC, 2013) (Brown, 1982) (Clegg, et al., 1993) (Khan, et al., 2014) (Valbuena, et al., 2016) were applied to assess the main artificial lift systems. The assessment was complemented with published case studies and recommendations for lifting unconventional resources in North America, and also in Argentina when available (Martinez, et al., 2015). Main findings were discussed with the experts, in order to achieve a complete picture.

4. Results

A clear understanding of the state of the art of shale and tight resources’ in the Neuquén basin was attained by a thorough review of literature in combination with production data and the information delivered by the experts.

Currently much of the published research and field experience is related to reservoir characterization and modelling, and the optimization of drilling and completion design and operations, with a few examples of artificial lift applications (Martinez, et al., 2015). The former have been identified as the key subjects for the unconventional production optimization, and the core of the unconventional well performance and expenditures.

Based on a development scenario of 9,800 shale and tight wells to be drilled in the period 2017 - 2030 (Appendix V), the estimated expenditures to be required by artificial lift installation and operation is within 3,000 - 7,000 million USD.

A simple approach to the analysis of artificial lift requirements is to split the unconventional well life into four periods with distinct flowrate and fluid properties (Oyewole, 2016) (Khan, et al., 2014) (Lane & Campbell, 2017):

- Flow-back. Right after hydraulic fracturing, injected fluids are allowed to flow back, cleaning up and preparing the reservoir for production. This process can last for days or weeks producing a volume generally smaller than injected (5 to 30%). Apart from fracturing fluids, reservoir fluids (sometimes including formation water mobilized by enhanced permeability) and proppant solids are produced. It is common for certain unconventional reservoirs of North America, for the wells not to surge at flow-back because there’s not enough bottom-hole pressure to lift the fluid column with high water content. Therefore, an unloading operation has to be implemented (i.e.: swabbing or nitrogen lifting), or an artificial lift system installed from the beginning of the well life.

- Natural Flow. After flow-back, If the reservoir energy is enough to lift the wellbore fluids (which still can contain significant amounts of fracture fluids, giving a dense liquid column to lift), then the well will flow naturally. This period will attain the highest flowrate, with a rapid production decline curve for a short period of weeks to months. In many cases in North America, this period is absent, and during or after flow-back, no natural surge is possible because of a combination of fluid and reservoir characteristics (i.e.: high density fluid, low bottom-hole pressure, depth).
- Early Drawdown Period. After natural flow, the well experience a large decline in flowrate and bottomhole pressure; typical unchoked production decline rates of 59 – 81% has been reported for the main shale plays in United States (Lane & Chokshi, 2014). Pressure drop moves the near wellbore region through the bubble point, which would increase the gas/oil ratio (GOR) and cause a detrimental effect into the reservoir drive energy. This is the most challenging period for artificial lift systems in terms of varying flowrates, and sometimes other conditions (i.e.: GOR, bottomhole pressure)..

- Late Drawdown. After a large declination, the flowrate stabilize at a relatively low value, as well as the bottomhole pressure, and the challenge of this period is to enhance fluid recovery at economic flowrates.

A theoretical production curve outlining the former periods, is shown at Figure 4. The need of artificial lift for unconventional production is evident in order to attain a sound recovery from the drainage area (i.e.: to expand well's life, or delay the timing of plug and abandonment 'P&A' of the well).

Considering the large variation in well production characteristics flowrates over well's life, and even over short periods, two strategies for artificial lifting have been applied (Khan, et al., 2014) (Lane & Campbell, 2017): (1) to select a system which can accommodate varying flowrates (high turn-down ratio) by just changing some parameters (i.e.: sucker rod pumps, by changing strokes per minute); or, (2) to plan a high and a low rate system (in 2 steps or more) which can be easily and economically interchangeable.

Figure 5 and Figure 7 show some examples from literature of typical production decline curves of Neuquén shale and tight wells. Although these Neuquén curves would involve quite different well characteristics and production technologies, the general declining shape is very similar to the theoretical curve at Figure 4. Most of the tight and shale wells of Neuquén basin were drilled after 2012, and there is no long term well behaviour information available yet to determine how these wells will produce at the late drawdown period.

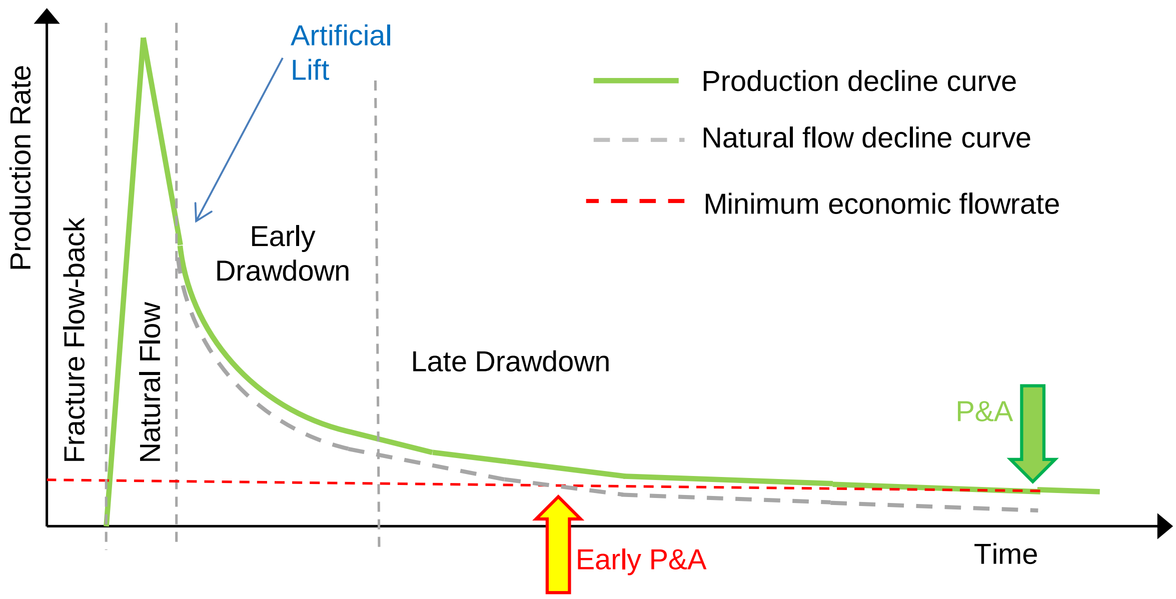

Figure 4: Typical production decline curve of unconventional wells. Modified from Lane, W., & Campbell, S. (2017) and Lane, W. & Chokshi, R. (2014).

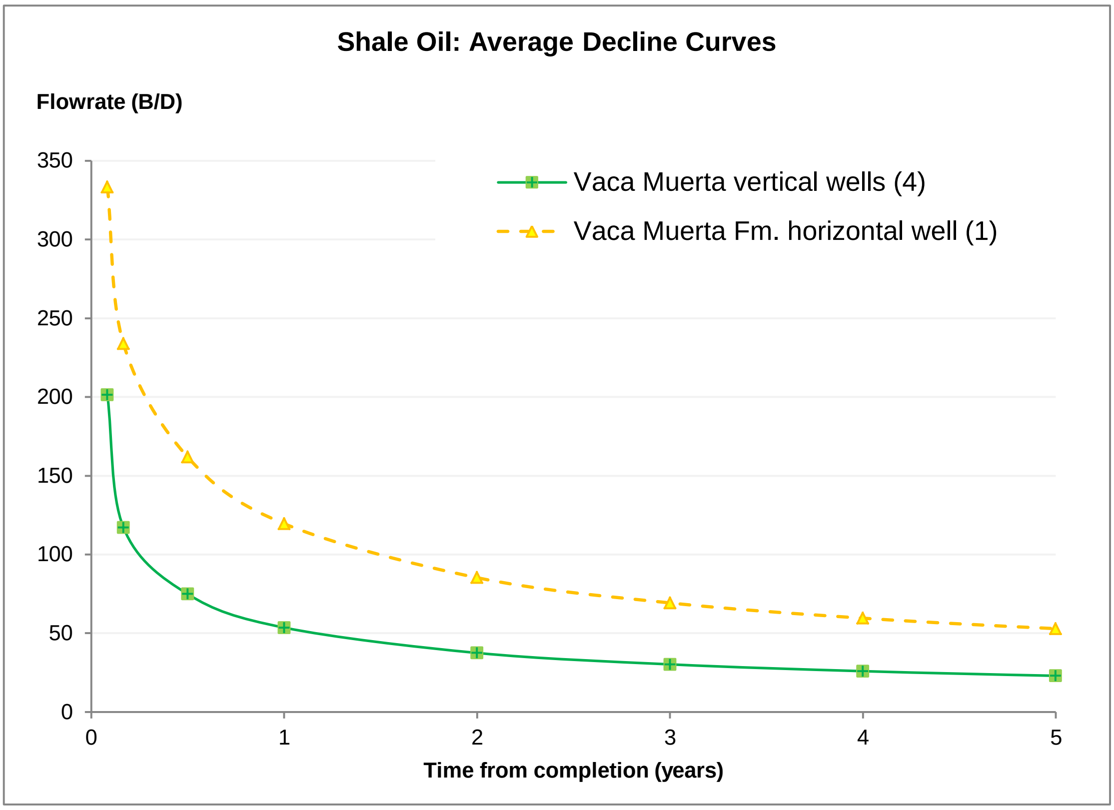

Figure 5: Typical production decline curves for Vaca Muerta Fm. shale oil wells. Modified from Gutierrez Schmidt, N., et al (2013).

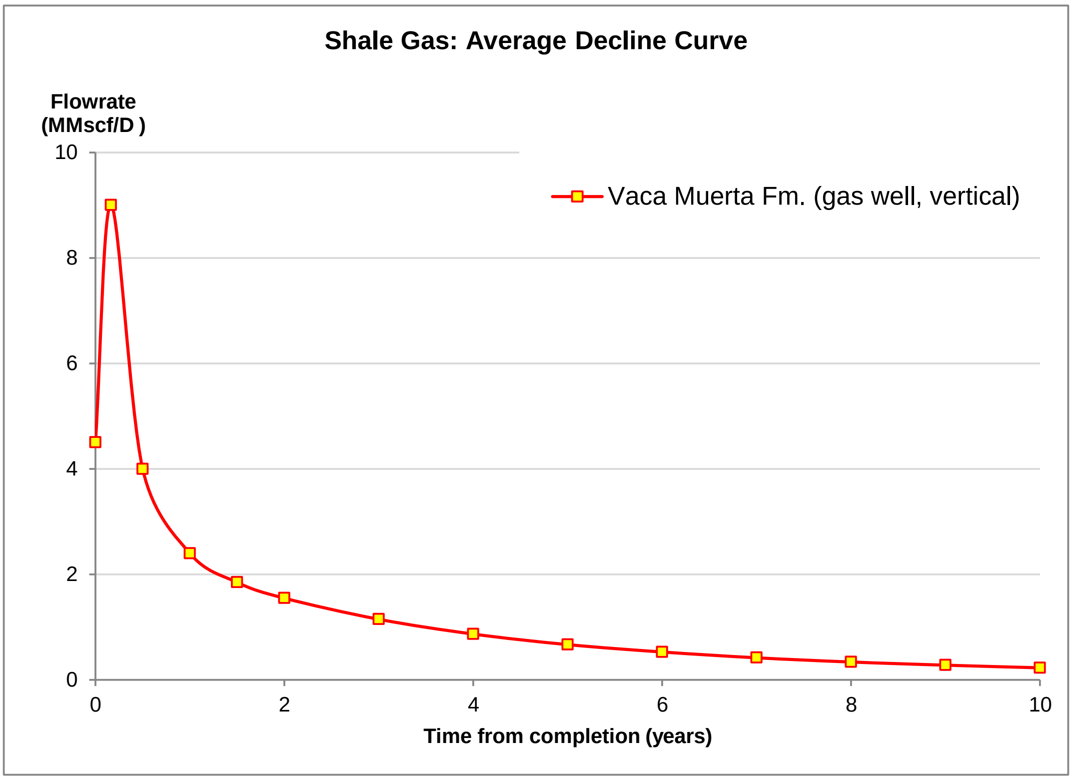

Figure 6: Typical production decline curve for Vaca Muerta Fm. shale gas wells, after: Olmos, S. (2016).

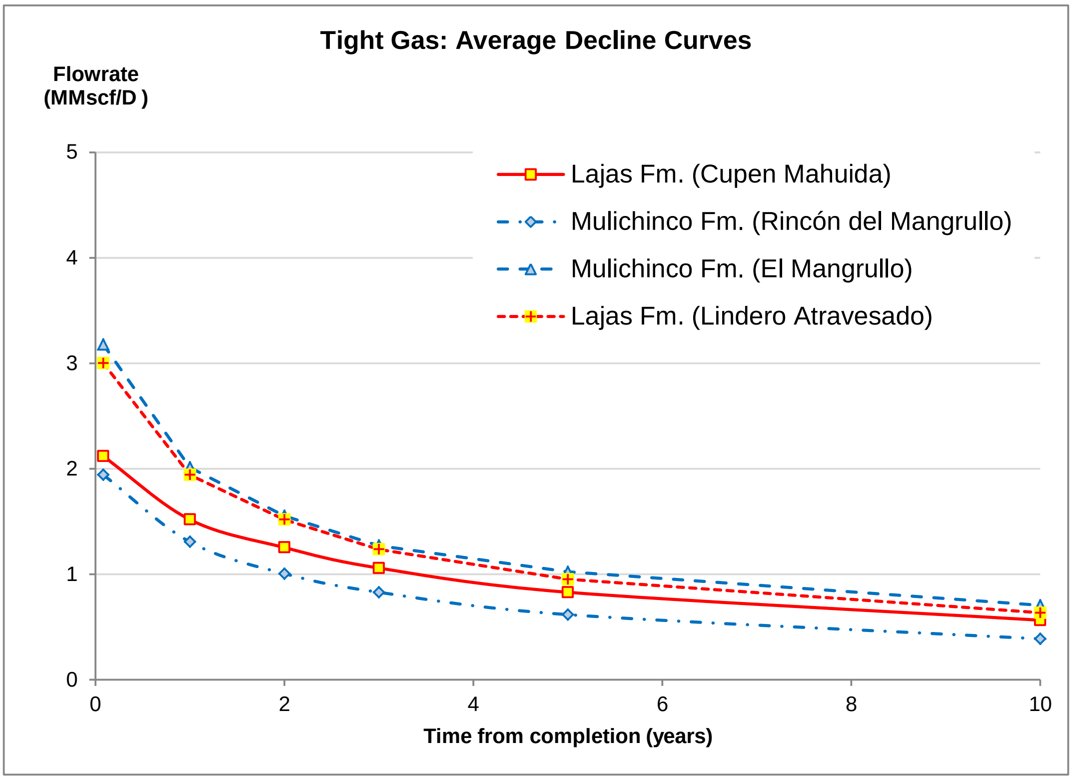

Figure 7: Typical production decline curves for Lajas Fm. and Mulichinco Fm. tight gas wells. Modified from Huenufil Molina, C. & Alonso, M. (2016).

Processing of data from Neuquén basin showed that most of the shale oil wells naturally flow for around 1 – 1.5 years, including the flow-back period. Thereafter, at early drawdown when the decline in production is significant, plunger lift (51% of active shale oil wells) or sucker rod pumps (24%) are installed (Figure 22 at Appendix II), which is consistent with other reported standard practice (Martinez, et al., 2015).

Not any use of artificial lift for flowing back stimulated shale and tight wells of Neuquén basin has been identified in the literature. Flow-back and natural flow proceeds by an optimized choke management plan. It is reported that the selection of the appropriate sequence of choke sizes effectively drain fracturing fluids and remnants of proppant from the fracture and wellbore, preventing from damaging the fracture structure and permeability, while quickly attaining the production of reservoir fluids (Bonapace & Perazzo, 2016) (Wagner, et al., 2016).

Apparently few shale gas wells require deliquification, as plunger lift is a marginal fraction (11% of active shale gas wells) and gas lift operates in just 2 gas wells. A high proportion of shale gas wells report zero liquid production (27%).Other possible causes are that gas wells preserve enough gas flowrate and bottomhole pressure to naturally lift liquids, or using other non-reported deliquification approach. Production reports do not register other unloading and/or deliquification practices and operations (i.e.: foaming, intermittent production, swabbing). A similar situation has been found for deliquification of tight gas wells, exhibiting a negligible proportion of plunger lift assisted wells

(5% of active tight gas wells), and a few less operating with sucker rod pump and gas lift.

In some cases of tight production, it is reported that the flow-back proceeds through production casing with regular monitoring of the fluids at surface. When certain parameters indicate the end of flow-back (salinity, solids) the well is shut-in to install production tubing, and production resumed at around 20 days (Herrero, et al., 2014). A monobore type of completion in tight reservoirs (production through casing) has also been reported, and the flow-back proceeds directly through the production casing (Barbalace, et al., 2014).

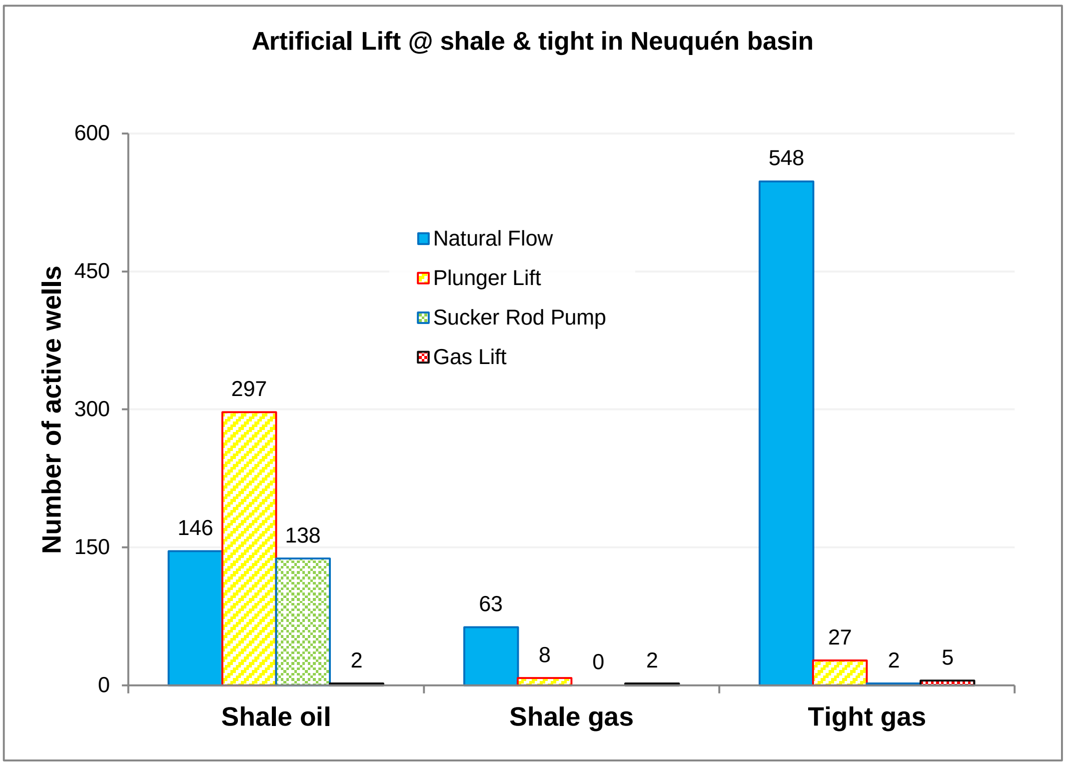

Figure 8: Artificial lift systems installed in tight and shale wells.

Artificial lift is also reported to be installed in shale wells in Neuquén after detecting strong interference from offset wells being stimulated. An increase in water cut (from fracturing fluids), may cease production or strongly reduce productivity of the affected well, which only can be recovered after remedial actions and the installation of artificial lift (with the associated costs from well intervention and deferred production) (Rimedio, et al., 2015).

Considering that gas handling is a problem for most methods, medium to high GOR values found for shale oil wells anticipate it as one of the main key drivers for the selection of lifting systems. At the same time, the large variation in GLR values found for shale and tight gas wells anticipate the feasibility of several deliquification alternatives, in case required.

Neuquén unconventional are generally a deep target for artificial lift applications. This would impact into the method selection, as some of them are seriously limited or even excluded for deep applications (i.e.: PCP).

Not much data is available to assess the current well configuration (geometry and architecture) of shale and tight wells of Neuquén. However, some authors project a higher proportion of horizontal wells in future large scale developments (Gomes & Brandt, 2016), introducing another constraint for lifting systems selection and performance.

Noise level and obtrusiveness of surface equipment would not be a challenge for selecting an artificial system considering the remote location of most of the Neuquén fields, and the large history of production in the basin, despite some particular conditions near sparse urban areas.

5. Discussion

Unconventional resources of Neuquén basin comprise a variety of tight and shale resources, widespread over different structural and stratigraphic settings, and presenting heterogeneous reservoir and fluid properties, even at the field scale. The operators and service companies are progressing on a learning curve, testing production technologies and practices, which are evolving regularly. At the same time, the expansion of unconventional production to other areas, now concentrated in a relatively small number of fields, anticipates a broader range of conditions.

Considering this complex and evolving scenario, it is not possible to apply advanced artificial lift selection tools on a basin scale assessment. In turn, it was possible to assess the main drivers of the selection process to identify the key advantages, disadvantages and challenges of the artificial lift systems.

While much of the research and field experience in Neuquén seems to be allocated on reservoir, drilling and completion (the core of the unconventional well performance and expenditures), an increasing interest on production issues including artificial lift is to be expected. Rapid decline behaviour of tight and shale wells anticipate the need of artificial lift systems to attain sound recoveries and sustainable production models.

The large experience and lessons learned of unconventional production in North America could be replicated in Neuquén basin, taking advantage of the particular lifting technologies and practices that have been developed and proved successfully. However, this knowledge transference would require a careful assessment of the particular conditions, including the commercial and political framework. Testing of the selected artificial lift alternatives through in situ field experience will finally provide the required information to determine the best lifting solutions, something that currently can be performed only theoretically.

Artificial lift sector is estimated to represent a minor fraction of the overall expenditures to be allocated on shale and tight development in Neuquén basin, but still a large amount in absolute terms. Nevertheless, a significant economic impact is expected by artificial lift in attaining larger recovery factors from those resources.

The results from the assessment of the main six artificial lift systems, as for their application in tight and shale wells in Neuquén basin, were compiled as follows.

Sucker rod pump (SRP)

Some advantages like the high flexibility in flowrate makes SRP a natural candidate and standard solution to accommodate the declining behaviour of unconventionals. It can be performed by adjusting the strokes per minute (within specified limitations), or the stroke length (would require an intervention into the unit) (Brown, 1982) (Clegg, et al., 1993).

Wear and fatigue of the rod string and/with tubing is a key challenge in deep wells with a complex geometry. A reduction in failure frequency from this source by using continuous rods (no couplings that increase the friction with the tubing), manufactured in higher strength materials, have been reported recently in Argentina (Lane & Campbell, 2017). Higher strength rods are also recommended to withstand high cyclic loads associated with deep and high rate wells (Orji, et al., 2016). The use of rod centralizers has reduced the wear in deviated wells in Vaca Muerta Fm. (Martinez, et al., 2015). Relatively high-dog leg severity in the Bakken shale wells in United States is commonly mitigated by using rod guides to minimize the effect of wear and high side loads on the rods, couplings and tubing (Orji, et al., 2016). Larger sucker rod units would be required to deliver higher horsepower to lift the rods (Brown, 1982), together with lighter rod materials.

Gas content in the produced fluids can create gas interference or even lock the pump. Mitigation strategies includes the usual installation of gas anchors, and the use of long stroke units which lead to higher compression of the fluids at the pump. This kind of units produce the same volumes with a fewer strokes, reducing the system fatigue and anticipating an increased life of all components. There are rig-less technologies (i.e. insertable pumps) which reduce capital expenditures on deployment (Lane & Campbell, 2017).

The system has limited capabilities to produce sand laden fluids, although there are several special filters and sand exclusion devices available (ALRDC, 2013). Some pumps are designed to either exclude the sand or continue to operate as the sand travels through the barrel-plunger clearance. A moderate abrasion from proppant production has been managed by the use of tungsten carbide valves (Martinez, et al., 2015).

Intermittent production (i.e.: when the low matrix permeability begins to control the flow to the wellbore) is another source of inefficient functioning, and even breakdown of the pump, for which prevention the use of pump-off controllers has been reported (Martinez, et al., 2015). A pump-off controller will stop pumping temporarily the well, to allow fluid entry into the casing-tubing annulus over the pump before automatically restarting, avoiding incomplete filling of the pump (ALRDC, 2013). The use of automation together with an appropriate programming of pumping and shut-in cycles, have registered increasing production from intermittent shale oil wells (Martinez, et al., 2015).

Optimization of the operational parameters (i.e.: pump speed) using field data and running calibrated nodal analysis is also advised (Orji, et al., 2016).

Poor ability to handle solids and medium flowrate upper limit (Clegg, et al., 1993), controvert the SRP to be used during flow-back or early drawdown. However, considering that most of the shale wells in North America end up their mid to late life of production lifted by this system (Lane & Campbell, 2017), it may convert into the preferred system for late drawdown in Neuquén, as far as it significant drawbacks are adequately managed for an efficient operation.

Plunger Lift (PL)

Low initial investment (including rig-less installation) and low operating, repair and maintenance cost, make plunger lift an attractive alternative when enough reservoir pressure is present, and a preferred candidate for deliquification (ALRDC, 2013).

Maximum attainable liquid rate depends on well and reservoir conditions, but certainly it is a low-liquid rate and high GLR system (35 to 200 B/D reported)

(ALRDC, 2013), excluding it from flow-back and early drawdown periods (high flowrates, risk of proppant sticking the plunger).

It is reported as a common system for deliquification of horizontal gas wells in Marcellus shale, after some time of producing through the casing and then through tubing on natural flow, as far as the appropriate plunger type is selected (Kravits, et al., 2011). Higher deviation from the vertical means less ability for wireline retrieval or setting, and higher dog-leg severity would require shorter plungers to prevent from sticking.

Can be applied in cases were other alternatives fail to manage paraffin, salt and/or scale deposition. Special plunger designs (bar stock or padded) are recommended to account for paraffin deposition, despite the increase in energy loss through friction with tubing and impairment of lifting performance (ALRDC, 2013).

Require a uniform pathway for the plunger to travel, which can be solved by selecting plungers that accommodate to slightly varying inner diameter, or by installing 2 stage systems (tapered tubing), however impacting negatively on the performance. Larger tubing diameters would also require special care on the system selection.

Installation of a multi-stage plunger system 2 years after natural flow, showed a significant increment of the oil production in Vaca Muerta Fm. wells, even below lowest GLR limit for plungers to operate efficiently, and also proved beneficial in keeping the tubing free of paraffin (Martinez, et al., 2015).

Recent experience in Neuquén basin revealed that plunger lift is a candidate from early to late drawdown period, in particular for producing high enough GLR wells. However, no information is yet available for long term performance, once the reservoir energy has dropped below the required pressure to efficiently activate the plunger.

Gas Lift (GL)

Being highly tolerant to solids and gas has been reported as a common lifting system both for flow-back and long term operation (Lane & Campbell, 2017) (Nunez Pino, et al., 2016). It also shows good flexibility to accommodate varying flowrates by adjusting the gas injection parameters. However, it would exhibit limited capabilities for low and/or intermittent rates because of unstable flow regimes (heading and slippage) caused by a higher proportion of gas in the wellbore (Clegg, et al., 1993). Well geometry is not an issue of concern, as downhole equipment can be installed or retrieved from horizontal or highly deviated wells through wireline operations.

Large volumes of produced water in the tubing (at flow-back or for whatever reason), would prevent the system to unload the well, even at the highest gas injection pressure and rates. Hybrid systems has been proposed and verified by combining an easy deployable/ retrievable jet pump together with a GL installation, on an appropriate tubing configuration, in order to operate under these conditions (Nunez Pino, et al., 2016).

Gas injection may aggravate existing paraffin deposition problems (Clegg, et al., 1993), what would be of concern for certain areas of Vaca Muerta Fm. oil production.

Regional and local providers showed somehow reluctant to GL application in Neuquén basin, associated with the expected large investment in surface facilities, the increased complexity of operations, and the operational expenditures. Similar initial perception, later on reversed with field experience, has been reported for the Permian basin in United States (Oyewole, 2016). The solution overall cost would be comparable to other systems, as long as it is implemented for a large number of wells (Clegg, et al., 1993). Therefore, it is still a valid alternative to be implemented on a large field scale, at the early drawdown period, under over-ground favourable conditions and fluid characteristics, and when complex geometry wells are expected.

Electric submersible pump (ESP)

High oil prices would favour the selection of the system in order to attain the highest drawdowns, and to deliver record production rates from shale and tight wells (Oyewole, 2016). However, solids' and gas handling issues are still a challenge, for which the industry has developed or improved and extended it typical operational limits.

Proppant has a high potential for abrasion of the ESP, which can be managed by reducing if content before the intake: installation of screen or desander (including a decanter) bellow the pump, filter screens at the pump intake, or using compression pumps. It can be mitigated by the use of improved wear-resistant materials, albeit at higher costs (i.e.: coated or surface hardened stages, abrasion resistant sleeves).

There are some alternatives for enhancing gas handling capabilities: improvements on gas separator and handler devices, the use of tandem gas separator (lower stages can handle higher gas content), to use multi-phase pumps, or vortex stage pumps, or a mixture of the above. The use of variable speed controllers also has been referenced as a good practice to get rid from gas-locking situations. Though, it has been advised that selecting the system only for low GLR wells would be the best approach (Oyewole, 2016).

Energy efficiency could be impaired at lower flowrates, increasing the operating costs of the system (Clegg, et al., 1993). Additionally, the pumps usually run at a fixed speed, then showing poor flexibility for adjusting to declining production. Very few Neuquén shale oil wells currently exceed the minimum flowrate for the lowest rated ESP in the market (around 150 B/D, but extreme applications have reached 1/3 of that). Same assumption would be made for deliquification of shale and tight gas.

The pumps can be installed/ retrieved from wells up to a certain conduit tortuosity, landing the unit such that the housing is not bent (ALRDC, 2013). Smaller casing size would rule out the method, because of the larger motors and pumps required with a slim outline (Clegg, et al., 1993). However, new technologies would comply with smaller casings, and a dog-leg severity up to 25°/100 ft (generally less than 10°/100 ft).

The relatively high cost of intervention (pulling with a rig) prevents from using ESP when a high failure frequency or short-time replacement is expected. Nevertheless, still would be a valid alternative for higher productivity wells (i.e.: horizontal wells with optimized stimulation), at early drawdown period, as far as adequate solids' and gas handling equipment and practices are achieved.

Jet pump

It is a recommended system for wells were assisted flow-back is required or advisable, being tolerant to solids' production. It can accommodate both high high initial and declining production rates by adjusting power fluid rate and pressure (Clegg, et al., 1993). The last two years the system has been used more frequently as a long term solution for unconventional wells in North America (Lane & Campbell, 2017) (Oyewole, 2016). On the other side, the relatively small well drawdown capability would be the biggest setback of jet pumps, which would impact on productivity of the well.

Crooked and deviated holes do not impose a major restriction to the system, as short jet pumps can pass through dog-leg severities up to 24°/100 ft in slim holes (Clegg, et al., 1993). Can lift deep wells, but long and smaller tubing may anticipate unacceptable friction losses to the power fluid.

Other main drawbacks are energy inefficiency, and the requirement of separation and pumping infrastructure at surface (Clegg, et al., 1993). Expenditures from surface facilities can be reduced when field scale solutions are conceived at the development planning stage (i.e.: central boosting battery supplying multiple wells at a pad location, or more efficient surface boosting facilities) (Oyewole, 2016). Wireline retrievable jet pumps offer an affordable alternative to other systems that consume rig time at maintenance. Gas handling is not such a problem for jet pumps as it is for other lifting methods, but free gas reduces efficiency (would also help lift), which can be mitigated by using gas anchors (Clegg, et al., 1993).

Few field experiences with JP in Argentina anticipate some initial reluctance to it implementation. Under current standard practices, no artificial lift would be required for the flow-back period where jet pumps show the solids' handling advantage. Nevertheless, the broader operational envelopes of the system (i.e.: gas, solids, flexibility), make it an exciting alternative to be tested in Neuquén.

Progressing cavity pump (PCP)

Much of the reviewed literature is with regards to deep shale plays in the United States, with metrics exceeding typical depth limits of PCP, hence no extended use of the system for unconventional wells has been identified. Similar depths can be found in Neuquén basin, with a few reservoirs (i.e.: tight sands of Mulichinco Fm.) less than 6,500 ft depth (2,000 m).

A modification to the traditional PCP is the ESP-PCP system or downhole motor driven PCP, instead of a prime mover at surface which rotates the rod string. This system can attain larger depths, up to 7,850 ft (2,400 m) (Khan, et al., 2014).

Other constraints, like the typical small casing and tubing sizes, and high GLR, apart from other potential problems associated with the method (oil/elastomer compatibility, temperature, well geometry), would also limit it application. Although the pumps do not gas lock, may experience reduced efficiency in the presence of gas, and excessive GLR through the pump for extended periods of time can damage the elastomer (ALRDC, 2013).

Having the highest energy efficiency of lifting systems, relatively tolerant to solids, and having fair flowrate flexibility by changing rotor speed (ALRDC, 2013), may persuade operators in the future to carry out field tests and check performance for flow-back and early drawdown periods of the well, on certain shallow to medium depth unconventional targets.

6. Conclusions

The following conclusions can be drawn from the analysis presented in this thesis:

- Neuquén basin in Argentina holds a variety of tight and shale resources, having progressed from exploration to pilot development projects. Under favourable conditions, it is reasonable to expect a significant expansion of the unconventional production in Neuquén the next decade.

- Artificial lift systems would represent a minor contribution to overall expenditures in unconventional development and production, though are fundamental to attain a sound recovery of hydrocarbons in place.

- Lifting unconventional wells in North America confront characteristic challenges: rapid decline rates, complex well configuration and solid handling issues. Sometimes also can exhibit additional challenging conditions for artificial lift systems, like deep targets and gas handling issues. It seems that shale, and in a lesser extent, tight gas wells in Neuquén basin show similar production behaviour and challenges

- All the main six artificial lift systems show distinct limitations and challenges, and are feasible to be used in producing Neuquén basin unconventionals, under certain operational conditions and during certain periods of the well life.

- The selection of the optimal method would require analysis of it performance under specific well and field conditions, including an economic assessment of the capital and operational expenditures and production enhancement from each system. At the time of large field development planning, integration of artificial lift systems to the well and facilities design would provide a much broader range of alternatives to select.

- It is advisable to pilot test other artificial lift systems than currently in place (mostly plunger lift and sucker rod pumps). This will allow checking limitations and field performance, testing mitigation and optimization strategies, and acquiring real data to run economic models.

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Appendix I: Geology of Neuquén unconventional resources

The aim of this Appendix is to provide a summary of the geology of Neuquén basin, with a particular emphasis into the tight and shale intervals.

I.1 Definitions

Throughout this thesis, frequent reference is made to the terms ‘unconventional’ ‘shale’ and ‘tight’ (resources or reservoirs). Sometimes these terms are used ambiguously within the technical literature and the industry; therefore it is convenient to define them as follows.

Unconventional reservoirs (and resources)

Defined in opposition to conventional reservoirs (accumulation of hydrocarbons within a porous and permeable rock), broadly include those type of hydrocarbon accumulations that requires specialized extraction and recovery technologies for producing at economic flowrates and/or to recover economic volumes of resources in place. Within this thesis, the term will be restricted to very low permeability reservoirs (tight reservoirs, including the particular case of shale reservoirs), notwithstanding other type of non-conventional resources, currently producing (coalbed methane, oil shales, oil sands) or potentially productive worldwide (gas hydrates).

The said non-conventional technologies regards basically to well configuration and reservoir stimulation:

- Production through highly deviated and/or horizontal wells, with large lateral sections that navigate through the reservoir to attain a larger drainage area. Several wells are usually drilled and completed from a single location (well pad) to optimize rig and other services' mobilization, and an intensive drilling and completion strategy, termed 'drilling factory' model, is usually applied at the field development stage.
- Stimulation of the reservoir through massive hydraulic fracturing created in several stages, involving the injection of relatively large amounts of fluids with controlled rheological properties and proppant (particulate of sand grainsize which occupies the fracture space creating a structure with higher permeability).

Tight reservoirs (and resources)

A tight reservoir is a very low permeability rock containing hydrocarbons (a regular value of less than 0.1 mD is used as reference), for which no conventional production technology achieve economically feasible flowrates and/or volumes, and hence massive hydraulic fracturing and/or directional wells are necessary (Holditch, 2006). This type of reservoirs comprises different lithologies: sandstones, carbonates, shales and even altered and/or fractured igneous and metamorphic rocks, with hydrocarbon trapped into poorly interconnected porous and/or fractures. The classical models for the production of conventional reservoirs does not satisfactory fit for unconventionals, hence exhibiting increasing effect of capillary forces and different trapping mechanism in the micro and macro scale.

Shale reservoirs (and resources)

A shale reservoir is a particular case of the latter, in which the source rock (fine grained marine or terrestrial rock with high organic content, and variable content of clay, carbonate and silica) has generated and trapped hydrocarbons within the matrix. Most references allocate an even lower permeability range for shale reservoirs (0.001 mD or less) than overall tight reservoirs.

The production of tight gas reservoirs in United States started in the 1970s, when governmental tax credits launched the required investment and technological developments for it production (Holditch, 2006). However, just around mid-2000s, the economic and technical conditions were favourable for the tight and shale revolution in North America, giving to the production of large volumes at reasonable costs, thereafter contributing to a high proportion of the oil and gas internal supplies (EIA, 2013). The exploration-production life cycle for unconventionals in North America advanced from the exploration and appraisal to the implementation of pilot projects, in order to characterize the reservoir performance applying different drilling, completion and production approach, and identifying and selecting the ‘sweet-spots’ (i.e.: most favourable areas for production). These sweet spots were then developed under a ‘drilling factory’ model (Gomes & Brandt, 2016).

Notwithstanding the large volumes of unconventional oil and gas resources assessed in the world, their development faces several technical-economic challenges: the relatively high cost of drilling and completion, the low recovery factor and productivity per well, and the longer term from exploration to production (Gomes & Brandt, 2016). Furthermore, other ‘above-ground’ settings, including fiscal environment, social and political issues, and infrastructure and services’ availability, have a great impact into the feasibility of developing unconventional resources. Therefore, it is still uncertain how and when the large volumes of tight and shale resources identified outside North America, including those of the Neuquén basin, will be developed in the near future.

I.2 Structural and Stratigraphic Geology

Three main mega sequences have been recognized in the evolution of the Neuquén basin, sketched at Figure 9.

Late Triassic to Early Jurassic: syn-Rift phase.

On the western margin of the Gondwana supercontinent, extensional tectonics over the Palaeozoic sequence and earlier basement rocks of the basin, led to a series of narrow isolated half-grabens with NW-SE direction. A complex arrangement of continental clastic and volcanoclastic sediments deposited in these depocentres, grading from alluvial fans to restricted lacustrine environments, comprise the first sedimentary record of the basin grouped into the Precuyano Cycle (Carbone, et al., 2011). Localized organic-rich shales deposited within lacustrine environments of restricted circulation, identified as the Puesto Kaufman Fm., conform the oldest source rock of the basin and a potential shale gas resource (Uliana, et al., 2014).

Early Jurassic to Early Cretaceous: post-Rift and Back-Arc phase.

This phase comprises a complex series of transgressive and regressive cycles, localized uplift, and eustatic sea level oscillations, leading to more than 4,000 m of sedimentary fill. It is recognized the development of a steeply dipping active subduction zone, and the evolution of an associated magmatic arc along the western margin. This phase begins with the first marine ingression into the basin from the western margin, which deposited marine to fluvial sediments of the Cuyo Group during the Early and Mid-Jurassic, comprising the last instances of the syn-rift stage, and the beginning of the regional thermal subsidence (Arregui, et al., 2011). The Cuyo Group includes the organic-rich marine shales of Los Molles Fm., deposited during the climax of the marine transgression, the shallow marine to fluvial and deltaic sandstones of Lajas Fm., the fluvial and alluvial sandstones and conglomerates of Punta Rosada Fm., all of them relevant as unconventional reservoirs. A complete cycle of tectonic induced regression, marine transgression and normal regression occurred between Mid and Late Jurassic, comprising the Lotena Group, constituted by coarse siliciclastics at the base to carbonates and evaporites at the top. In the Late Jurassic, the rise and migration of the volcanic arc closed the connection with the proto-Pacific ocean and established the conditions for the deposition of alluvial fans, fluvial, eolian, and lacustrine and shore-face sediments of the Tordillo Fm. and its equivalents (Spalletti, et al., 2011). These sediments lay unconformably over the Lotena Group. Around Late Jurassic, a generalized marine transgression deposits the main source rock interval of the basin, the organic-rich marine shales of Vaca Muerta Fm., which extends until Early Cretaceous (Leanza, et al., 2011). It is overlaid by Quintuco Fm., another unit with unconventional interest, consisting of proximal sediments and terminal members of this transgression event. A major, tectonically-induced sea-level fall occurred in the Early Cretaceous that deposited continental, transitional and open marine sediments grouped on the Mulichinco Fm. (Schwarz, et al., 2011). This is a recognized conventional and tight reservoir unit. At the top of these sediments, the lower and the upper members of the Agrio Fm. were deposited (Spalletti, et al., 2011), consisting of mid-Cretaceous marine sediments. These potential shale oil and gas reservoirs were deposited under a mixed tectonic environment: a combination of post-Rift thermal subsidence and eustatic rise, coincident with the development of the magmatic arch on the western part of the basin (caused by subduction of the oceanic proto-Pacific plate with Gondwana). At Lower Cretaceous, a rapid and extended marine flooding provided the anoxic conditions for accumulation and preservation of a thick package of organic-rich marine shales, of up to 400 metres of the Lower Agrio Fm. This lower unit is interrupted by a temporal episode of basin desiccation, depositing a few meters of sandy intervals, possibly associated with a disconnection with the proto-Pacific ocean due to the influence of the occidental magmatic margin. Right after, the basin experienced another extended flooding depositing the organic-rich Upper Agrio Fm., though not exceeding 100 meters. On top of it, prograding sequences consisting of clastic and carbonatic facies were deposited, and after that, another desiccation episode led to the deposition of anhydrite, and in some extent fluvial and eolian facies of the Huitrin Fm.

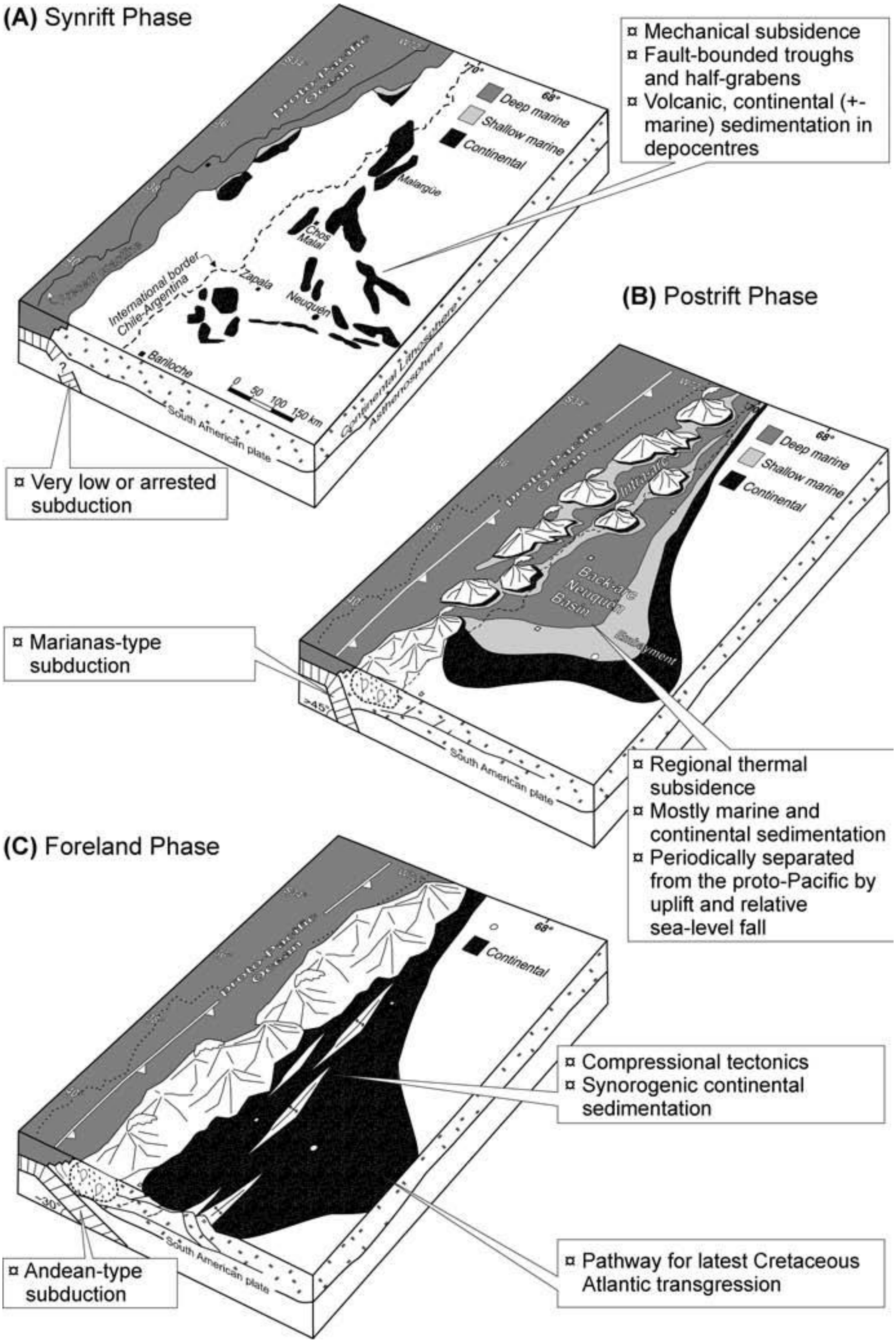

Figure 9: Schematic evolution of the Neuquén Basin. From: Howell, J., et al (2005).

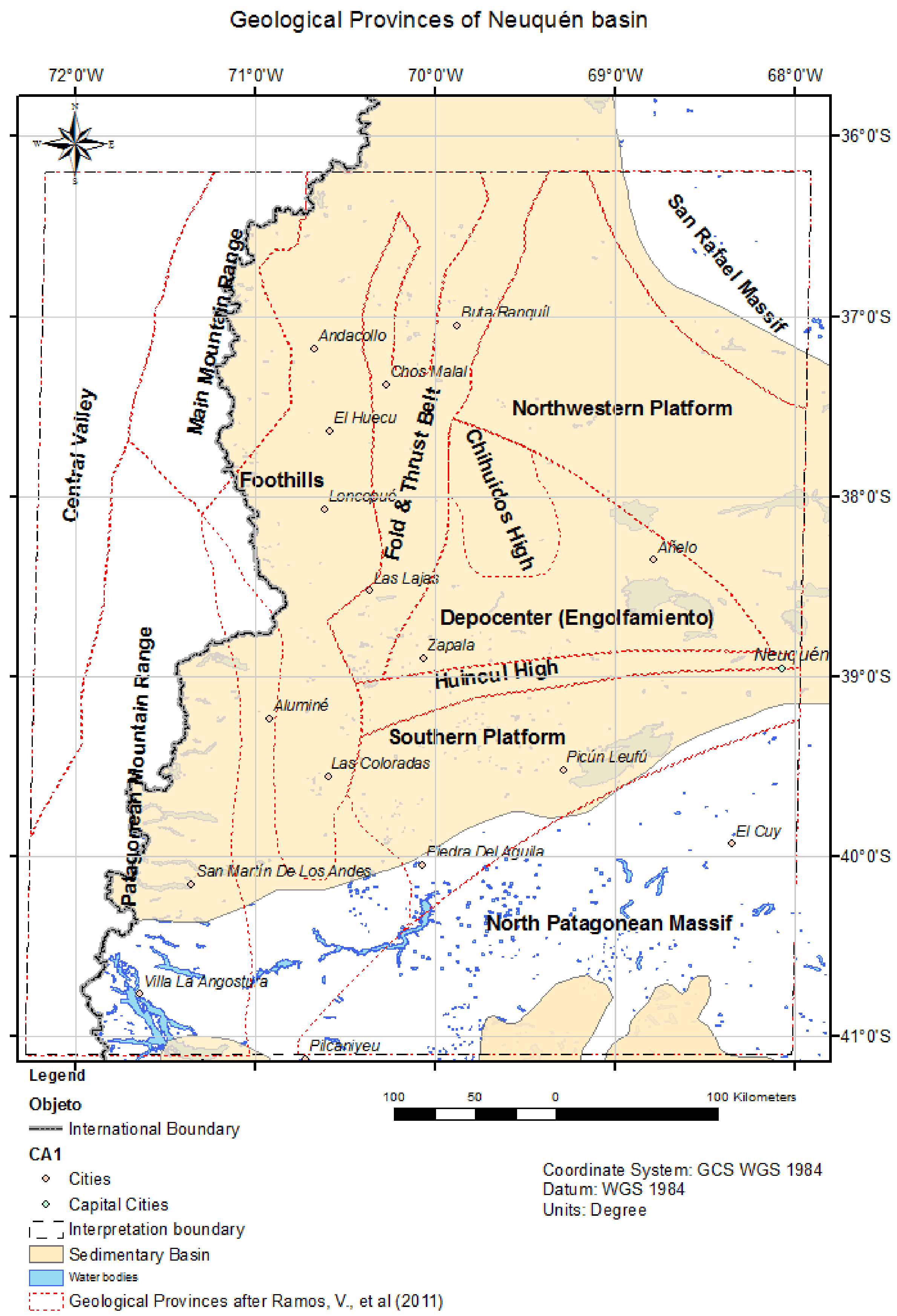

Figure 10: Geological provinces. Modified from Ramos, V., et al (2011).

Late Cretaceous to Cenozoic: Foreland phase.

This phase is a transition to a shallowly dipping subduction zone, leading to compression and flexural subsidence and the formation of a fold and thrust belt structure at the western margin (identified at Figure 10). It is noted the development of a compressional tectonic regime that caused inversion of some structures, a significant variation in the size and shape of the basin, and the eastward migration of depocentres.

Apart from the abovementioned regional tectonics, two other significant structural features, the Huincul High and the Chihuidos High, has exerted a main regional influence on the deposition, uplift and erosion of sediments, from the earliest times of the basin until recently (Arregui, et al., 2011). The Huincul High (or wrench zone according to some authors) it is described as a dextral E-W wrench faulting system located at the SE of the basin, giving to inversion of pre-existent depocentres. This inversion has affected the preservation and maturation of the source rocks in the area of influence, and hence, the unconventional petroleum systems. The Chihuidos High has been interpreted as a basement structure with N-S orientation, with different uplift pulses from Late Cretaceous until the Quaternary. At the same time, the fold and thrust belt associated with the subduction on the western margin, has played a significant role in the evolution of the basin on the W (Ramos, et al., 2011). Taking into account the tectonic evolution and associated depositional environments and regional structural features, the basin has been delimited into the following five geologic provinces: the Southern Platform (including the Picún Leufú sub-basin), the Huincul High, the basin Depocenter or Embayment (‘Engolfamiento’) including the Chihuidos High and the Añelo depocenter, the Northwestern Platform, and the Agrio and Malargüe fold and trust belt on the west (Figure 10).

I.3 Unconventional resources of Neuquén basin

Shale oil and gas resources

The Vaca Muerta Fm. is the main shale oil and gas reservoir of the Neuquén province, having reported in 2015 an average daily production of 25,000 B/D of oil (4,000 m^3/d), and 100 MMscf/D of dry and associated gas (3 million m^3/d), from 527 active wells (Huenufil Molina & Alonso, 2016).

Tight gas resources has been explored and produced by several operators in the Neuquén basin at least since 2006 (Masarik, 2014), and the potential of shale units has been identified as early as 1983 (first reported well producing form Vaca Muerta Fm.). However, possibly it was not until the publication of a report of global shale gas and oil resources assessment by the U.S. Energy Information Administration in 2011, that the industry realized the enormous potential of the unconventional resources in Argentina (EIA, 2013). The country has been identified as the most prospective for unconventional oil and gas production outside North America. Since then, some other assessment has confirmed the unconventional potential of Neuquén basin, giving an estimate (prospective resources) of 14 billion barrels of oil and 217 TCF of dry and associated gas for Vaca Muerta Fm., and 8 TCF of dry gas for Los Molles Fm., both identified as the main shale resources in the basin (EIA, 2013) (Gomes & Brandt, 2016).

Some of the main reservoir characteristics that make feasible to produce oil or gas form a shale unit, from a technical and economical point of view, are (Askenazi, et al., 2013): the total organic content (usually higher than 2%), large volumes (usually thickness > 30 m, extended throughout large area), thermal maturity (> 0.7 Ro%), adsorption capability (mainly for shale gas), and feasible to hydraulic fracturing (< 40% clay content). Other issues impacting feasibility are the reservoir pressure (overpressured will increase recovery factor), depth (shallow targets mean less drilling and completion costs), and favourable 'above ground' environment (installed infrastructure, reasonable services and resources, market, etc.).

Five organic-rich shales have generated and sourced commercial conventional reservoirs in the Neuquén basin (Legarreta & Villar, 2012). Hence all of them could be termed as potential (or actual) shale resources of the basin. Taking into account their anticipated potential in terms of thermal maturity, thickness, lateral extent and geochemical characteristics, Los Molles Fm. and Vaca Muerta Fm. has been extensively evaluated, and in the latter case, has been producing oil and gas since 2005 (EIA, 2013). A summary of the geology and geochemical characteristics of shale resources, with an emphasis on their unconventional potential, has been prepared from literature review, as follows.

Los Molles Fm

Around the latest times of the syn-rift phase, at Early Jurassic, a global eustatic rise launched a regional transgression from the western margin of the basin producing a relatively deep marine environment. Following pre-existent topography, a thick section of dark shale deposited on a reducing anoxic sea bottom. The shales of the Los Molles Fm. are laterally associated with deltaic and fluvial facies, and locally with coarse grained deep water deposits, all comprising the Cuyo Group. The shale interval changes laterally on its thickness, from tens to more than 800 metres, as well as their lithological and geochemical characteristics. The paleo-topography had large effect on sedimentation, while thickest intervals could be found into pre-existent half grabens and a large variation in organic content and type, too (Uliana, et al., 2014).

The tectonic evolution of the basin, including the successive uplifts of the Huincul High, also exerted a key influence into current depth and maturation of the shale intervals. The Early Jurassic sea distribution was probably disrupted by non-submerged areas, giving an uneven and complex distribution of facies, and the subsidence would have also played a role affecting sediment accumulation. During Mid Jurassic this paleo-geographic setting continued but the influence of the tectonics diminished, giving place only to thermal subsidence. This phase of thermal subsidence controlled the accumulation within the depocenter (or embayment). A large progradation of shallow water facies towards the basin is overlaid by sections of anhydrite of the Fm. Tábanos (the ultimate member of the Cuyo Group).

Los Molles shale has reported TOC around 1-5% with an oil prone type II-III kerogen. It is mostly associated with shale gas, apart from a thin surrounding volume at the oil window (Figure 11).

It has been reported that coarse deposits of Los Molles Fm., channelized submarine fans, have also potential as tight sandstones gas reservoirs (Barredo

& Stinco, 2014). Besides that, some of the proximal facies of the Cuyo Group has also potential as tight resources: shallow marine and deltaic clastic facies represented by sandstones, shales and coaly levels known as Las Lajas Fm.; fluvial and conglomerate facies designated as Challacó Fm. on the southern part of the basin, and as Punta Rosada Fm. on the northwest.

The productive Haynesville shale play in United States would be a valid analogue for Los Molles Fm. as a shale gas resource (Jorgensen, et al., 2013), based on it high overpressure (estimated from seismic velocities), mineralogy, depth, maturity and geochemistry, but with a much higher thickness of the whole sequence (500-800 m) and the net pay section (around 200 m).

So far, no major unconventional development has been identified for Los Molles Fm., despite being assessed between 130 – 275 TCF of recoverable gas (EIA, 2013) (Barredo & Stinco, 2014).

Vaca Muerta Fm.

It is the most notorious and promising unconventional resource in Argentina, and represents a significant marine transgression in the Upper Jurassic, which kept most part of the back-arc of Neuquén basin under anoxic conditions. Possibly there is not a valid productive shale play in United States to be taken as analogue to Vaca Muerta Fm. (Askenazi, et al., 2013). Although it share common characteristics regarding thermal maturity and mineralogy with Eagle Ford, and pressure gradient with Haynesville, Vaca Muerta shows a wider range of properties associated with it lateral and vertical heterogeneity, and a distribution of fluid accumulations from dry gas to light oil over an area of 30,000 Km^2 (Figure 12).

This unit shows vertical variation of properties, from a widespread basal section of 30-40 metres thick, only surrounded by littoral and shelf environments on a thin strip, showing high values of gamma ray on well logs, and high organic content. This interval is associated with the condensed section deposited during the main transgression event, and is followed by cyclic events of regression which deposited coarser clastics into the basin, diluting the overall organic content of the upper intervals of Vaca Muerta Fm. This upper section may be totally or partially eroded, giving a total thickness of 25-400 metres and a range of TOC of 3-8% type I-II kerogen, with high potential for liquid generation (Legarreta & Villar, 2012).

Apart from the vertical variability, Vaca Muerta shows lateral facies variation, and it’s possible to find coarser sediments inter-stratified with shales, high content of carbonates, or thin layers of volcanic ash, depending on the pale-geography during its deposition. Different types of oils have been produced from conventional reservoirs sourced by different organic facies of Vaca Muerta, from low maturity with high sulphur content, to intermediate and highly mature oils. Paraffin deposition and medium values of GOR has been also reported in oil producing fields (Martinez, et al., 2015).

Several exploration and pilot projects and the first unconventional development project in the basin have been identified for Vaca Muerta, currently producing oil and gas. So far, just the Loma Campana field has progressed from a pilot to a ‘factory drilling’ model (a description of the field at Appendix IV). However, according to the assessed recoverable volumes of 14 billion barrels of oil and between 170 – 308 TCF of gas (Barredo & Stinco, 2014) (EIA, 2013), this shale oil and gas resource is still on an early stage of development.

Other potential shale resources: Precuyano and Agrio

During Late Triassic to Early Jurassic syn-rift phase, organic-rich facies were deposited on deep lakes with saline-carbonatic waters, under restricted bottom conditions and semi-arid weather, and localized within areal restricted half-grabens. These lacustrine facies of the Precuyano Cycle, the Puesto Kaufman Fm., generally shows high TOC of 2-11%, and are proved source rocks for oil where the half-grabens have been tectonically inverted. In deeper locations it is expected to have shale gas potential or being over-matured. An estimation of 2-5 TCF is reported for this shale resource (Barredo & Stinco, 2014). Uneven distribution within depocentres, lateral and vertical heterogeneity, and high uncertainty of preservation and maturity would defer the exploration of this particular shale resource.

Both Lower and Upper Agrio Fm. show average TOC 2-3% (maximum 5%), of type II/II-III kerogen, which is mature in the NW region of the basin, having generated hydrocarbons at this positions due to enough upper Cretaceous and Tertiary overburden. Despite that, Agrio is not identified as a major unconventional resource apart from areas in the western region of the basin, where it could be at the oil window, involved into the fold and thrust belt, or preserved in complex and relatively deep structures (Legarreta & Villar, 2012). Recoverable volumes of gas for Agrio Fm. are estimated in 20 – 40 TCF (Barredo & Stinco, 2014).

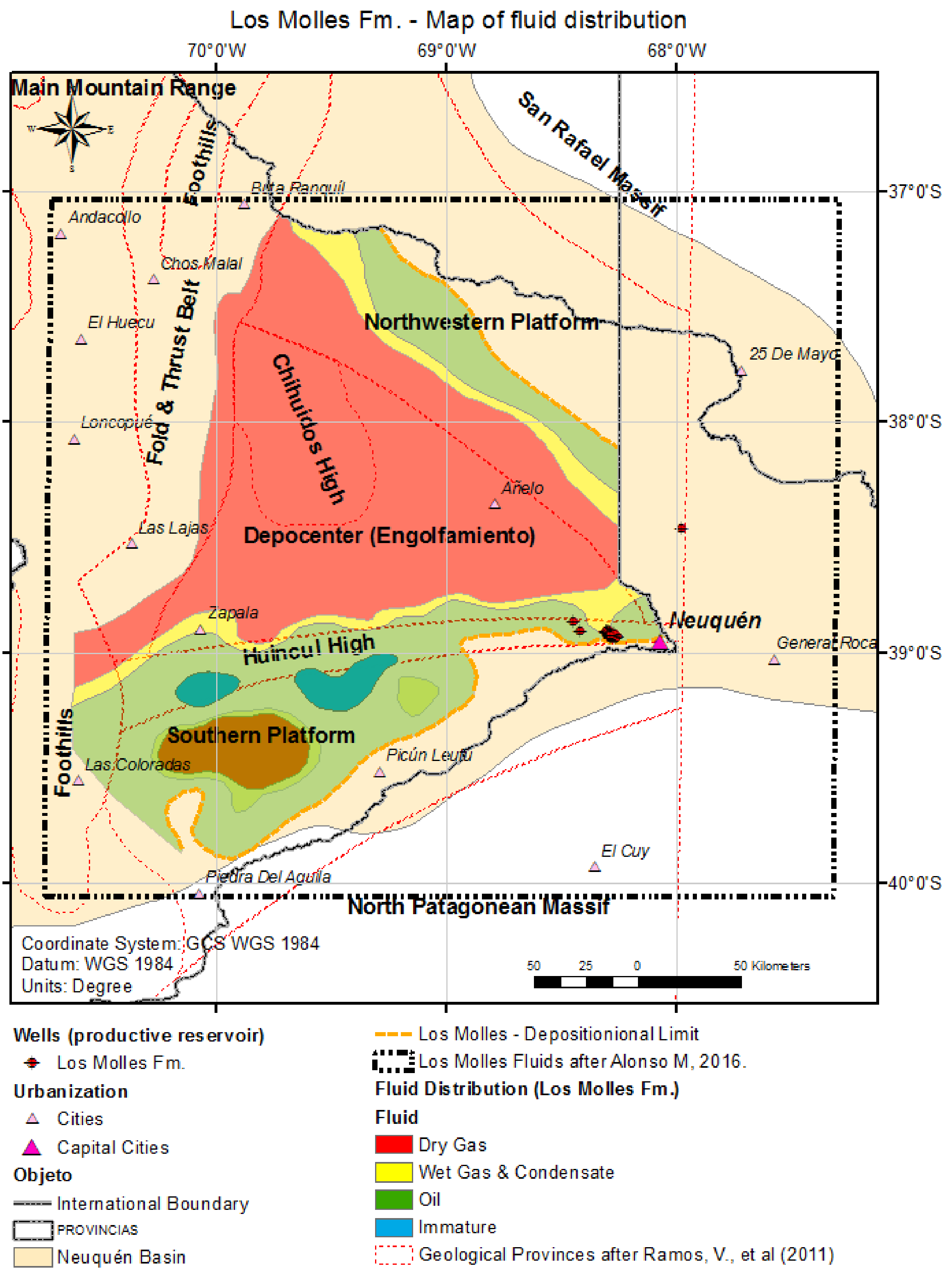

Figure 11: Distribution of fluids Los Molles Fm. Modified from: Alonso, M. (2016)

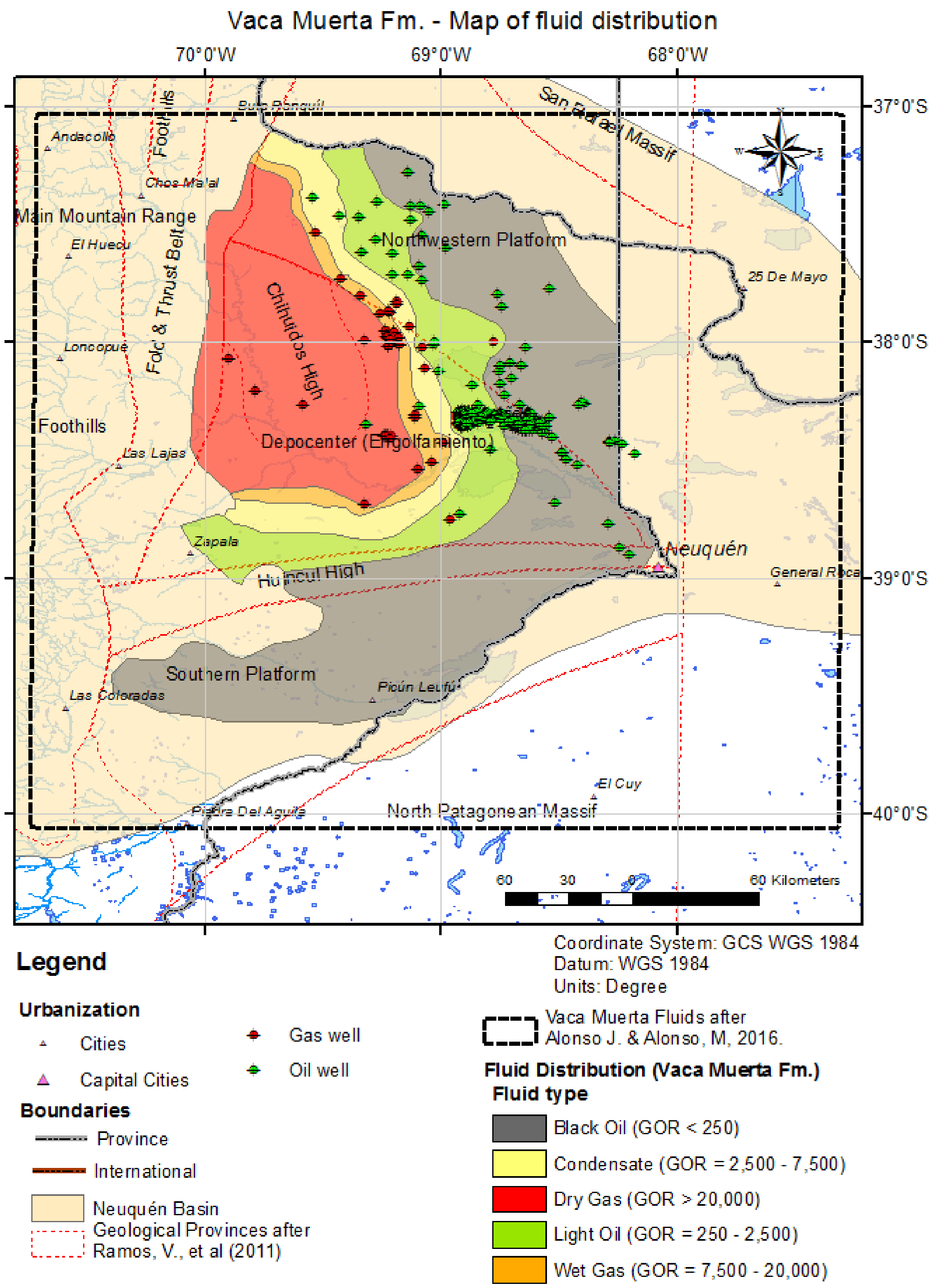

Figure 12: Distribution of fluids Vaca Muerta Fm. Modified from: Alonso, J. & Alonso, M. (2016).

Tight gas resources

In 2015, the reported average tight gas daily production in the Neuquén province was around 484 MMscf/D (14 million m^3/d) from 432 production wells targeting metamorphic basement rocks, sandstones and igneous intervals of the Precuyano Cycle, and the tight sands of Los Molles Fm., Lajas Fm., Punta Rosada Fm., Lotena Fm., Tordillo Fm., Sierras Blancas Fm. and Mulichinco Fm. (Huenufil Molina & Alonso, 2016) A map of the distribution of tight resources in the basin is shown at Figure 13. The following resources have been identified as the major contributors to current tight gas production.

Lajas Fm.

Sandstones, and in less extent, shales with abundance of carbonaceous debris, deposited on shallow marine, deltaic and estuarine environments, at the end of the transgression event which deposited Los Molles Fm. It is a traditional conventional reservoir along the Huincul High, showing a variable thickness that could reach up to 2,950 ft (900 m) in outcrops, and (Arregui, et al., 2011). Comprise three reservoir units with increasing permeability from base to top (reported permeabilities under in-situ stress: 0.001 – 0.1 mD). The unit is the major contributor to tight gas production in Neuquén basin, with some examples of large pilot projects as the Cupén Mahuida and Rio Negro fields (description at Appendix IV). Nevertheless, a higher tight gas potential of Lajas Fm. as a 'basin-centred gas system' has been recently identified (Raggio, et al., 2013), apart from localized current production.

Punta Rosada Fm.

Sandstones, conglomerates, and red and green shales deposited in fluvial-alluvial setting, are the continental equivalent of the Cuyo Group, sometimes contemporary with Lajas Fm. and Los Molles Fm. It is a proved conventional reservoir in the Huincul High and western region of the basin, reaching up to 2,950 ft (900 m) of sediments, thinning to the basin depocenter (Arregui, et al., 2011). Production of tight gas take place at several thin sandstone packages of Punta Rosada Fm. (2 – 5 m, possibly associated with disconnected fluvial channels), together with underlying massive sandstones of Lajas Fm. (20 – 45 m) has been reported at the Río Neuquén field (Barbalace, et al., 2014). A description of this particular field is included at Appendix IV.

Mulichinco Fm.

It was deposited immediately after an abrupt sea fall, possibly influenced by a tectonic uplift, generating a lowstand wedge extending from the north of the Huincul High to the northern region of the basin, and showing considerable changes in lateral and vertical facies (Schwarz, et al., 2011). The unit is composed of up to 1,650 ft (500 m) of continental to shallow deposits, and in the basin depocenter is one of the main reservoirs with petrophysical properties largely controlled by facies, stratigraphy and structural position. According to its high heterogeneity in poro-perm properties, it is possible to coexist conventional and tight reservoirs within a same field, with permeabilities ranging 0.01 - 100 mD. The wells show initial gas rates of 3.5 MMscf/D (0.1 m^3/d), declining to 1.5 MMscf/D (0.04 m^3/d) at the first month, and 0.7 MMscf/D (0.02 m^3/d) at the first year of production. An initial reservoir pressure of 2,350 psi at a depth of 4,163 ft (1,269 m), and a GOR range of 2 - 4.5 MMscf/bbl have been reported (Ucan, et al., 2007).

Other tight resources

It has been reported that the upper section of the Los Molles Fm. (a known shale resource as previously described), associated with a shallow-marine prograding wedge, that comprise sandstones, conglomerates and shale deposits, it is also a producing tight gas reservoir in the area of the Huincul High (Stinco, et al., 2008).

Other tight reservoirs are related to the pyroclastic rocks of the Precuyano Cycle, deposited during the extensional tectonics at late Triassic – early Jurassic rifting. Their reservoir characteristics are broadly affected by their geochemistry, post-depositional history and hydrothermal alteration (Barredo & Stinco, 2014).

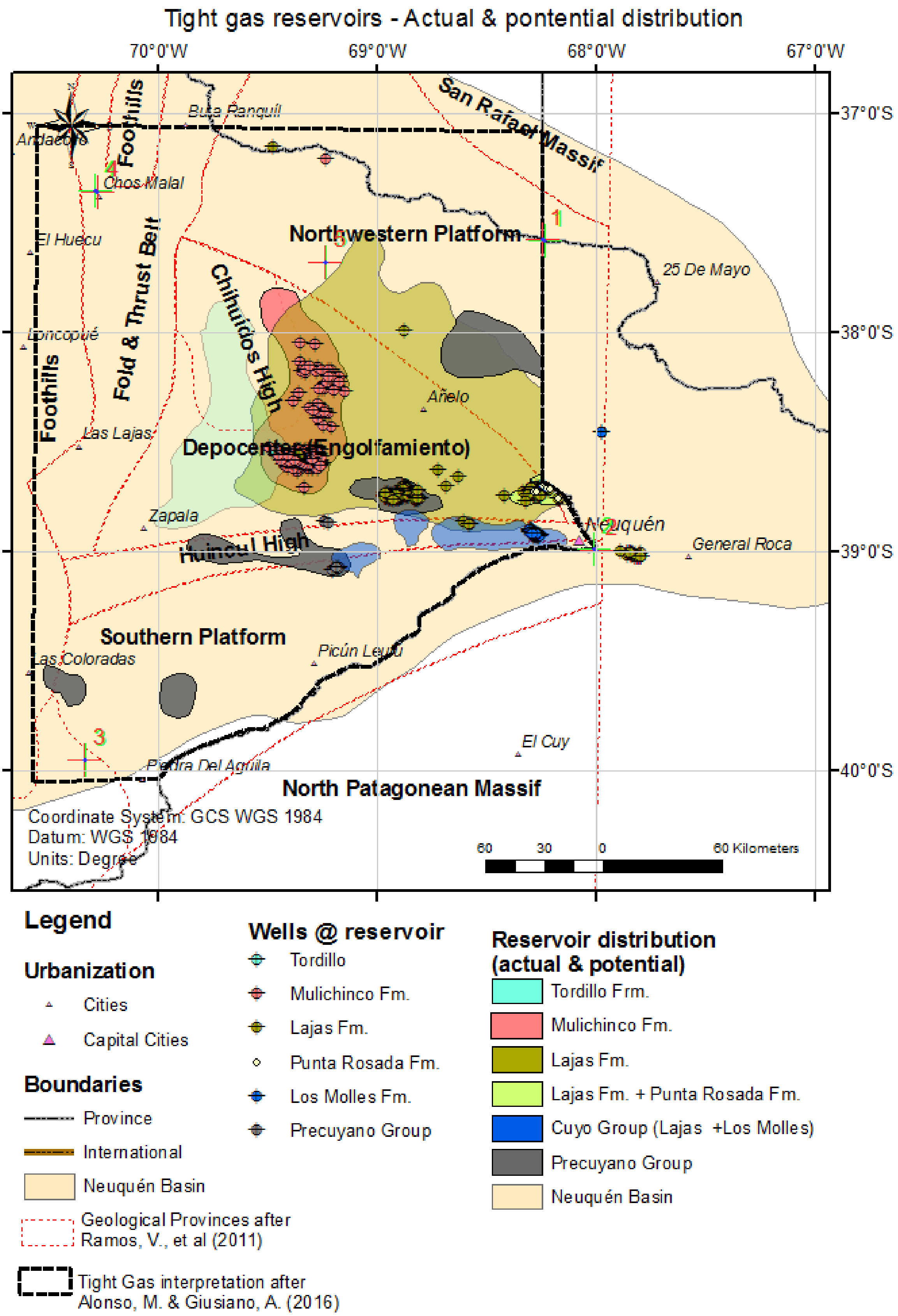

Figure 13: Distribution of tight resources. Modified from SEMH (2016).

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Appendix II: Production data

A comprehensive oil and gas production database is available in the public domain from the Ministry of Energy and Mining of Argentina (Ministerio de Energía y Minería, 2016). The operators report production data to the Ministry on a monthly basis, which can be downloaded as spreadsheets for each operator containing following type of data, informed for each well:

- Well location and identification: basin, province, block, field, coordinates, height, total depth, well number, code and type.
- Well status: type of exploration, production or other purpose (injection, disposal), and current condition (active, temporarily shut-in, etc.)
- Reservoir: type of resource (i.e.: unconventional, tight or shale) and main productive formation (85 reservoirs)
- Production data: monthly and cumulated production of oil, gas and water (or injection of water, gas or nitrogen); GOR, water cut, and extraction system (type of artificial lift).

The database discriminates among 9 types of artificial lift: sucker rod pump (SRP), hydraulic pump (HP), plunger lift (PL), jet pump (JP), electro submersible pump (ESP), gas lift (GL), progressing cavity pump (PCP), swabbing, other kinds not identified, or natural surge.

In order to compile useful data, 13 operators were identified form literature review as those having developed unconventional exploration and production activities, and the corresponding monthly production spreadsheets were downloaded and processed to discriminate only for wells at Neuquén basin targeting shale or tight resources. The database was accessed on November 2016, by when the most updated data belongs to October 2016, and that is the selected ‘present time’ for statistics of this thesis.

The data was processed and checked against data available in the public domain (Huenufil Molina & Alonso, 2016), and a very good agreement was found taking into account the differences in the reported periods, and the regional scope of the public reports. Following results are based on 583 shale oil wells and 73 shale gas wells (mainly from Vaca Muerta Fm.), and 582 tight gas wells (mainly from Lajas Fm., Mulichinco Fm. and Punta Rosada Fm.). A small proportion of wells identified as producing other fluids (neither oil nor gas), were generally removed for statistics.

II.1 Shale and Tight Production

Reported shale and tight production volumes in the last decade (Figure 14 and Figure 15) exhibit a clear growing trend, though unconventional sector in Neuquén Is still on an early development phase. Depending on the criteria of classification and location of tight and shale wells, the production of oil and gas from unconventional resources could be slightly altered from what is shown in Figure 14 and Figure 15, but there is fair certainty into this trend.

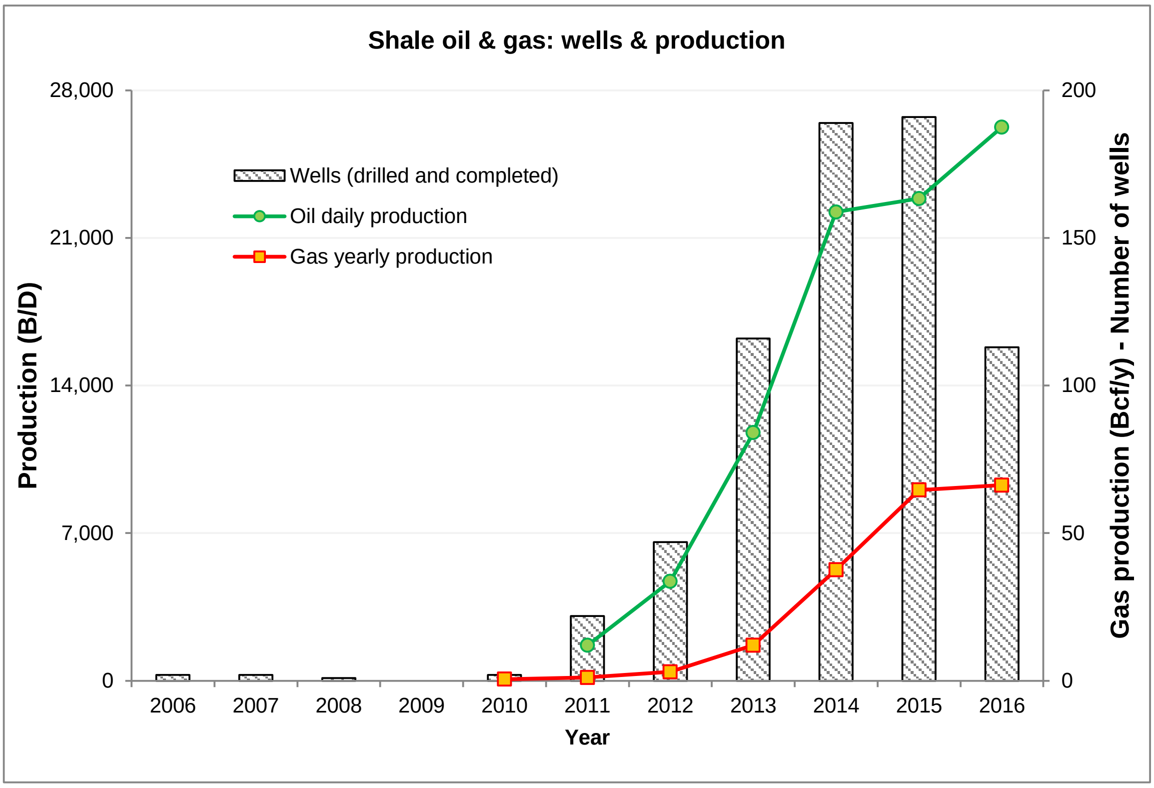

Figure 14: Shale oil production and number of wells in Neuquén basin (2006-2016).

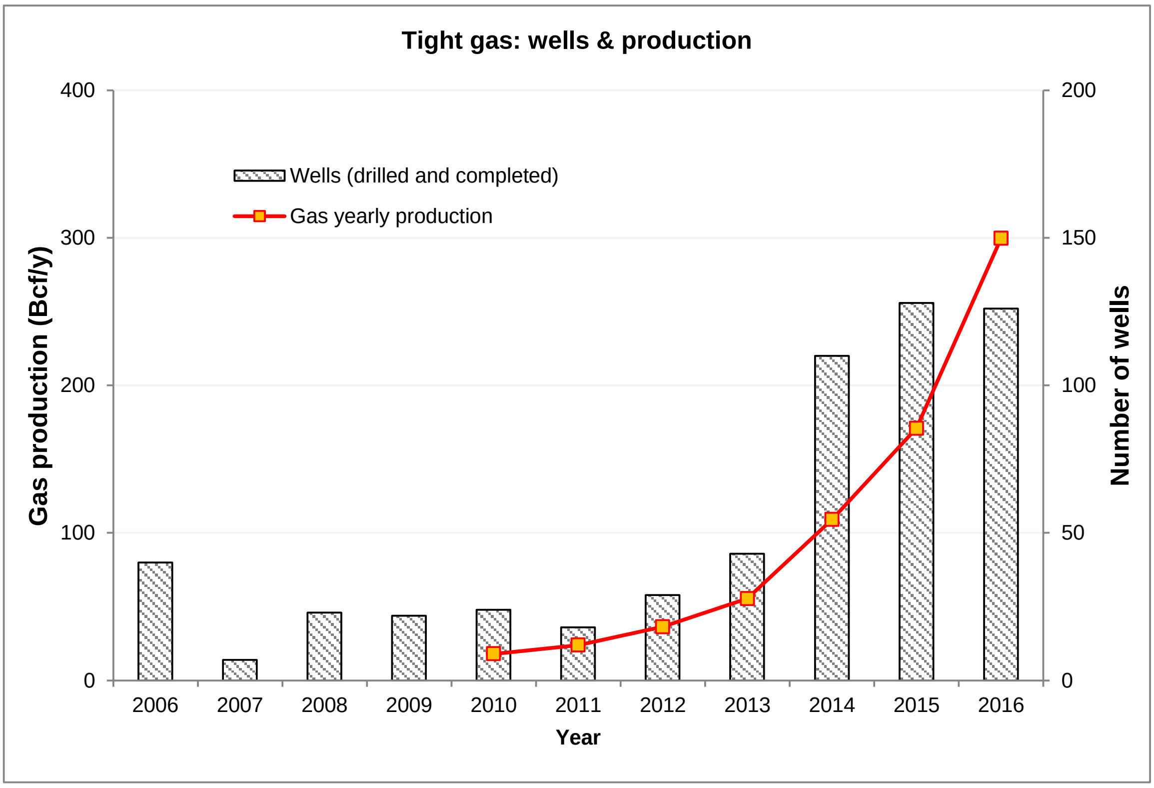

Figure 15: Tight gas production and number of wells in Neuquén basin (2006-2016).

Comprehensive exploration of Vaca Muerta Fm. shale began around 2010 (despite a few wells were producing before that), and pilot production around 2012, which is consistent with the production data, exhibiting the bulk of wells' life within 4 years (Figure 25). Tight gas exploration and pilot projects maybe launched a little earlier than shale, but once again production data shows a concentration of wells producing within the last 4 years (Figure 27).

The pace of development of those resources have been, and would probably be, slower than similar unconventional plays in North America. Nevertheless, a reasonable scenario for the long term, based on a recent report (Gomes & Brandt, 2016), is to expect the drilling and completion of around 9,800 wells within 2016 – 2030. A raw estimate of the economics associated with this development scenario, and the capital and operational expenditures to be allocated on artificial lift, predicts a range of 2,000 to 5,000 USD in the period, a minor amount compared with the forecasted drilling and completion Capex of 73 billion USD (further discussion on assumptions and data is presented at Appendix V).

II.2 Reservoirs and Well configuration

For the tight and shale resources in Neuquén basin, it was detected a large heterogeneity in reservoir and fluid characteristics (i.e.: depth, gas/oil ratio, production decline curves), and production behaviour and technologies (i.e.: drilling and completion approach, well configuration, production management), even at the field scale. At the same time, current unconventional exploration and production has developed into a few fields within the basin, hence with the incorporation of other areas and other tight and shale resources currently underexplored, a broader diversity is expected in the future.

Vaca Muerta Fm. exhibit similar metrics than certain shale plays in North America (i.e.: Eagle Ford, Woodford and Haynesville) in terms of reservoir characteristics, production behaviour, and well depth, as shown in Table 1. From literature, it is also anticipated that will exhibit other similar range of parameters which affect artificial lift selection and performance: moderate to high GOR and complex well configurations (geometry and architecture). Vaca Muerta Fm. shale gas wells are generally deeper than oil wells, but it seems to exhibit a similar declining behaviour, though not much information has been published. In the case of tight gas reservoirs, generally exhibit larger permeabilities (a range of 1 to 100 µD is reported for Lajas Fm.) and then declining behaviour is not as radical as in shale reservoirs (compare Figure 5 and Figure 6 with Figure 7).

Metric	Vaca Muerta (Oil, Vertical)	Vaca Muerta (Oil, Horiz.)	Vaca Muerta (Gas, Vertical)	Eagle Ford (1)	Woodford (1)	Haynesville (1)
Typical TVD (ft)	9,200 to 10,800	9,200 to 10,800	9,400 to 14,800	6,000 to 13,000	10,000 to 16,000	10,000 to 13,500
Typical Lateral (ft)	NA	3,900 (2)	NA	3,500 to 5,000	4,000 to 5,000	4,000 to 7,600
Permeability (µD)	0.06 to 0.2 (3)	0.06 to 0.2 (3)	0.06 to 0.2 (3)	1	< 1	< 1
Avg Decline - Year 1	73%	64%	47%	75%	59%	81%
Avg Decline - Year 2	30%	29%	35%		43%	41%
Avg Decline - Year 3	19%	19%	26%		32%	26%
Decline out years	NA	NA	NA	6%	5%	5%
Water Usage (10^6 gal)	NA	4 (2)	NA	5	4.5	6
Water Flow back	NA	NA	NA	5 to 30%		
Sources:						
Average decline from typical production decline curves, after Huenufil Molina, C. (2015) and Olmos, S. (2016)						
(1) Lane, W. & Campbell, S. (2017)						
(2) Report of the performance of an horizontal shale well of 15 frac stages, after: Suarez, M., et al (2015).						
(3) Corrected at in-situ stress, after: Herrero, F., et al (2014).						

Table 1: Shale wells metrics in Neuquén and North America.

The rocks that comprise shale and tight resources of Neuquén basin are widespread over large areas, and depending on the structural evolution of the places where they were deposited, could have experienced significant events of uplift and/or overburden. They can be found at outcrops that have resulted in valuable spots for reservoir characterization, or to be inferred at very deep structural positions, from seismic data and deep exploration wells. Therefore, it is not realistic to determine 'the depth' of shale and tight resources, but a depth range of the play fairway (at which shale or tight resource exhibits the most auspicious characteristics or potential). From monthly reports, most of the shale oil wells inform a depth within 9,200 – 10,800 ft (2,800 – 3,300 m), as shown at Figure 16. It is not clear if the informed depth at the reports it is measured or total vertical depth (which would bias the data to higher depths that actual considering deviated and horizontal wells), and a significant number of wells report a zero value (23%). Anyway, those values are consistent with reported Vaca Muerta Fm. depth at Loma Campana field (Martinez, et al., 2015). As of Figure 17, it seems that shale gas wells are drilled to deeper targets, within 9,400 - 14,800 ft (2,850 - 4,500 m); this is coherent with an expected higher maturity and gas potential for Vaca Muerta Fm. at higher depths.

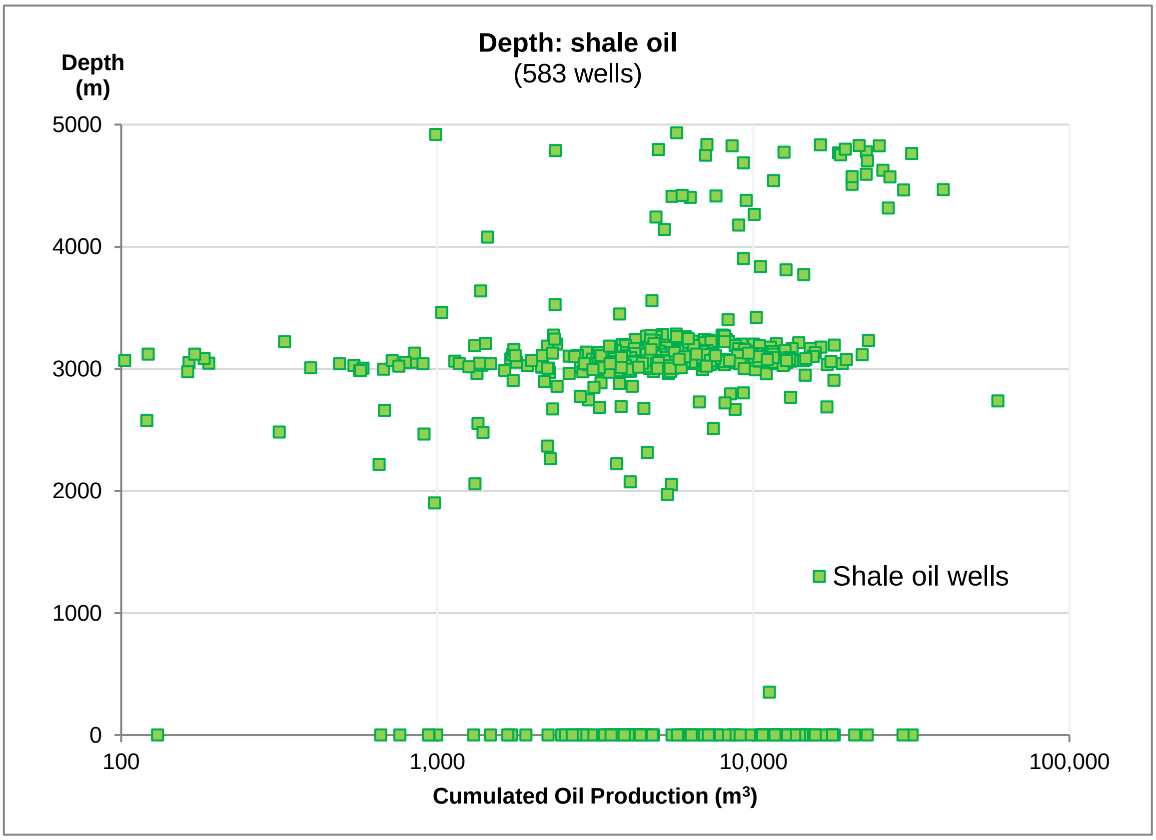

Figure 16: Total depth of shale oil wells.

Regarding total depth of tight gas wells, a different pattern from shale is recognizable at Figure 18, showing three distinct clusters: a cluster of relatively shallow wells within 5,300 - 6,912 ft (1,600 – 2,100 m), and two or three overlapped clusters within 8,200 - 14,483 ft (2,500 – 4,400 m). Depth clustering is consistent with the existence of different tight reservoirs, located at different structural positions depending on the field location. For instance, it is reported that Lajas Fm. is targeted within 6,600 – 9,900 ft (2,000 – 3,000 m) at Cupén Mahuida field, and Punta Rosada Fm. lies at 9,200 - 12,800 ft (2,800 – 3,900 m) at Río Neuquén field (SEMH, 2014). According to reports, Mulichinco Fm. seems to be exploited at shallower depths in many fields, which is consistent with the shallow cluster identified at Figure 18.

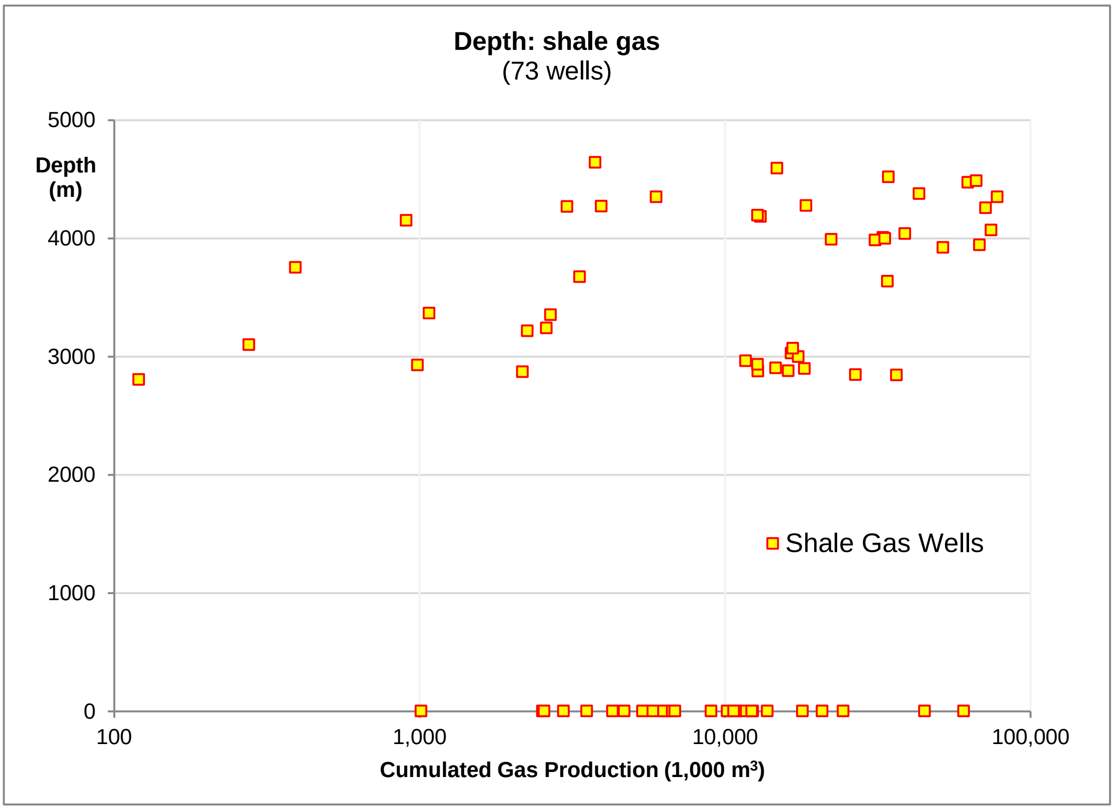

Figure 17: Total depth of shale gas wells.

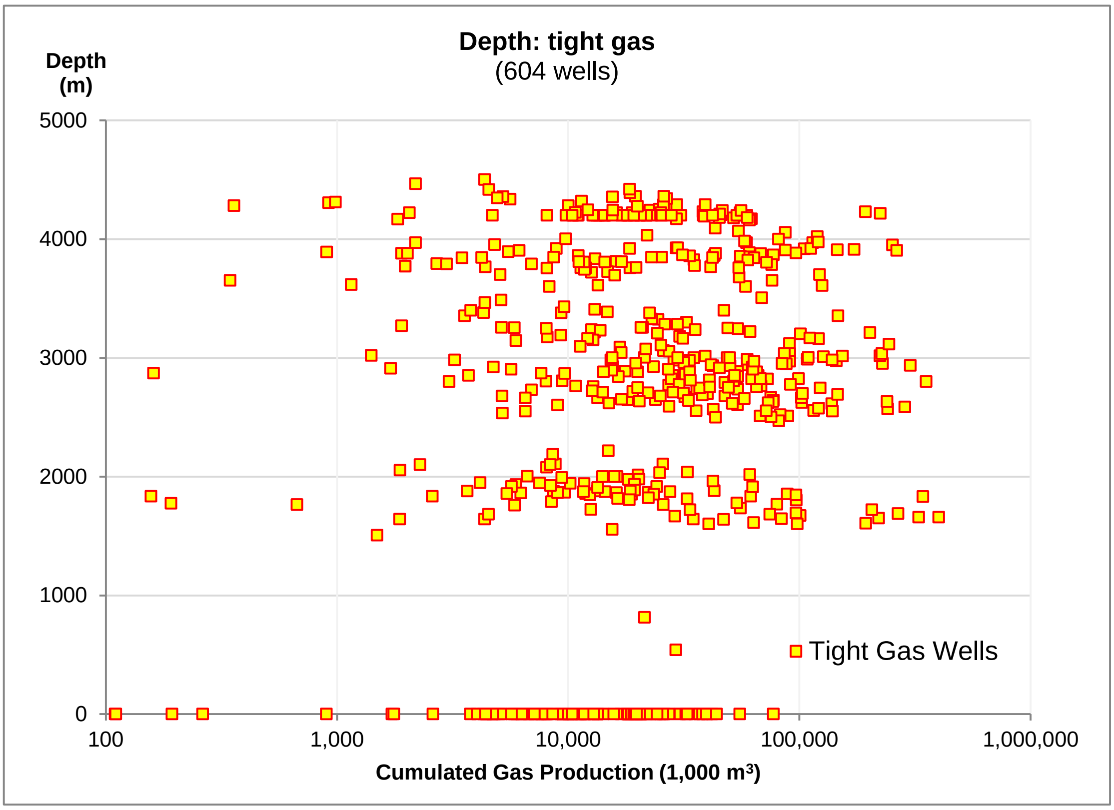

Figure 18: Total depth of tight gas wells.

The rapid declining behaviour of shale and tight wells is noticeable when examining the production flowrates of oil and gas during wells' life (Figure 25, Figure 26 and Figure 27). Initial shale oil wells' production is in the range of 200 – 700 B/D (30 – 110 m^3/d), but the bulk of wells with 1-2 year production show 5 – 100 B/D (1 – 16 m^3/d). It seems that tight gas wells exhibit a less declining behaviour than observed for shale oils, what is consistent with typical production decline curves from literature (Figure 7).

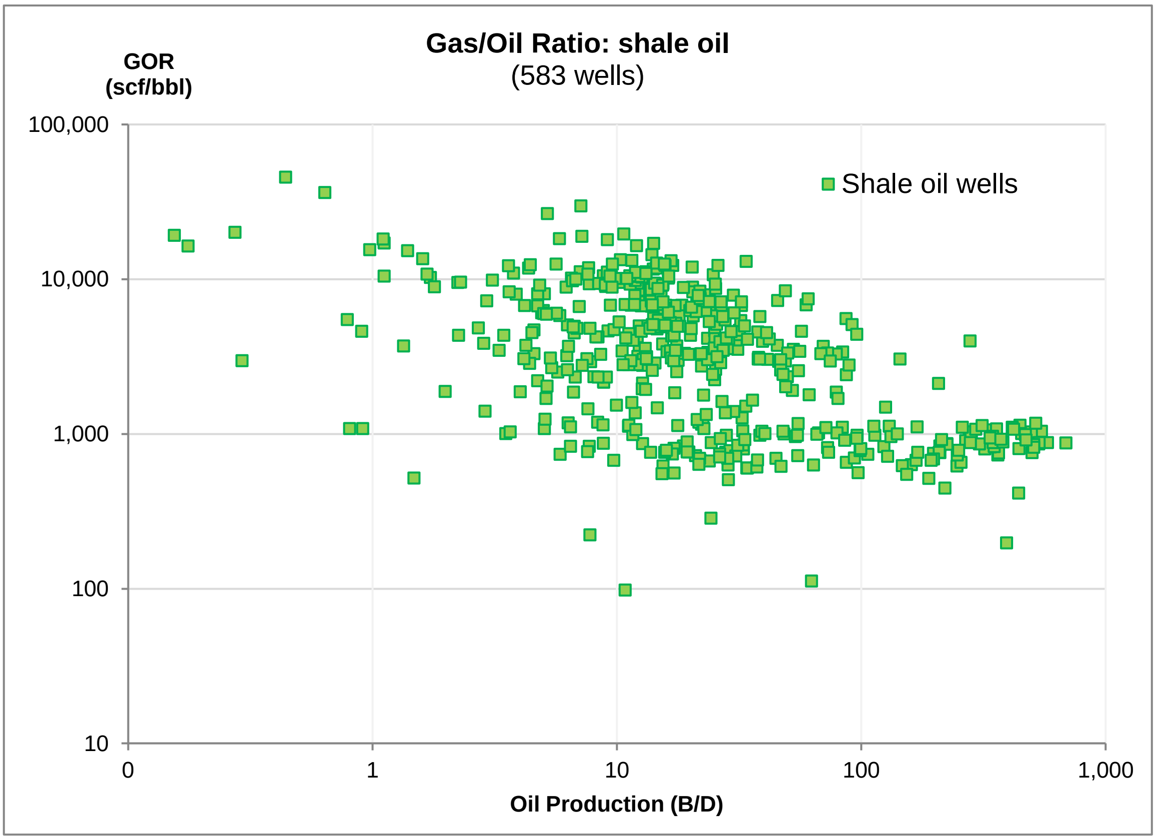

Figure 19: GOR shale oil wells.

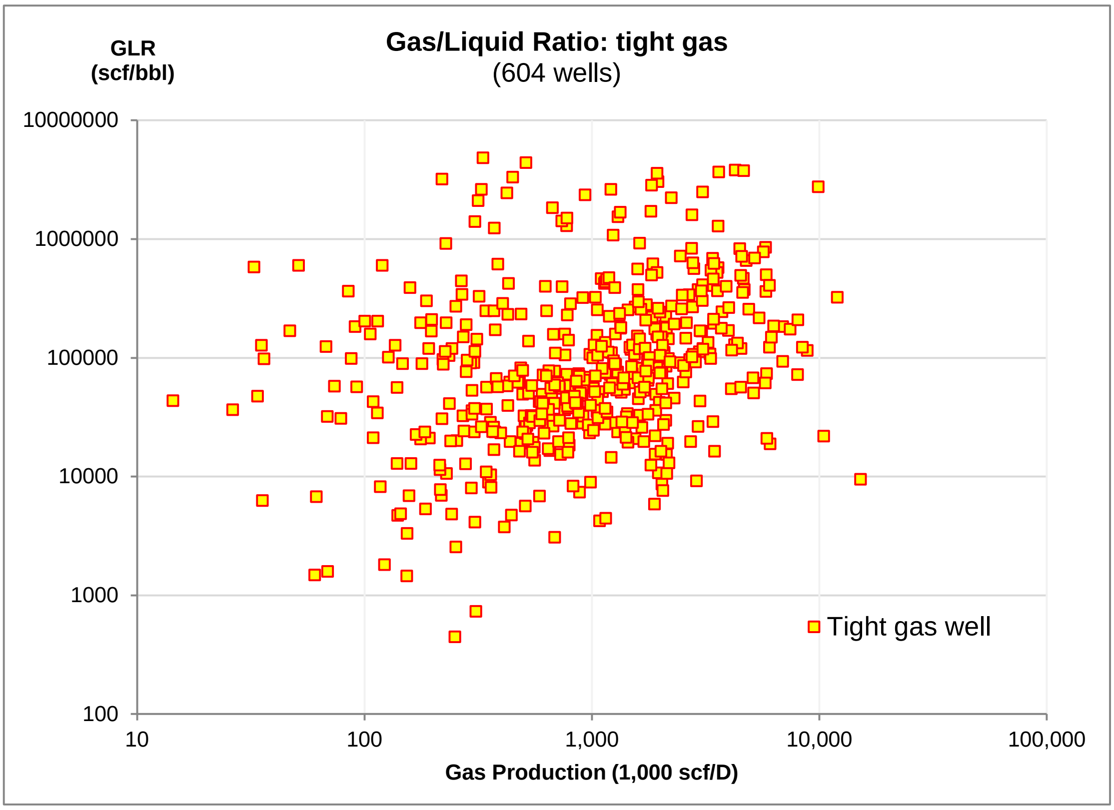

Figure 20 : GLR tight gas wells.

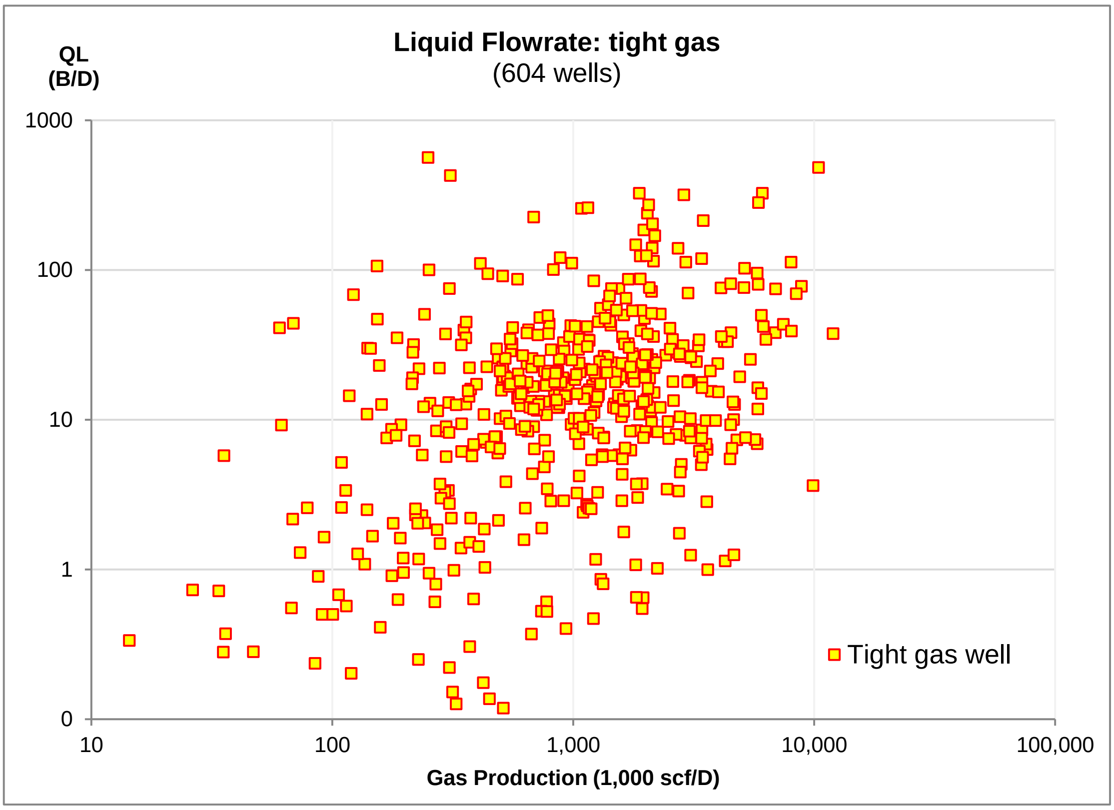

Figure 21: Liquid production for tight gas wells.

Regarding gas/oil ratio, shale oil wells exhibit a broad envelope of values within 500 – 15,000 scf/bbl (89 – 2672 m^3/m^3) (Figure 19), indicating that current production comprise both black and light oil. Those values are consistent with the reported values in literature, showing a significant variation even at the field scale (Martinez, et al., 2015).

On the other hand, tight gas wells do not exhibit a single behaviour in terms of the production of liquids (oil, condensate or water); the gas/liquid ratio shows a high dispersion as of Figure 20. Nevertheless, only 14% of the wells surpass a reported liquid production of 50 bbl/MMscf (Figure 20 and Figure 21). Such relatively small value is an indication that having enough bottomhole pressure, most of the tight gas wells will produce liquids without the need of a lifting method, consistent with the low percentage of artificial lift installed in tight wells. Shale gas wells exhibit a similar behaviour.

Well architecture and geometry is not informed in the production reports then literature review and the information provided by experts were very useful to explore this issue.

Drilling and completion practices are migrating from a vertical and deviated geometry to horizontal wells with large laterals with 10 - 15 (or more) fracturing stages. This will comprise drilling from a single location through 4, 6 and 8-well pads which gives S-shaped wells or horizontal wells, increasing effective drainage area (Wagner, et al., 2016) (Martinez, et al., 2015) (Gomes & Brandt, 2016). Simultaneous operations of stimulation and production in nearby wells can promote shear movements at the reservoir interval, causing casing restrictions (Rimedio, et al., 2015). Adding complexity to well geometry would affect the planned completion of the well (i.e.: reducing the number of stages possible to be attained, hence impairing well performance), but also long term well performance and operation, including proper installation, retrieval and/or operation or artificial lift equipment. Downhole additional equipment and higher standards of materials would be necessary to properly install and operate certain artificial lift systems, to attain efficiency and reduce maintenance; in some cases the use of certain methods would be excluded because of highly deviated and complex well geometry.

Another expected impact of evolving well geometry is on a more challenging flow regime for lifting methods. That’s the reported case in North America for horizontal wells with long lateral sections, not straight horizontal but toed up and/or down to navigate the sweet spot. In wells with high GLR and relatively low pressures, as would be expected at the mid to late life for unconventionals, a slight change in the slope of the horizontal section can create a trap for liquids that creates backpressure and an initiation for unstable flow. Apart from that kind of behaviour when reservoir pressure has dropped enough, turbulent slug flow has been observed in most shale wells in North America, which creates problems in surface equipment, and also presents a challenge for gas handling devices in artificial lift system designed for a stable gas content stream, not adequate when gas is present in slugs (Lane & Chokshi, 2014).

Some providers have reported that typical production wells' architecture in Neuquén basin (tubing sizes 2 7/8" or 2 3/8", casing 4 ½") may exclude or challenge certain artificial lift systems, because of the near slim tubing requirements, or the small tubing-to-casing annular space.

II.3 Artificial Lift trends

In terms of the reported systems for lifting unconventionals, 75% of active shale oil wells currently use mainly plunger lift or sucker rod pumps (Figure 22), while the use of artificial lift for gas production is much less extensive, with just 14% of shale gas wells and 6% of tight gas wells producing mainly under plunger lift (Figure 23 and Figure 24). There is an observable trend for shale oil wells natural flowing for around 1 - 1.5 years, when plunger lift (51%) or sucker rod pumps (24%) are installed, which is consistent with current practices reported in the literature (Martinez, et al., 2015). On the other side, it is difficult to identify any artificial lift scheduling trend for shale and tight gas wells, but possibly a similar approach is followed: the wells flow naturally until requiring the installation of a deliquification system, if liquid load arise. When data is gathered by current daily production, the same trend in the timing of natural flow and artificial lift installation can be recognized (Figure 25, Figure 26 and Figure 27).

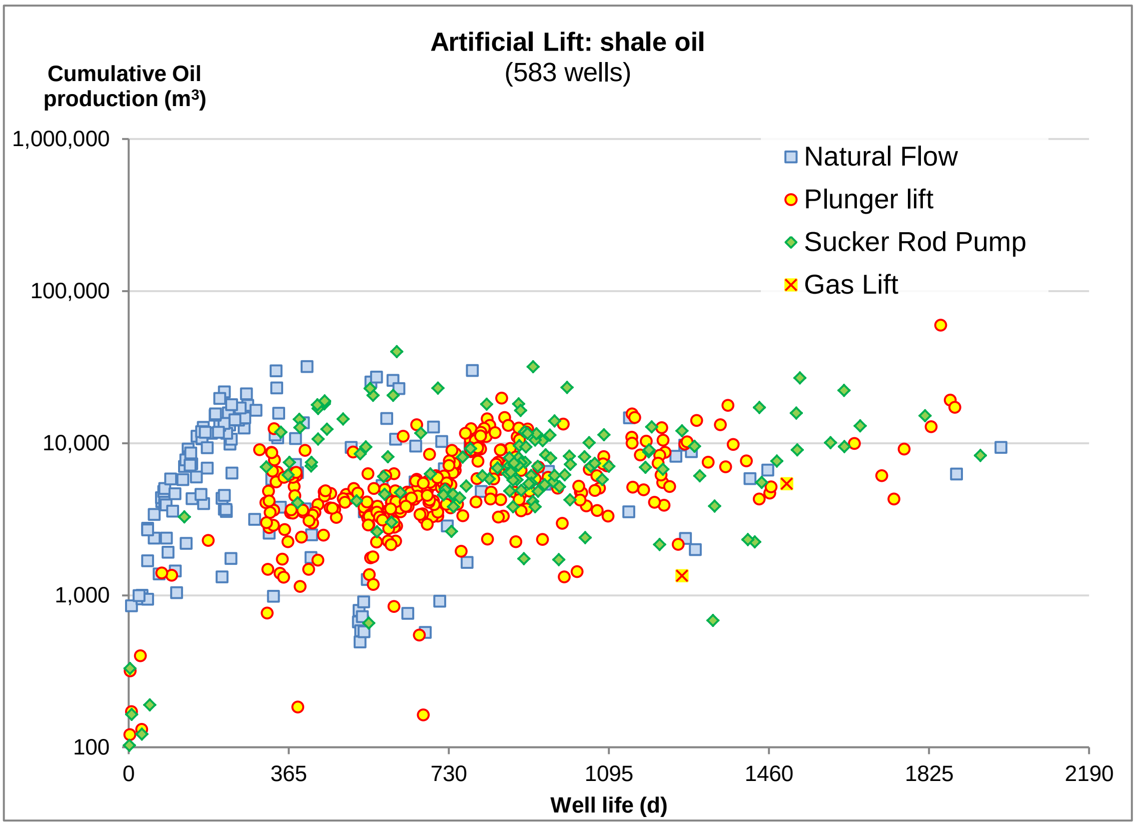

Figure 22: Artificial lift in shale oil wells.

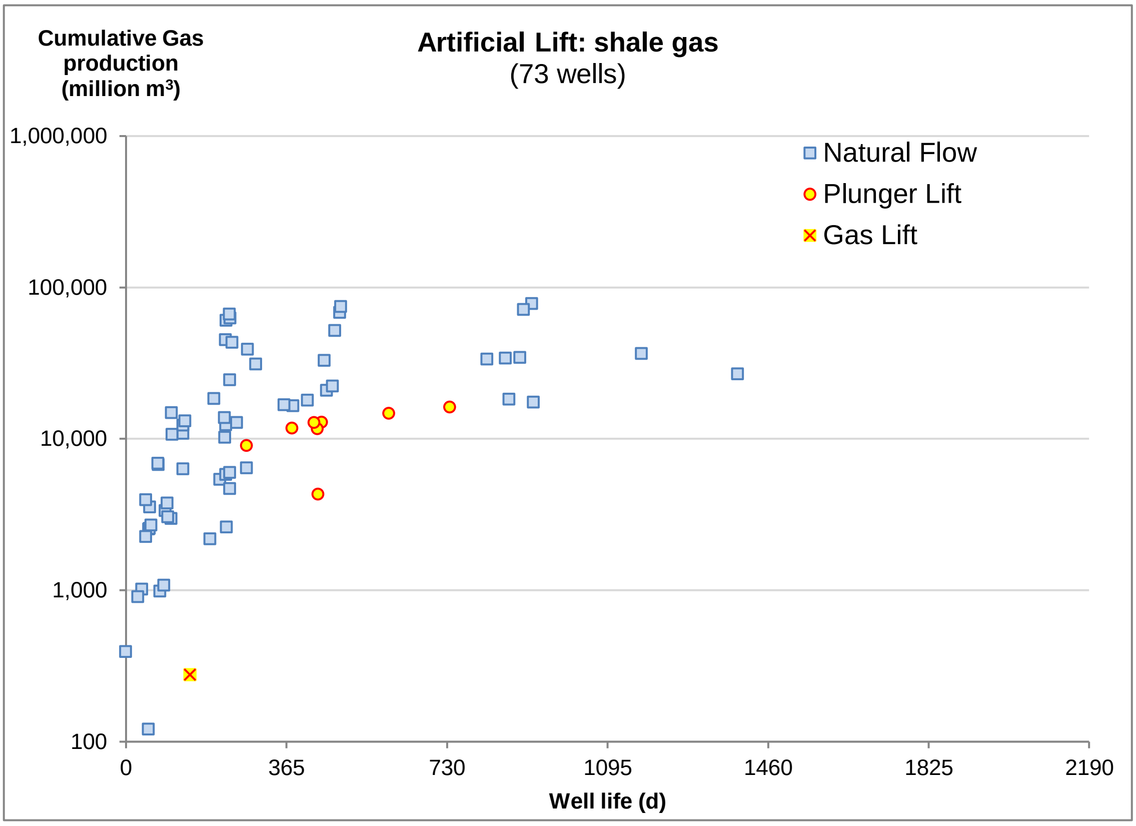

Figure 23: Artificial lift in shale gas wells.

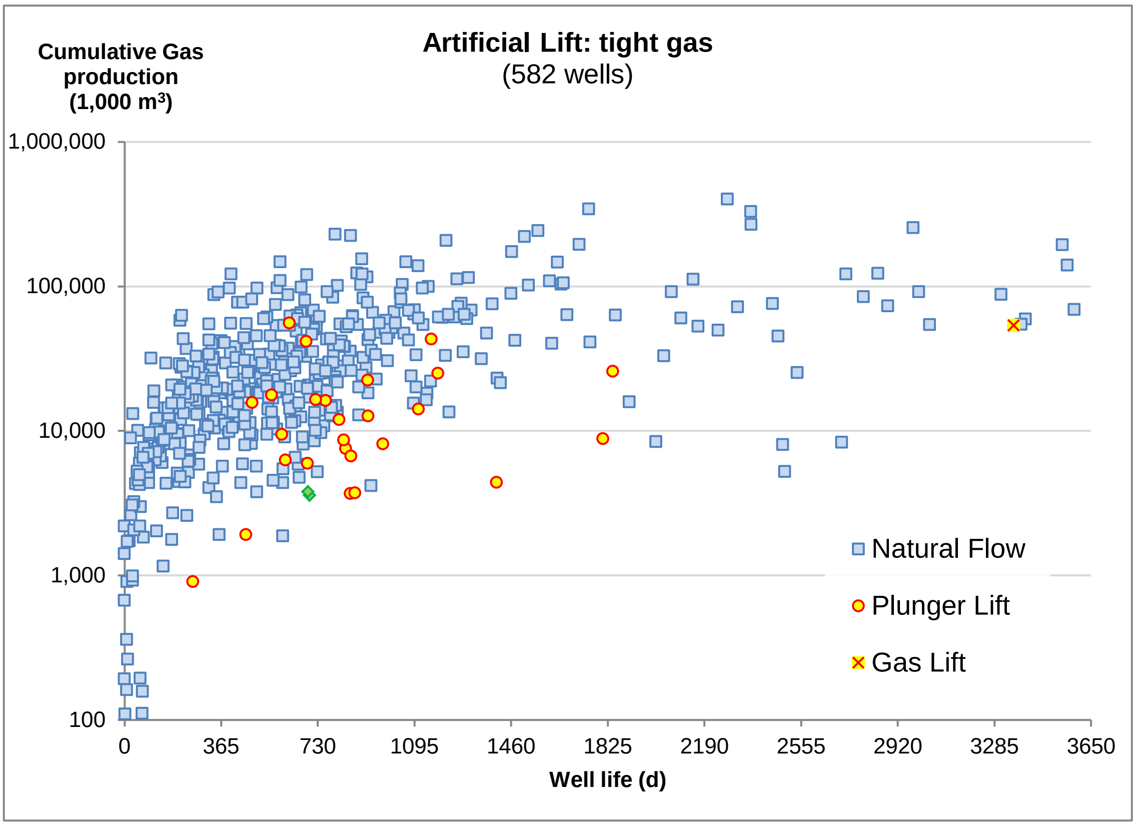

Figure 24: Artificial lift in tight gas wells.

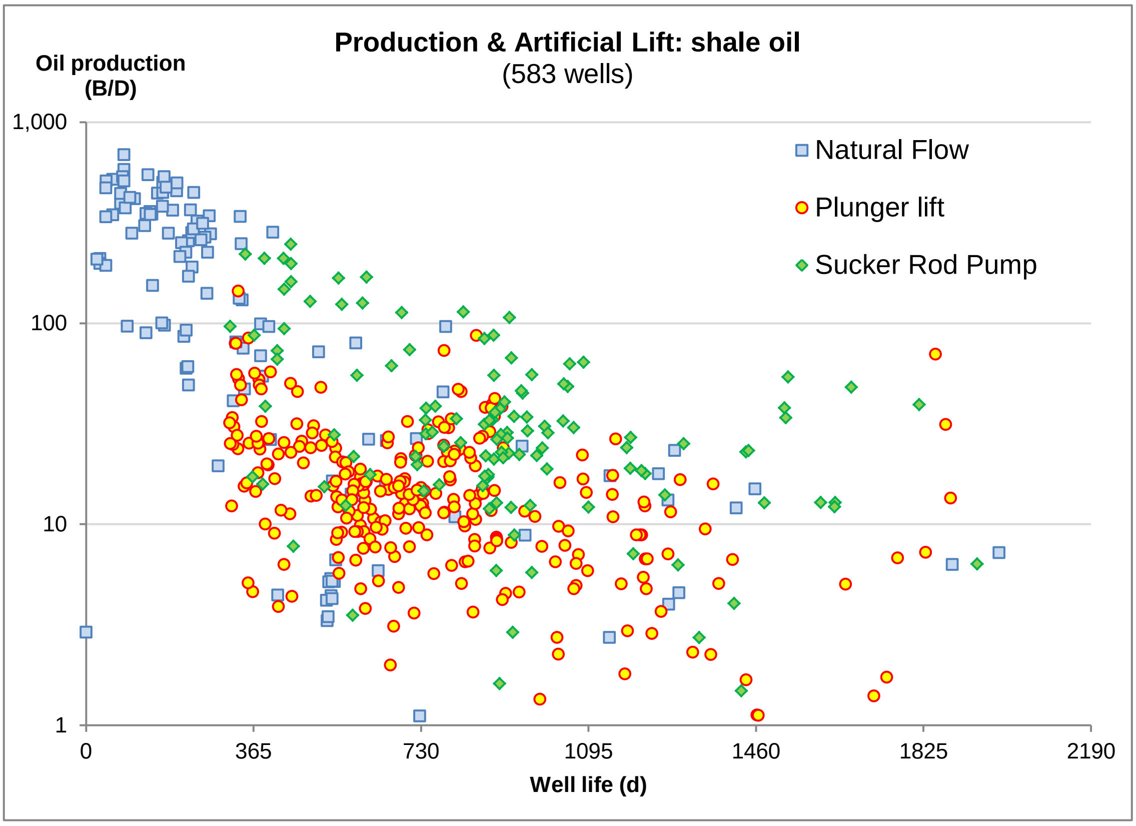

Figure 25: Production and Artificial lift in shale oil wells.

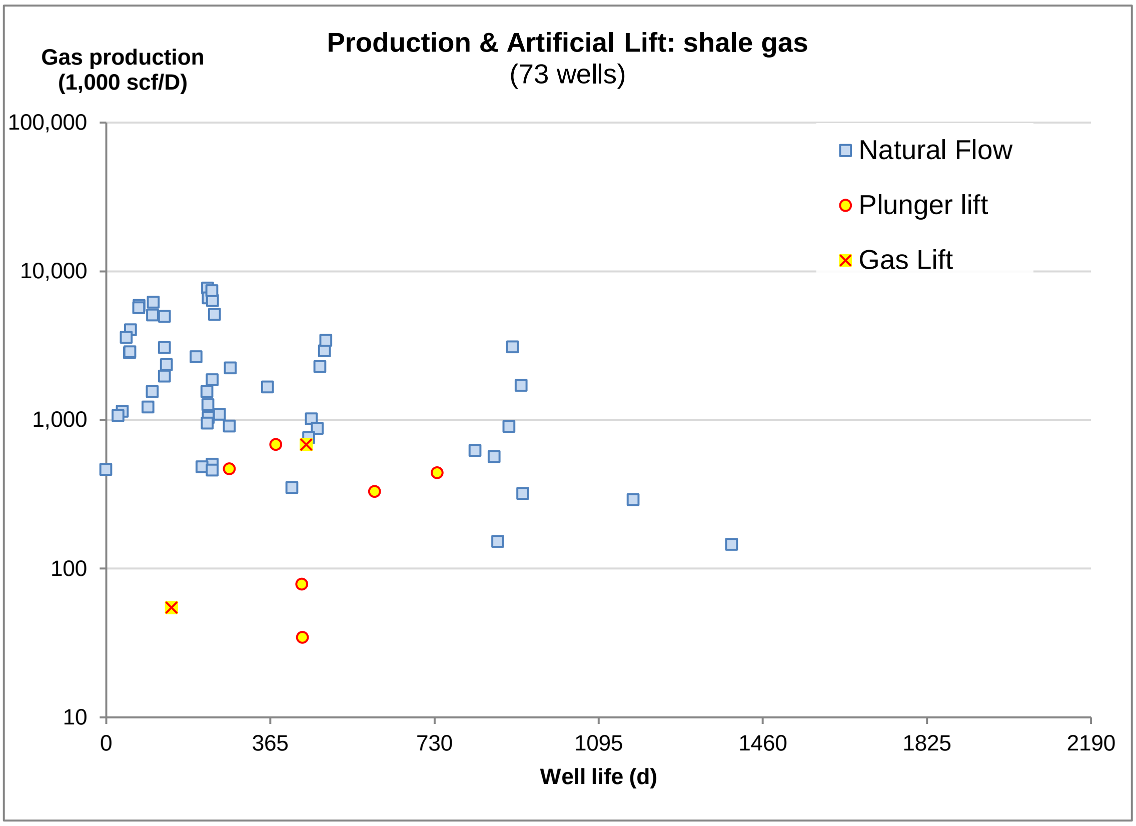

Figure 26: Production and Artificial lift in shale gas wells.

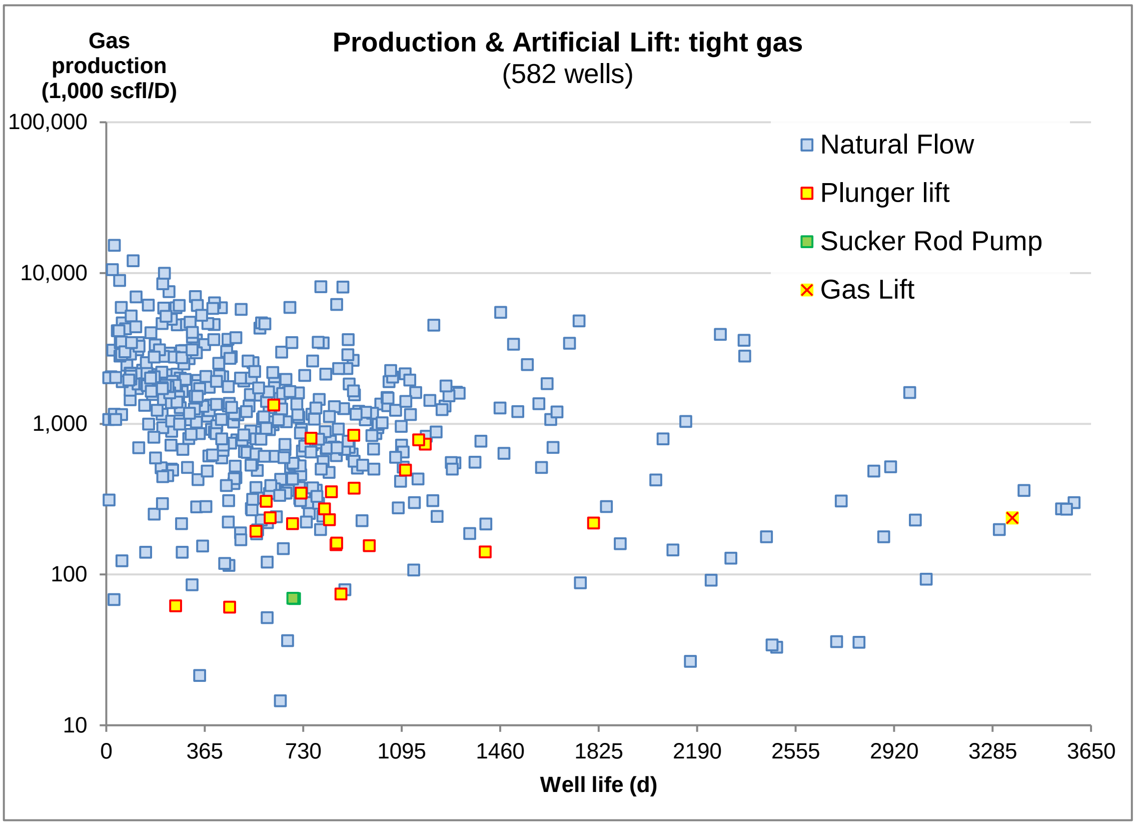

Figure 27: Production and Artificial lift in tight gas wells.

Appendix III: Artificial Lift Systems

III.1 Lifting Methods

Artificial lift systems use the fluid energy (passive methods) or transfer energy from the surface to the wellbore fluid (active methods), to achieve an economic flowrate from the well, and/or optimize recovery of hydrocarbons in place.

Sometimes, artificial lift is necessary to stabilize production flowrate from an intermittent well, or even to resume production from a ‘dead’ well. All methods are intended for liquid fluids’ flow; therefore the most comprehensive applications are concentrated in oil production. Though, some systems are also feasible to apply on gas wells, with the aim to unload smaller amounts of liquids that cannot flow together with the gas stream and accumulate at the wellbore bottom interfering or locking gas flow. This application is usually designated as ‘deliquification’. In any case, artificial lift systems have a direct impact on the economics of the field.

This section contains a summary description and illustrating figures of the main artificial lift systems in use at the industry, which were selected and assessed for their actual or possible applications in shale and tight wells:

- Sucker Rod Pump (SRP).
- Plunger Lift (PL).
- Gas Lift (GL).
- Electric Submersible Pump (ESP).

- Jet Pump (JP).
- Progressing Cavity Pump (PCP).

A general classification is based on the dynamics of the systems: passive systems (i.e.: taking advantage of fluid energy), or active systems (i.e.: a moving element downhole transfer kinetic energy to the fluid, which is converted in potential energy as fluid pressure boost).

Sucker Rod Pump (SRP)

Also termed as beam pump or mechanical pump, it is the most used lifting system in the world, in particular for mature onshore fields, low flowrates and shallow wells. The pump installed downhole consist of a fixed barrel with a standing valve (intake), and a travelling valve (discharge), and a reciprocating cylinder moving inside the barrel, connected to surface through sucker rods, which activate those valves in it ascending (discharge) or descending (suction) trips. At surface, a prime mover (gas or fuel engine) drives the reciprocating movement of the surface pumping unit, which in turn moves up and down the sucker rod string inside the production conduit.

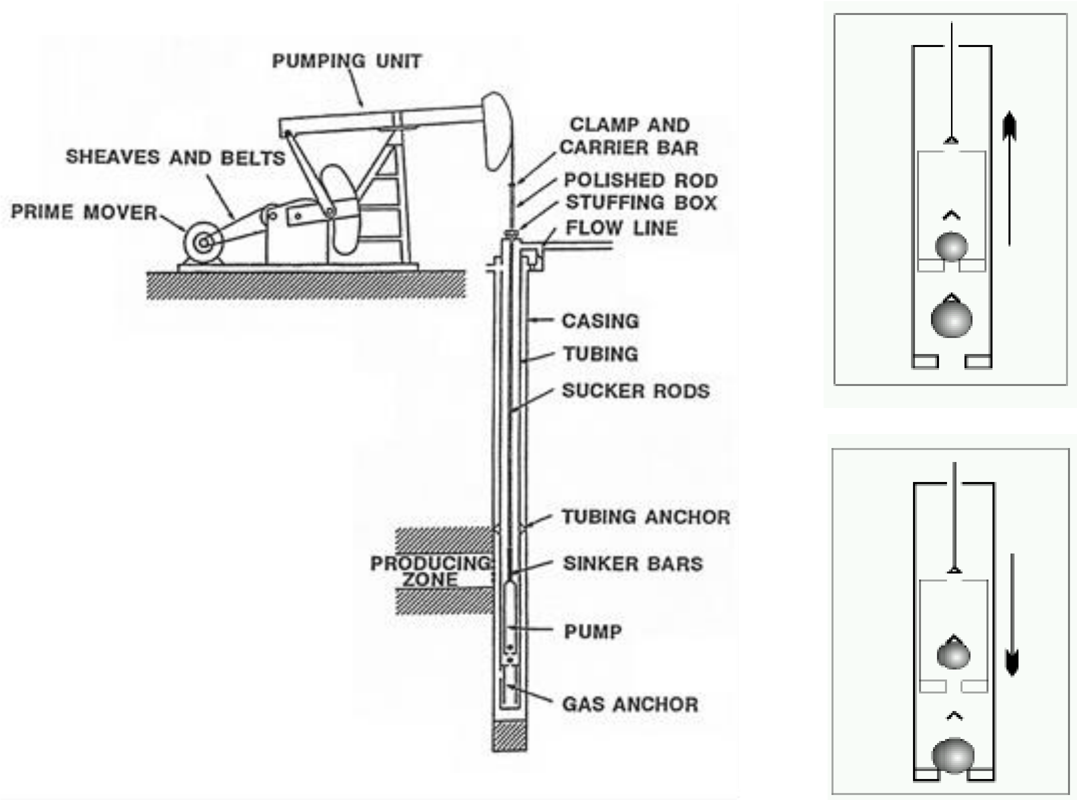

Figure 28: Basic elements of the Sucker Rod Pump. From ALRDC (2013).

Plunger Lift (PL)

It consists on a free steel piston inside the tubing string, which effectively separates the upstream form downstream fluids. The piston cyclically travels up the tubing carrying a column of liquids from downhole to surface, and then falls down the tubing again. With the piston at bottom, the well is automatically shut-off allowing the pressure downstream the piston to increase, until a certain value when the piston starts travelling up and evacuates the liquid out. When the piston arrive the wellhead, the production valve is shut-off again and the piston start falling down the tubing. The size and type of plunger is selected according to the specific applications: padded (expand/contract to tubing ID), solid/bar stock (constant OD), brush (flexible fibre material).

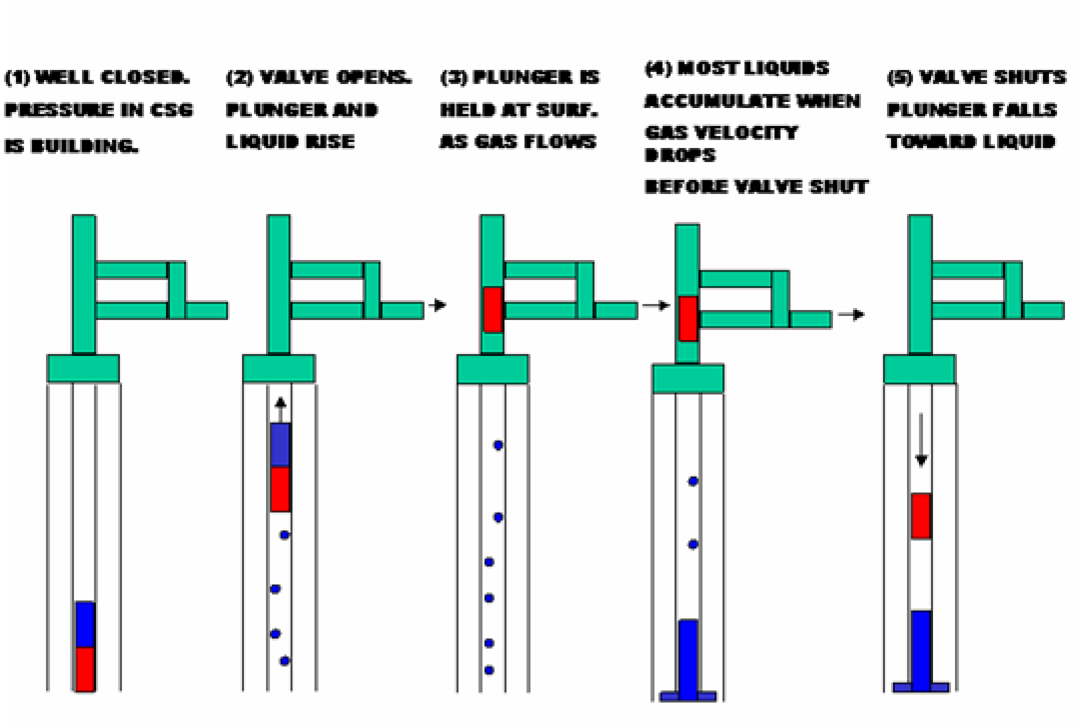

Figure 29: Basic elements and operation of the Plunger Lift. From ALRDC (2013).

Gas Lift (GL)

It involves the injection of high-pressure gas down the well, usually through the tubing-casing annulus, and entering the tubing through a gas lift valve. The injected gas mixes with the fluids at the tubing, lowering the weight of the fluid column, to allow the bottomhole pressure to force the fluid out of the wellbore. In a lesser extent, attaining a lighter fluid column also imply having lower pressure losses from fluid flow, too. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment.

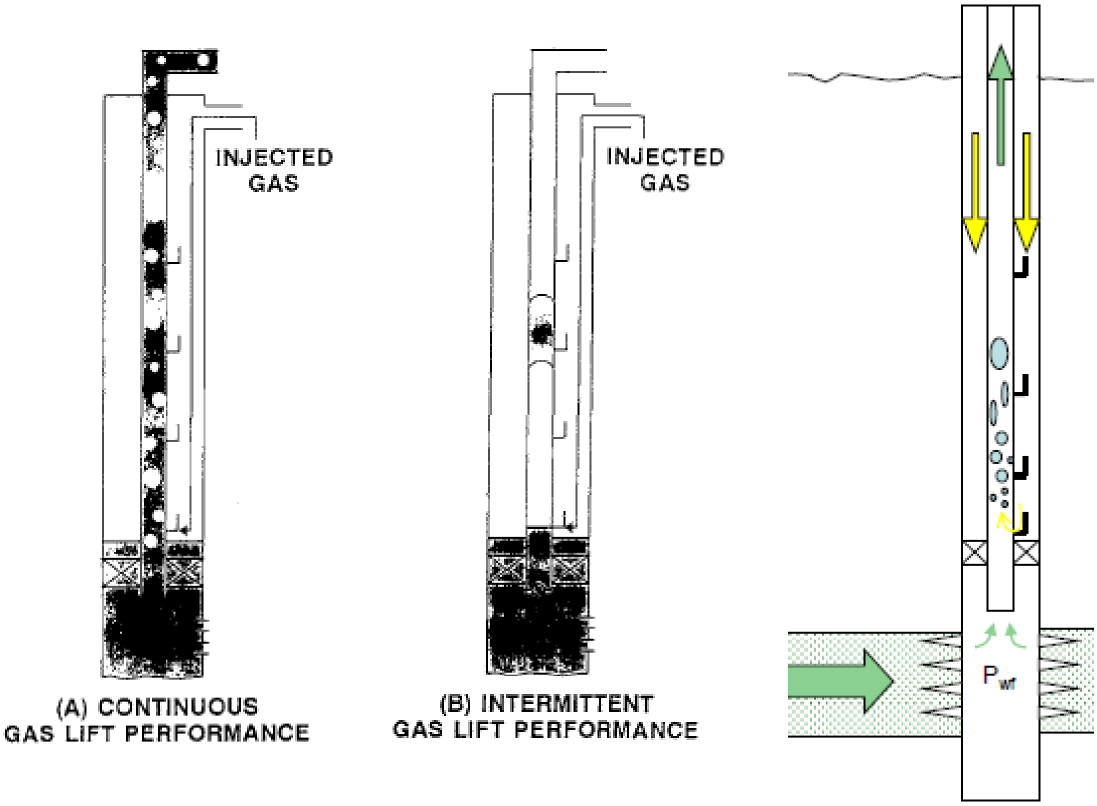

Figure 30: Basic elements and operation of the Gas Lift. From Clegg, J. (1993).

Electric Submersible Pump (ESP)

It is a positive displacement pump installed downhole that transfer kinetic energy to the fluid, by means of a downhole motor which moves a multi-stage centrifugal pump. The mechanical connection of the motor to the pump is isolated from the fluids with a seal-chamber section. A power cable, running from the surface to downhole and attached to the tubing, provides electric energy to the 3-phase induction motor. The motor-seal-pump string is attached as the bottomhole assembly of the tubing string.

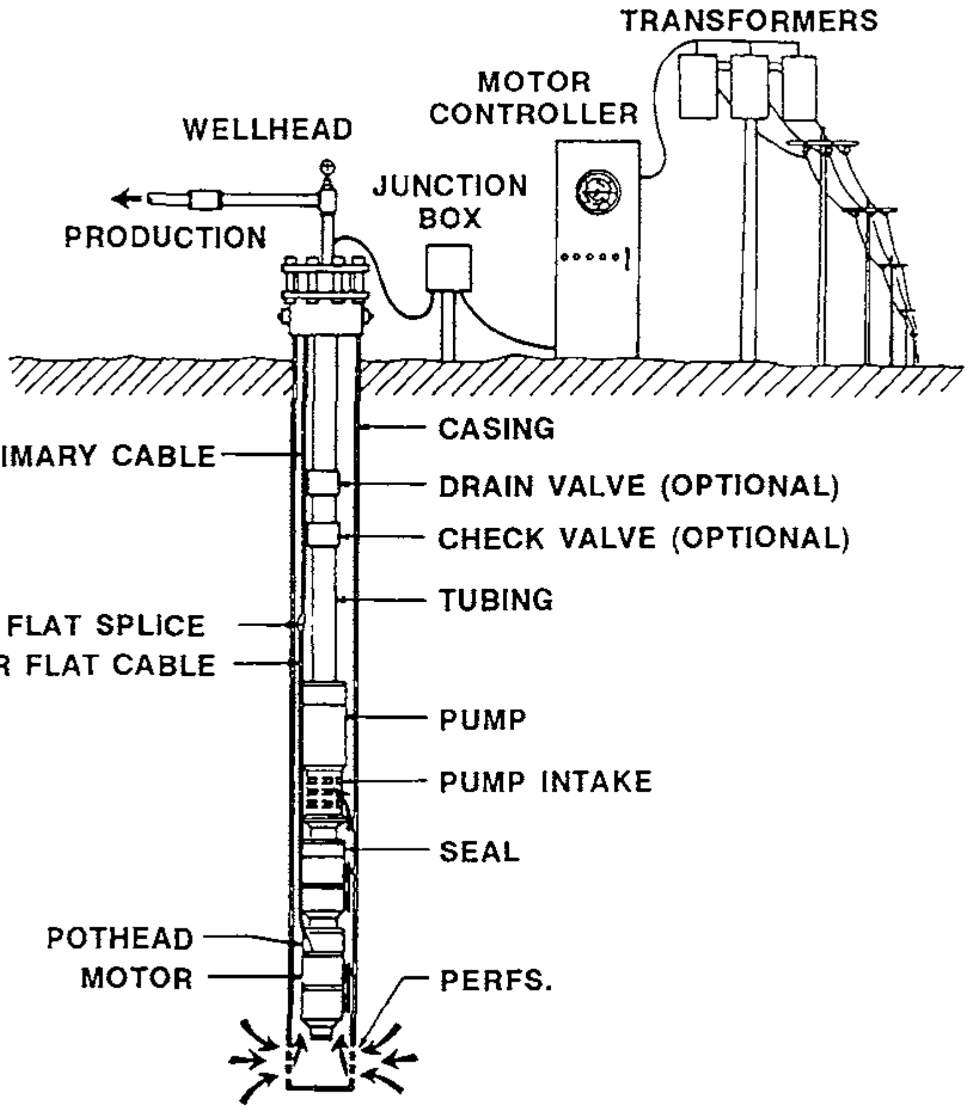

Figure 31: Basic elements of the Electric Submersible Pump. From Clegg, J. (1993).

Jet Pump (JP)

Consist of a subsurface pump powered by a high pressure (power) fluid that is pumped from the surface. The main types of hydraulic subsurface pumps are piston pumps and jet pumps. Jet pumps consist of a nozzle, operating under the "Venturi" principle: the power fluid is ejected through the nozzle transferring it kinetic and potential energy (high pressure) to the reservoir fluid, which in turn accelerates and comingles with the power fluid upstream of the nozzle. The result is a comingled fluid with higher pressure than the previous downstream reservoir pressure.

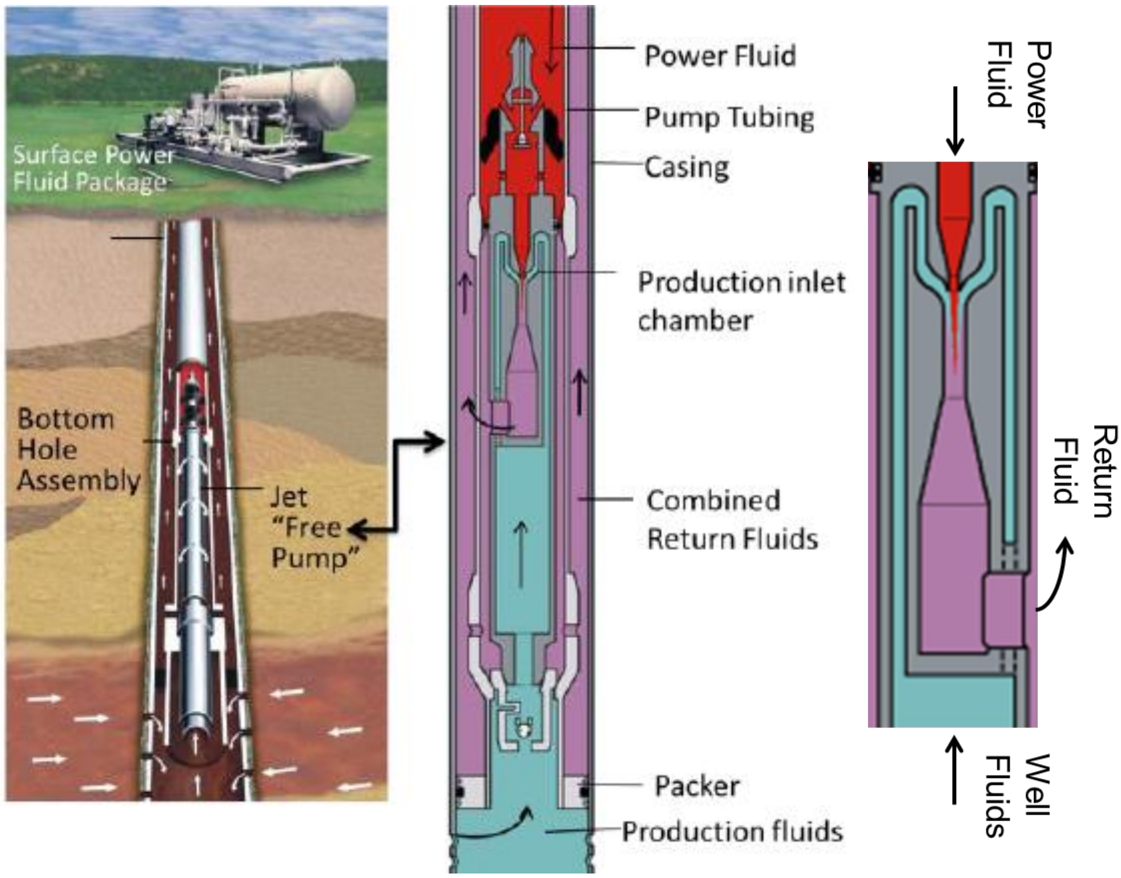

Figure 32: Basic elements and operation of the Jet Pump. From: ALRDC (2013) and Lane, W. & Chokshi,, R. (2014).

Progressing Cavity Pump (PCP)

A positive displacement pump installed downhole that comprise two basic elements: the Rotor and the Stator. The Rotor is the moving element, a helical piece of steel that is driven by a motor at surface, connected through a rod string. The Stator is the fixed element, a steel tubular housing with a bonded elastomeric sleeve of formed with a multiple internal helix matched suitably to the rotor geometry. The rotation of the Rotor into the Stator makes the fluid to go up through the spaces between these elements, and to gain pressure as it climbs up. Typically the Rotor is driven by a prime mover (engine) form surface, which transmits rotation downhole through a rod string, but some advanced applications use a down-hole motor to drive the rotor.

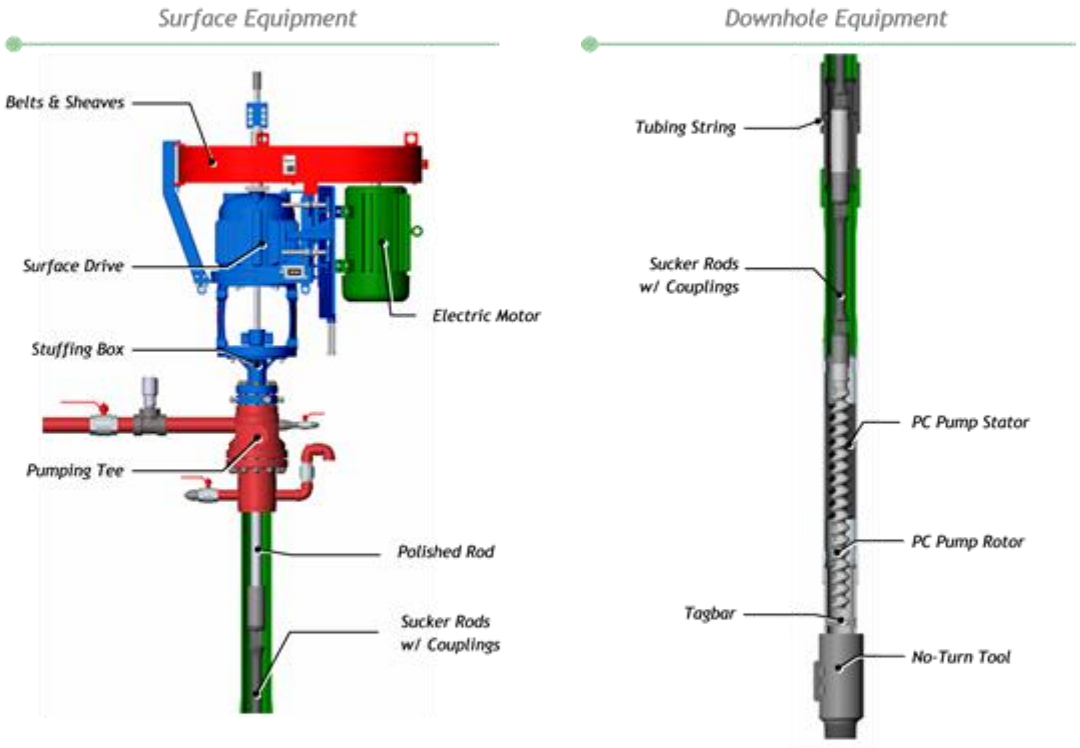

Figure 33: Basic elements of the Progressing Cavity Pump. From ALRDC (2013).

Foaming

Limited amounts of liquid produced in gas wells can be unloaded by mixing them downhole with surfactant, hence producing foam which yields a lower density fluid which can flow out of the wellbore. It is often used as the first deliquification attempt, because it is inexpensive to try. Surfactant can be introduced into the wellbore as regular soap sticks (dropped down the tubing from the wellhead), as batch or continuous treatment down backside with packer removed, or a more complex and controlled injection system through a capillary string lubricated systems (termed foam assisted lift).

Velocity string

It is a small diameter tubing string that is run inside the production conduit of the gas well (often coiled tubing), reducing the flowing area and hence increasing the gas flow velocity to surpass the critical value (i.e.: less than the critical velocity the liquids are no longer carried from the wellbore with the gas stream as small droplets).

Other unloading practices

For unconventional gas well, following unloading practices has been reported as a common approach for unloading the wells at flow-back (Nunez Pino, et al., 2016), just to evacuate the dense liquid column from the wellbore (fracturing fluids, proppant and reservoir fluids):

- Swabbing operations: a swab cup assembly is run down and up the tubing repeatedly to bring liquids to surface.
- Nitrogen lifting operations: N_2 (generated in-situ or imported) is pumped down the hole through coiled tubing, and mixed with the tubing fluids, dropping the overall density until the wellbore fluids are light enough to flow to surface.

An alternative to these practices is to install an ESP or JP as part of the commissioning of the gas well, using them as assisted flow-back and thereafter during the early drawdown period.

III.2 Selection of the System

The importance of artificial lift in the production of oil, and in a lower extent gas, is evident after noticing that most of the producing wells have installed some sort of those systems (Brown, 1982). While once it was conceived as a technology for mature production, currently the artificial lift system to be used at certain phase of the wells' life is considered and projected into the field development and/or field management plan, in order to define the production plan and to provide appropriate design parameters for the well configuration and surface facilities (Brown, 1982) (Clegg, et al., 1993).

Over the last decades, with the appearance of several possibilities for lifting liquids in oil wells and deliquifying gas wells, also several methods has been proposed on how to select the optimal artificial lift system when solving a particular case. The selection of a system rules out other alternatives, and as such, is usually a no-return decision because of the required investment to turn back to another alternative. Qualitative selection methods are based on the comparison between operating constraints of each method and the operating parameters for the particular situation, and based on the experience and reported performance of the methods. Quantitative selection methods also grounds the decision on operating issues, ruling out unfeasible methods and ranking the rest according to the adaptability to the situation, including an economic assessment of each feasible alternative (Valbuena, et al., 2016).

Nevertheless, it has been advised that the selection process is not only a matter of applying strict rules for decision making, but also biased by the operating personnel opinion (Clegg, et al., 1993). It is possible that most popular methods within a basin or operator would have a favourable opinion, establishing an actual barrier for newcomers.

The selection of a particular method is usually performed on a field scale basis and should be planned at the same time as drilling, completion and surface infrastructure design (Clegg, et al., 1993) (Lane & Chokshi, 2014). There are information requirements in terms of fluid properties and reservoir behaviour for the artificial lift selection process, which are collected during exploration and appraisal for the field development plan, too, but of course the selection would very much benefit from actual production data.

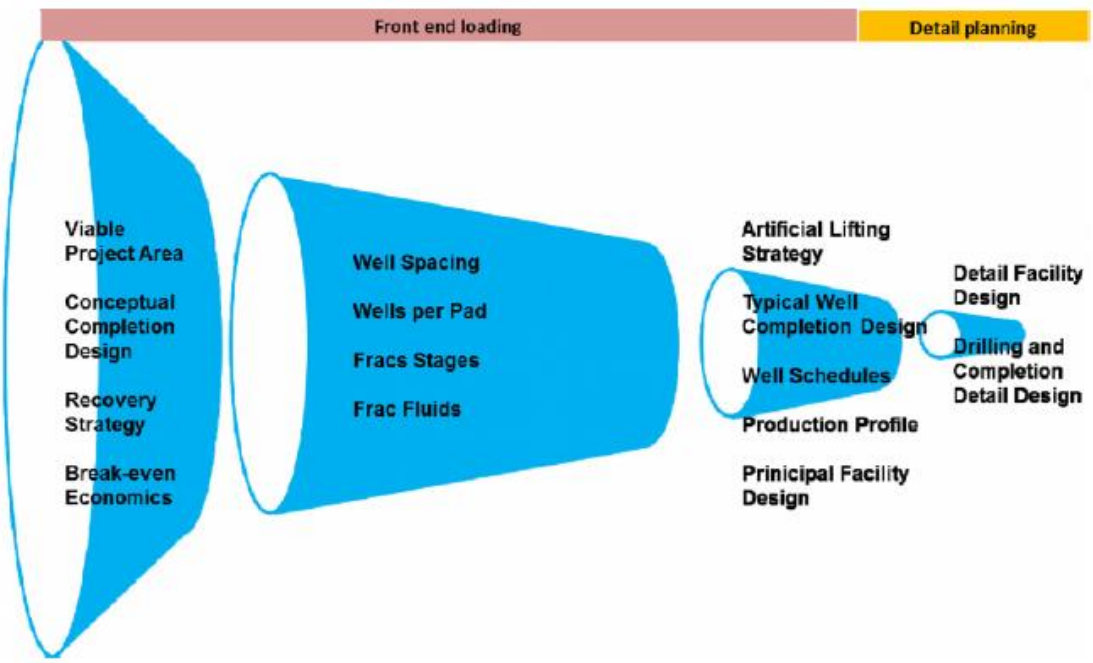

Figure 34: Decision sequence for tight and shale oil assets, after Kahn, N., et al (2014).

As defined by Khan, N., et al (2104), the appropriate timing for the design and selection of the artificial lift system for unconventional reservoirs, within the field development project, comes after the well configuration and has been defined, as shown at Figure 34.

There are some basic well parameters, like the reservoir fluid characteristics, the expected gas and liquid flowrates, the depth of the target, and well geometry including casing/ tubing size, that are key decision criteria in the selection process. At this first selection step, certain artificial lift alternatives are eliminated because actual well characteristics are beyond their operational envelopes (Valbuena, et al., 2016). Sometimes operating at extreme conditions, even away from the known practical limits, would be feasible by incorporating modifications to the technology, taking remedial actions, installing additional devices, or accepting a higher failure frequency for a certain artificial lift (Clegg, et al., 1993).

Reliable access to certain resources at a reasonable cost, i.e.: electric power and/or gas, sometimes rule out some of the methods during selection process. Sucker rod pumps and PCP are among the most efficient methods in terms of horsepower efficiency, attaining more than 50% of efficiency, while gas lift and jet pumps are at the opposite side (Clegg, et al., 1993). Further field and surface constraints, like the noise level, space requirements or occupancy, and supervision requirements, would have a major impact on the selection process, as well.

The operational limits, advantages and disadvantages of each system, as fully described in the literature, are not listed herein, but taken as an input for the discussion at section 5.

At the end of the selection process, a short list of feasible artificial methods is to be evaluated according to their expected economic performance. Main economic aspects to be compared among the methods are the required investment for installation and commissioning (capital expenditures or ‘Capex’), the cost for operation including maintenance and repair (operation expenditures or ‘Opex’), and the cost of deferred production during interventions. Those figures, together with the expected net revenues derived from the artificial lift, are necessary to generate a cash flow model from which to calculate economic performance indicators: the Net Present Value (NPV) of the artificial lift project and the Payback period. Uncertainties associated usually with oil and gas prices, Opex (including failure frequency), and production figures, should be reflected in the economic evaluation, by providing a range of deterministic indicators (average and most optimistic/ pessimistic), or by performing a stochastic evaluation.

Artificial lift does not have a direct effect into the reservoir, which will exhibit a characteristic Inflow Performance Relationship (IPR), a correlation of pressure vs production rate vs which varies in time according to the reservoir pressure, fluid characteristics, and permeability. At a certain time, the reservoir will deliver fluids to the wellbore following it characteristic IPR curve at that time. Several authors has reported the long term transient behaviour of unconventional reservoirs, and the rapid declining rates in natural flow, giving rapidly changing IPR curves (conventional wells usually attain the semi-steady state behaviour early in the well life, and exhibit less changing IPR with time). On the other side, the direct effect of artificial lift systems is on the wellbore fluids, allowing a higher drawdown than natural flow by reducing downhole pressure or wellbore fluids density. As such, each system will exhibit a characteristic Vertical Lifting Performance relationship (VLP), which in turn depends on the system performance, the wellbore fluids characteristics and the well configuration. The effect of different artificial lift systems on the same well can be sketched after IPR characteristic curves of tight wells, after Kahn, N., et al (2014), and VLP characteristic curves for natural flow, sucker rod pumps, jet pumps, gas lift and electro submersible pumps, after Brown, K. (1982). The IPR and VLP are sketched at Figure 4, showing interesting conclusions:

- While natural flow would be feasible at early times of the unconventional wells, at a few weeks or months when IPR has drastically changed, production becomes unstable until a no-flow condition.
- ESP will attain the highest drawdown and deliver relatively higher flowrates than other systems, while SRP is on the opposite situation (but delivering more than natural flowing). Nevertheless, this is a generalization of the VLP behaviour under different systems.
- At the early times of the unconventional well the later effect on production rate is significant, at some weeks or months of production, the extreme change in IPR anticipates not much production rate gain from the different artificial lift systems.

Appendix IV: Case study of tight & shale fields

Certain tight and shale fields in Neuquén basin, that have gone beyond exploration and currently are at a pilot or development stage, have been fairly described in the technical literature. In order to identify production technology trends, a summary of selected tight and shale fields in the basin has been performed as follows. Although not much information is provided in literature from those fields regarding artificial lift, which description is much concentrated on fluid and reservoir characterization, and stimulation optimization, some interesting reservoir and production technology issues, which are drivers for artificial lift selection, have been identified.

As far as possible, the information from literature review was complemented with and checked against production data, showing very good agreement. Unfortunately, not much relevant literature was identified regarding other interesting tight and shale fields in the basin.

Each field description contains a location map, a description and a summary of main production data: number of wells, oil and gas production. When available from literature, typical well architecture and completion is provided, as well.

Three fields were selected because of their importance in terms of production and number of wells (development stage), the availability of information from literature, and taking into account possible differences in production technology approach among operators.

Cupén Mahuida: Tight Gas Lajas

Information from the Cupén Mahuida field was collected from Licitra, D.T, et al (2012) and from Wagner, F., et al (2016), compiled with and checked against reported production data.

Cupén Mahuida field is located at the SW of the Loma La Lata – Sierra Barrosa area, one of the major gas suppliers in Argentina. On 2001 some development wells were drilled to produce from deeper gas targets (volcano-clastic reservoirs, naturally fractured), but in 2008, four wells were drilled and three former production wells were repaired to produce from tight Lajas Fm. A massive development launched in 2013, followed by pilot infill drilling in 2015.

Reservoir and Fluid characterization:

- Comprise a four-way closure anticline elongated E-W, associated with the uplift of the Huincul High, in particular to a large inverse fault from the basement with E-W orientation and dipping to the S. A pattern of faults oriented N-S has been recognized, which produce lateral discontinuity and compartmentalization of the reservoir.
- Lajas Fm. thickness up to 3,300 ft (1,000 m), comprising from fine to coarse sands, up to conglomerate grainsize, intercalated with claystones. Three members have been recognized: Upper Lajas is a deltaic-fluvial environment dominated by tides and waves, Mid Lajas and Lower Lajas are associated with a deltaic plain, distributary channels and a delta

front. Average permeability grows from base to top (1 µD, 10 µD and 100 µD, respectively).

Production data:

- As of October 2016 there were 173 active wells, mostly targeting Lajas Fm. as the main reservoir formation (91%), for the production of 189 MMscf/D (5.3 million m^3/d) of gas. Total production of water is 23,352 B/D (661 m^3/d).
- A choke management strategy has been implemented for the natural flowing period of the wells, by gradually increasing the orifice size, with much care not to impose irreversible effects into the well productivity and recovery factor. Only 4% of the wells report plunger lift or sucker rod pumps.
- In 2015 a pilot infill campaign was carried out; simulation modelling has proved that infill wells have increased the drainage area effectively.
- The first horizontal well was drilled and completed in early 2016, with a lateral section of 2,625 ft (800 m) and 7 fracture stages. Anomalous high water production at flow-back was reported for this well (formation water).

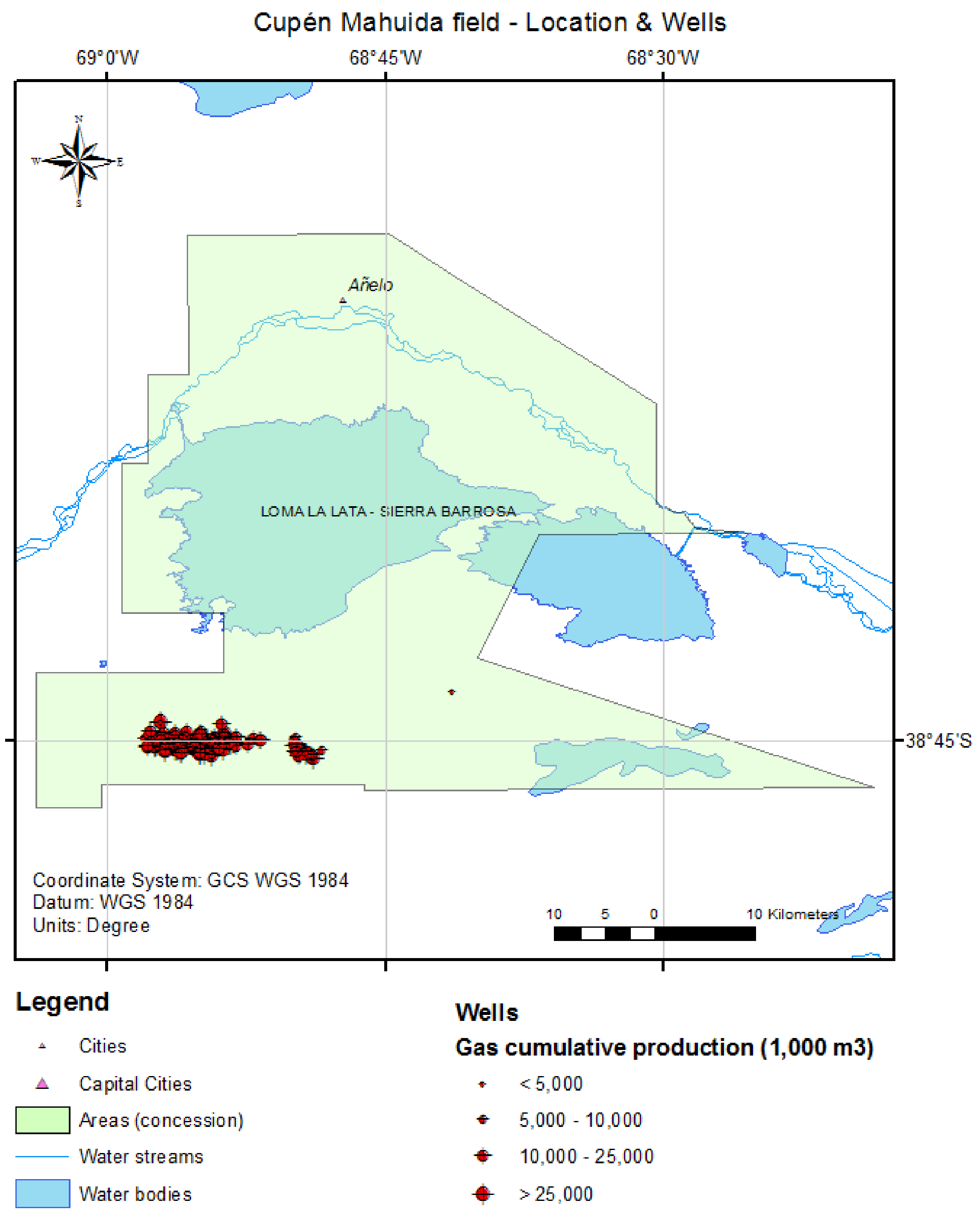

Figure 35: Map of Cupén Mahuida field.

Río Neuquén: Tight Gas Lajas and Punta Rosada

Information from the Río Neuquén field was collected from Barbalace, F., et al (2014) and SEMH (2014), compiled with and checked against reported production data.

It is originally a gas producer area from conventional reservoirs of Lotena Fm. and Mulichinco Fm. Although a few tight wells have been producing for around 10 years (Masarik, 2014), more comprehensive wells were drilled and stimulated to produce from both tight sands of Lajas Fm. and Punta Rosada Fm. around 2012, and extensive drilling proceeded last 2 years.

Reservoir and Fluid characterization:

- The reservoir unit of Lajas Fm. is a massive sandstone with a net thickness of 65 – 150 ft (20 – 45 m), while Punta Rosada Fm. comprise very close thin lenticular packages of 7 – 15 ft each (2 – 5 m), laterally discontinuous.
- Reported depth of Punta Rosada Fm., from SEMH (2014), is 9,200 – 12,800 ft (2,800 – 3,900 m), but possibly indicate the reservoir top, and is not taking into account the underlying drilled and completed interval of Lajas Fm. Actual well depth from production reports generally exceed 12,500 ft. At this field the reservoir gross thickness can reach 3,300 ft (1,000 m), with a net interval of 10-15%, and usually low porosity of 2-12%.

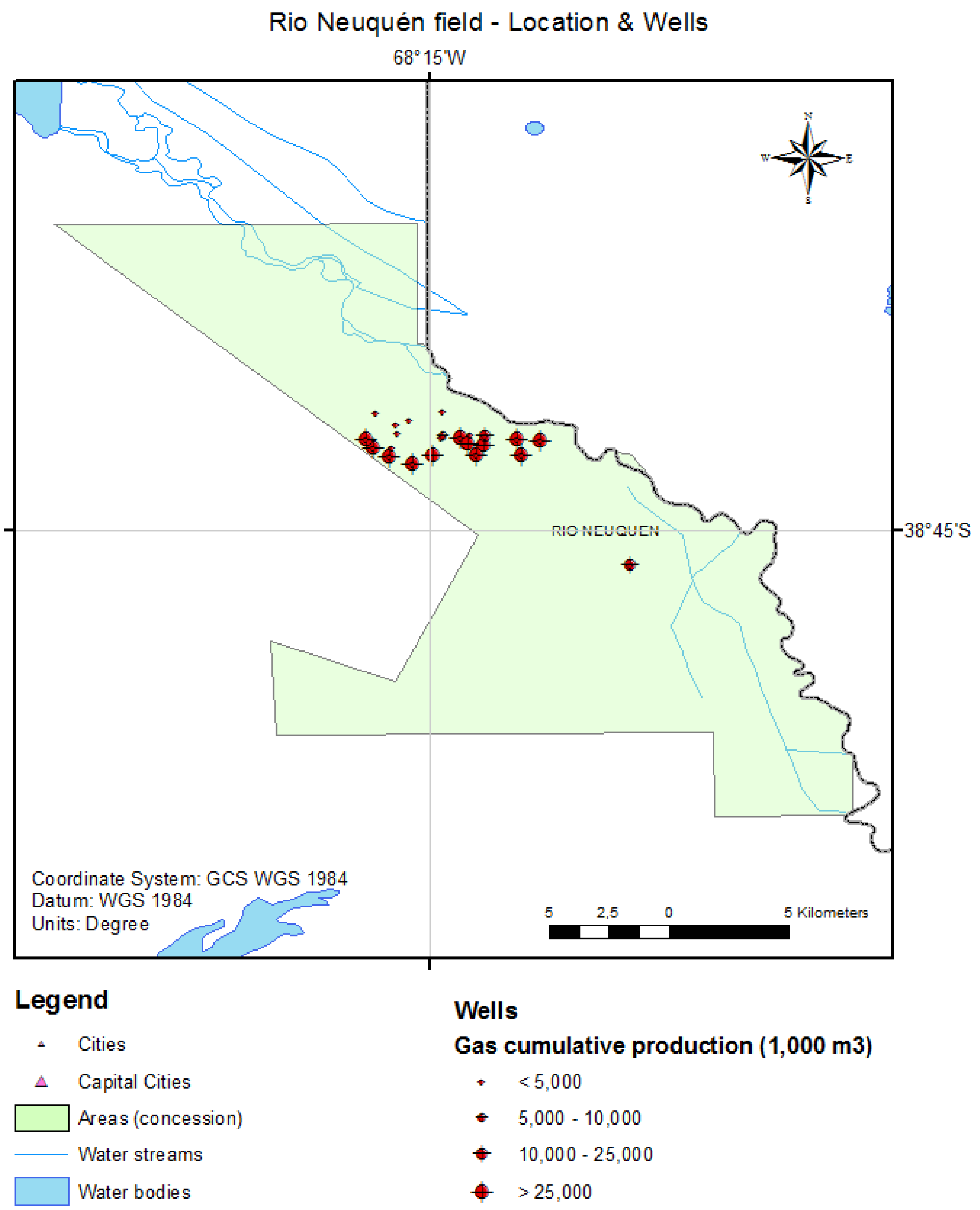

Figure 36: Map of Río Neuquén field.

Production data:

- As of October 2016 there were 47 active wells, mostly targeting Lajas Fm. (40%) or Punta Rosada Fm. (55%) as the main reservoir (the report does not discriminate when more than one reservoir unit is produced), for the production of 95 MMscf/D (3 million m^3/d) of gas. Total production of liquids is 3,550 B/D (560 m^3/d), but a single well contributes with almost a half of that volume in oil or condensate.

- Production of commingled gas flow from Lajas Fm. and Punta Rosada Fm. is through a 4'' monobore wellbore. It is reported that a tubing-less completion prevent from problems with tools downhole, and allow the installation of rotating and economic terminations not requiring rig equipment (Barbalace, et al., 2014).
- At completion, the wells are stimulated at both reservoirs consecutively, by different fracturing techniques to optimize completion operations, evolving from initial reported 7 – 9 fracturing stages (Barbalace, et al., 2014), to currently 12 - 16 stages for net intervals of 260 – 400 ft (80 – 120 m) (SEMH, 2014).

Loma Campana: Shale Oil and Gas Vaca Muerta

Information from the Loma Campana field was collected from Martinez, J.F., et al (2015), Rimedio, M., et al (2015), and from Suarez, M., et al (2015), compiled with and checked against reported production data.

It's probably the most relevant unconventional development in Neuquén basin so far, in terms of number of wells and production, located in an area of 395 Km2, in the west central region of the basin. The first shale well was drilled in 2010, and from 2014 a 'factory drilling' model was implemented, mainly using a 4, 6 or 8-well pad to drill vertical wells from a single location, at 23-acre spacing to maximize drainage area. The pads were constructed in long rows, to accommodate simultaneous operations: production, stimulation and drilling.

Reservoir and Fluid characterization:

- Production of shale oil and gas from Vaca Muerta Fm., with a reported thickness at the field of 330 – 1,150 ft (100 – 350 m), and the top of the reservoir located at a depth of 9,200 – 9,850 ft (2800 – 3000 m). Comprise a gently dipping monocline oriented NNE cut by a multiple set of faults reactivated from pre-existing basement structures.
- Matrix porosity: 0.1 – 10 µD. A lower member with higher TOC, associated with a condensed section, has been described by several authors. It is an overpressured reservoir with an average gradient of 0.9 psi/ft.

- Fluid composition varies across the field, light oil 38 – 55 °API, medium to high GOR of 505 – 11,230 scf/bbl (90 – 2,000 m^3/m^3).
- A 'Sweet Spot' has been identified and developed in the NW of the field: thicker pay interval, higher porosity, presence of a natural fractures network, and lighter oil (> 50 °API) than other areas.

Production data:

- As of October 2016, reported production is 29,416 B/D (4,677 m^3/d) of light oil and 55 MMscf/D (1.6 million m^3/d) of dry and associated gas, from 525 wells at Vaca Muerta Fm. (90%), but also at Quintuco Fm. as the main producing units.
- Initially, vertical wells with a few hydraulic fracturing stages were drilled and completed, beginning with exploration and pilot development. Currently, turning to horizontal wells with a typical lateral length of 3,940 ft (1,200 m) and 15 fracture stages.

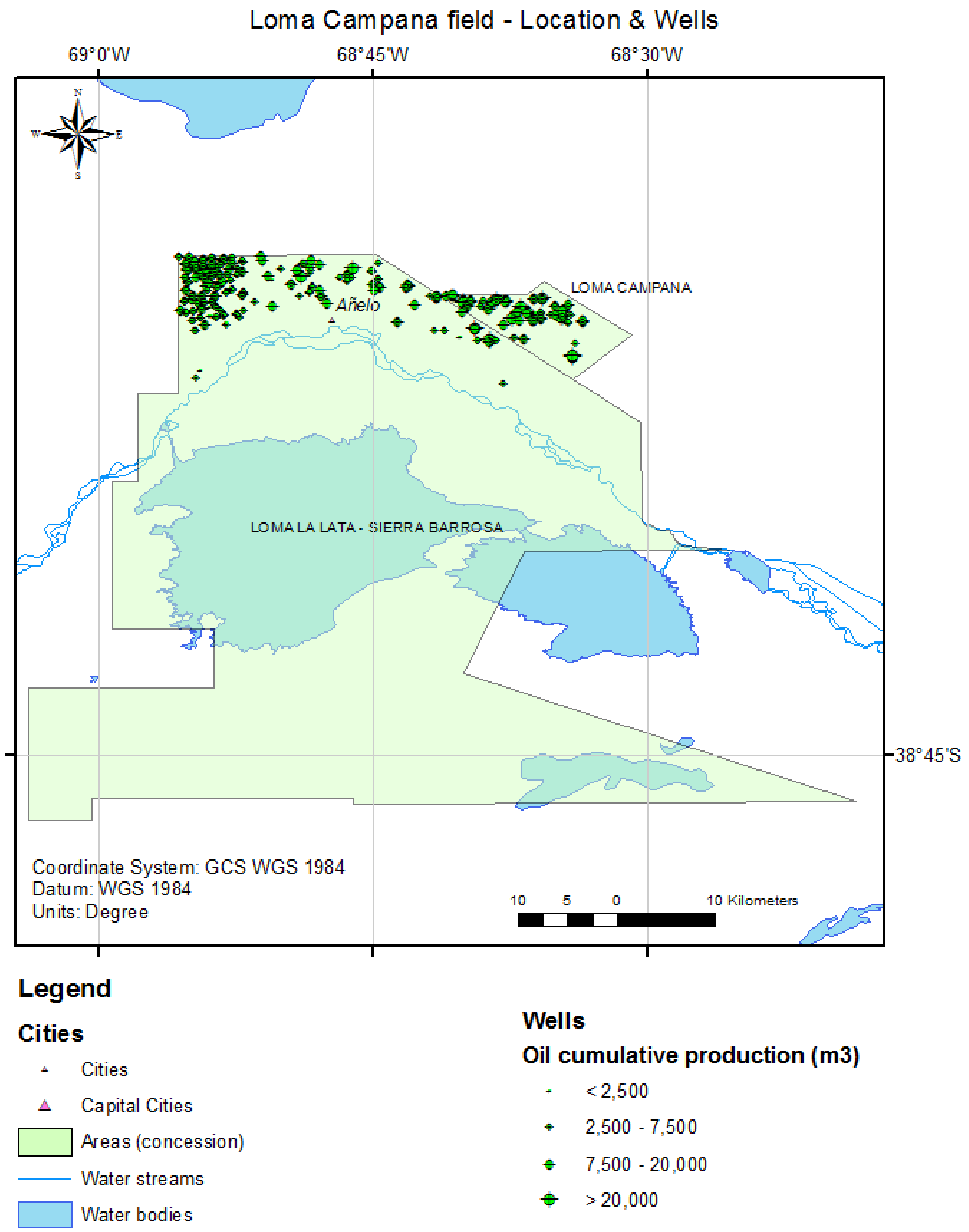

Figure 37: Map of Loma Campana field.

Appendix V: Economics

The aim of this section is to estimate the total cost of artificial lift (capital expenditures 'Capex' and operational expenditures 'Opex') on a reasonable scenario of development of tight and shale resources in Neuquén basin. It does not include the analysis of enhanced production from each artificial lift system, or deferred production while the wells are intervened, but still is a valid estimation. It is based on a published drilling and production forecast after Gomes, I. & Brandt, R. (2016), and on reference costs of artificial lift from literature (ALRDC, 2013) (Oyewole, 2016) (Rehman, et al., 2011), checked with local providers.

The development scenario is based on an exponential growth of tight and shale wells for the period 2017 – 2030, predicting 9,800 wells to be drilled and completed, and 73,000 million USD to be invested on that period (D&C Capex, including exploration and development, completion, facilities and gathering system costs). Additional investment in this scenario, including 25,000 million USD in natural gas transmission and distribution and others not specified, predicts a total investment of 250,000 million USD in the exploration and production sector during the period (including tight and shale development). Figure 38 summarize the main figures from this forecast.

Two different extreme scenarios were explored to forecast the artificial lift expenditures during this period: (1) current lifting approach; i.e.: after 1 – 1.5 years of natural flow, plunger lift is installed in 51% and sucker rod pumps in

24% of the wells; (2) a more intensive and diverse use of artificial lift systems; i.e.: all wells are flowed-back with jet pumps for a short period (days), gas-lift (50%) or jet pump (50%) lift the well for around 3 years, and at the late drawdown period sucker rod pumps are installed. This is one of the possible artificial lift approaches according to Lane, W. & Chokshi, R. (2014). These extreme scenarios reflect a “business as usual” case (1) and a dramatic production technology change case (2). The most probable artificial lift approach in the future may exhibit something in between, including a combination with other systems, but it is expected that the expenditures will distribute within the estimated extremes.

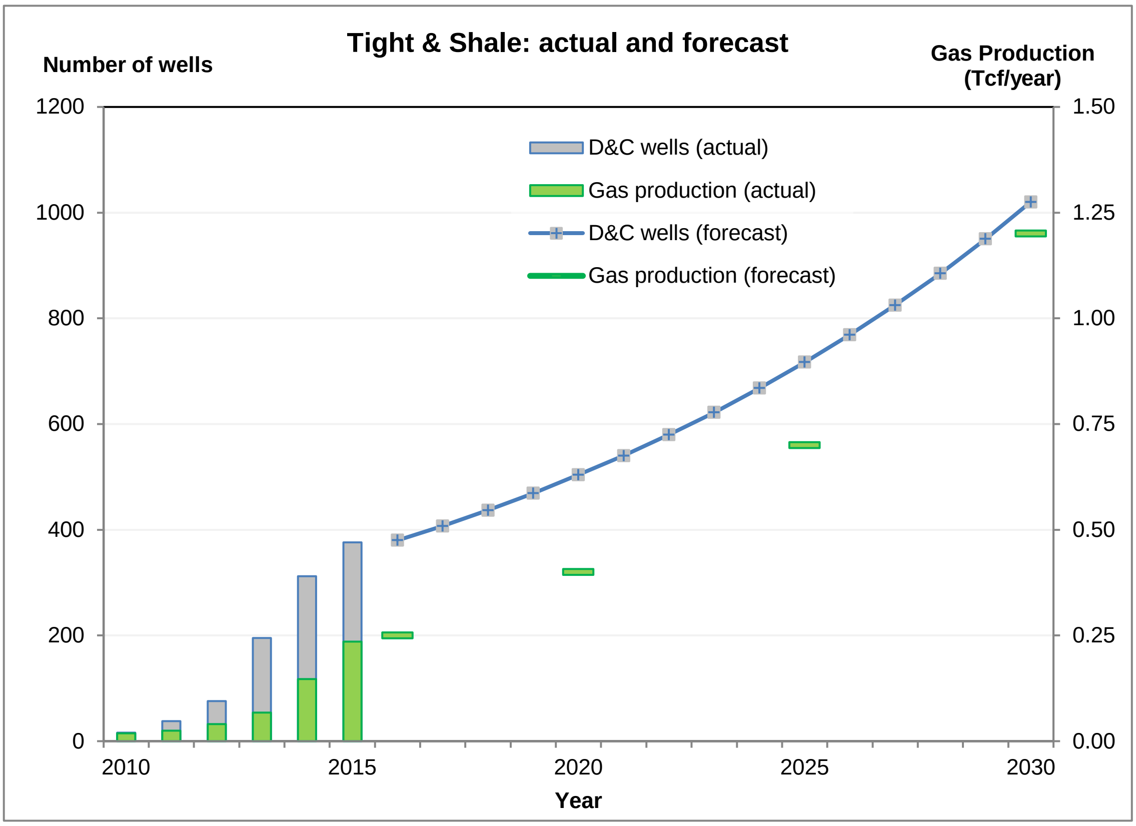

Figure 38: Development scenario 2017-2030 after: Gomes, I. & Brandt, R. (2016).

Table 2 shows the assumed artificial lift expenditures for based on literature and checked against artificial lift providers' judgement. The results from this exercise are shown in Figure 39 and Figure 40, and exhibit a wide range of 3,000 to 7,000 million USD in total expenditures to be required by artificial lift installation and operation during 2017 – 2030 (corresponding to the scenario 1 and 2, respectively).

Artificial Lift System	Capex (USD)	Opex (USD/y)
Sucker Rod Pump	290,000	15,000
Jet Pump	250,000	15,000
Gas Lift	300,000	15,000
Plunger Lift	10,000	5,000

Table 2: Estimation of artificial lift systems Capex & Opex.

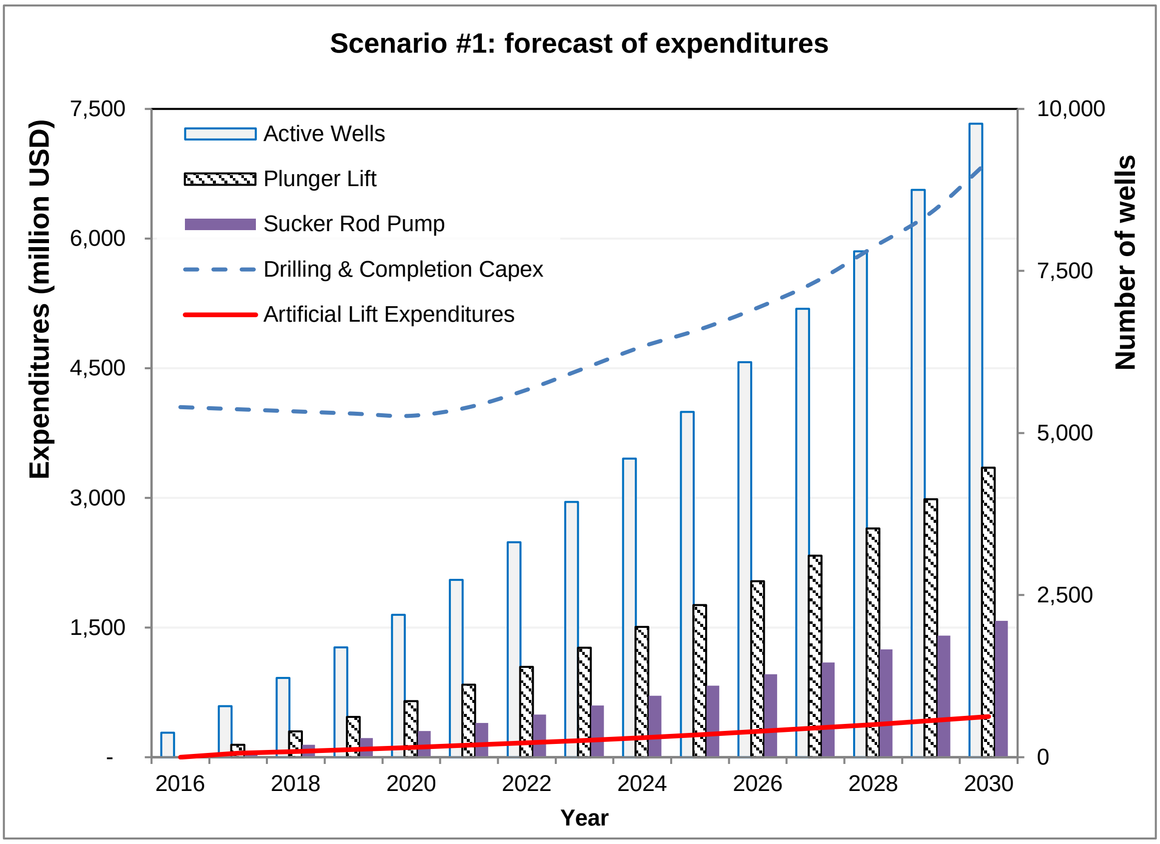

Figure 39: Forecast of artificial lift expenditures 2016-2030 (Scenario #1).

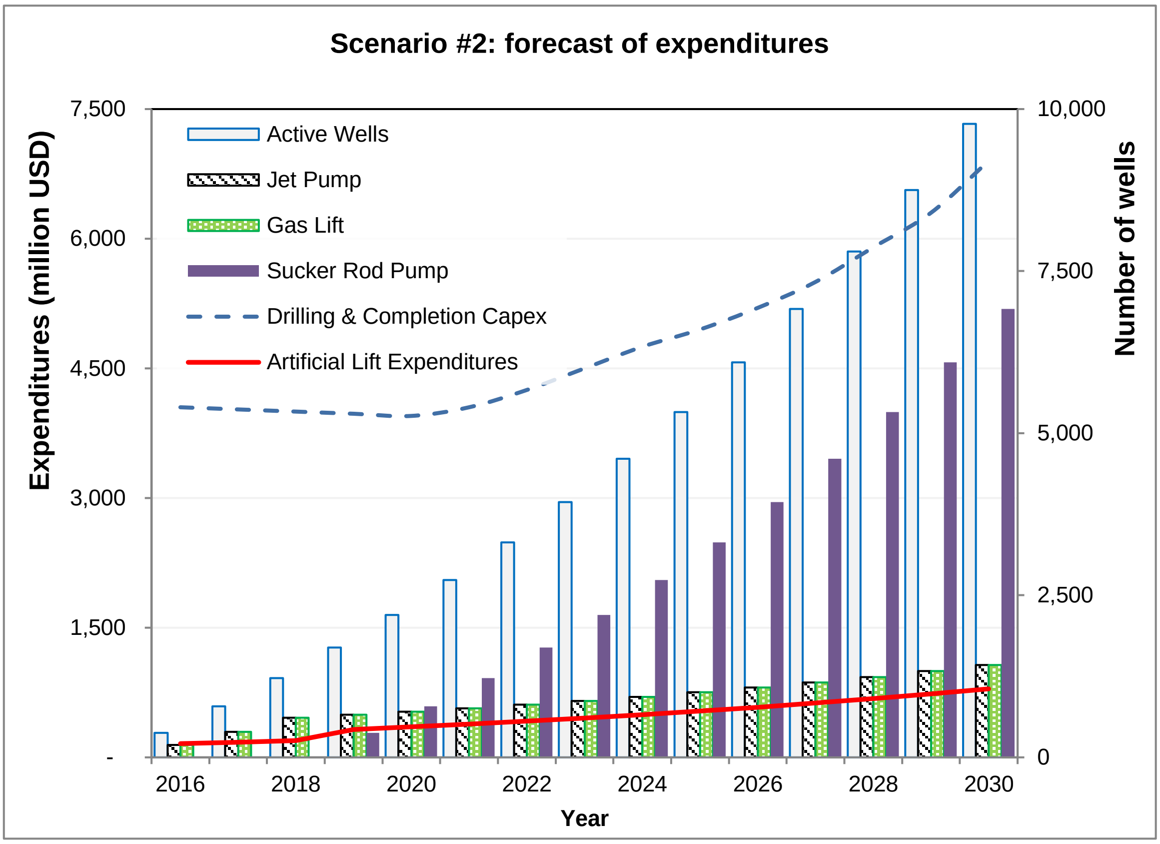

Figure 40: Forecast of artificial lift expenditures 2016-2030 (Scenario #2).

According to this estimation, artificial lift sector represents a minor fraction of the overall expenditures to be allocated for shale and tight development in Neuquén basin, but still a large amount in absolute terms. At the same time, it is expected a significant economic impact of artificial lift in attaining larger recovery factors from those resources.

Appendix VI: Survey to providers

The list of providers to survey was prepared with the aim to grab information and the opinion from artificial lift experts at service companies. In order to focus the scope of the survey, only those providers of artificial lift for Argentina and South America were surveyed, and the list was balanced so that all main artificial lift systems (as described at Appendix III) are included into the list.

Question 1	Wells for the production of unconventional reservoirs may exhibit additional challenges concerning artificial lift than conventional: large decline rates w ith variable production rates, solids from flow -back, complicated w ell geometry (large horizontal and/or dog-leg severity), and high gas-liquid ratio . Taking that into account,
a.	Has your company developed specific artificial lift solutions for tight and shale w ells?
b.	Do you identify any trend in the use of artificial lift systems for unconventional resources in North America, considering their particulars (i.e.: shale vs tight, oil vs gas, early vs late w ell's life?
Question 2	The Neuquén basin has been termed as the most prospective province outside North America for unconventional development, w ith several proven and under development, and other prospective shale and tight resources. From your perspective,
a.	How artificial lift solutions w ould impact into the development of these resources?
b.	Are you w orking on any plan or project regarding artificial lift applications for the unconventional resources of Neuquén basin?
c.	At this early stage of development, is there any lesson learned or guideline (of artificial lift) for the production of unconventional w ells in the basin?
d.	Please identify w hich artificial lift system/s w ill better adapt to the challenges of developing unconventionals in the basin.
Question 3	References
a.	Would you recommend review ing any reference to gain a better insight, or to contact any colleague to discuss the issues abovementioned?

Table 3: Survey questionnaire.

Some of the providers commercialize different systems, and do have international operations and experience in lifting tight and shale wells in North America. Table 3 shows the information requested to the providers, divided into general knowledge regarding artificial lift applications for tight and shale wells, specific questions regarding unconventional resources in Neuquén basin, and a final request of additional information about those issues. A questionnaire (both in Spanish and English) was sent by e-mail to 14 experts from 8 service companies, and e-mail and/or telephone communications were established afterwards with the experts.

A reasonable level of 75% of participation from the list of providers was obtained. This group of providers market all the artificial lift methods assessed, hence a fair spectrum of opinions was collected. Despite the fact that few of them have worked specifically on tight and shale wells in Neuquén basin, all of them are aware of the issue and it challenges, and most of them have experience in lifting unconventional wells in North America.

Communication with the experts returned useful information, which reasonably agrees with information from literature and production database. It also delivered useful information and personal insight regarding current practices and possible future trends of artificial lift applications.