DECISION MAKING CRITERIA AND CHALLENGES IN RECIPROCATING ROD PUMP RAMP-UP

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ABSTRACT

Reciprocating rod pumps (RRP) have globally shown that with longer strokes increased productivity and reduced operational costs can be achieved over that of a progressive cavity pump (PCP) in clean to moderate solids producing wells. This has also been extended to suggest that with the right equipment mean time to failure can be increased. This information has been pivotal in a large-scale change for Origin Energy Limited's fields under the Australia Pacific LNG Pty Limited (APLNG) joint venture with ConocoPhillips Company and Sinopec Australia Pty Limited to address the hypothesis that increased RRP completions will, increase mean time failure past current run lives and reduce the flowing bottom hole pressure for optimal gas production. To do this an economic analysis was undertaken to understand based on cost, what units are applicable to what wellsites. This included a detailed analysis of the inputs and outputs with our Global subject matter expert (SME) partners from ConocoPhillips Company and an economic build-up based on their and local experience. The analysis led to the utilisation of tower units and beam units in conjunction with Linear Rod Pumps (LRPs) and lead to the first successful installation of a tower unit in Australia with a significant ramp of RRP over the near term across three main surface drives. Technology trails, both surface and subsurface, have also been undertaken underpin our current understanding and reach towards goal production and failure statistics. Vendor support and engagement in Research and Development (R&D) projects and continual improvement has also greatly benefited our overall result. Challenges were faced in supply chain and logistics, availability of parts and servicing and the ability to quickly pivot using new information for optimal performance. A large-scale ramp-up has many challenges that have provided opportunities to learn, innovate and implement changes that have resulted in increased performance of the technology and wells.

INTRODUCTION

Australia Pacific LNG Pty Limited (APLNG) operates one of the worlds largest coal seam gas (CSG)-LNG projects which consists of ~3000 wells spread across western Queensland, Australia. Origin Energy Limited is the upstream operator with its joint venture partners ConocoPhillips Company and Sinopec Australia Pty Limited. The wells are spread across 2 basins, the Bowen and Surat, and are predominately vertical. These wells are connected via gathering networks with both gas and water transported respectively to gas processing facilities (GPF) and water treatment facilities (WTF). Gas from the GPF's across the fields, as seen in figure 1, is transported up the 530km high pressure gas pipeline into the LNG facility on Curtis Island.

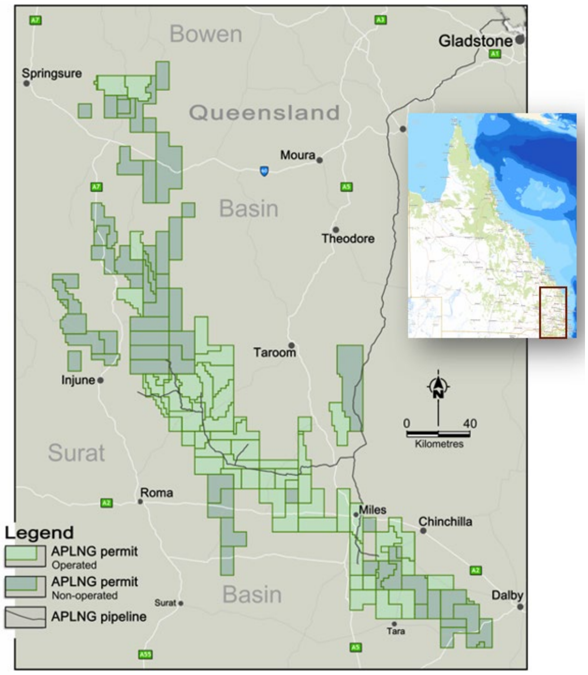

Figure 1: APLNG fields and pipeline to LNG facility

The primary artificial lift system (ALS) for the early development phases was progressive cavity pumps (PCPs). These have a wide variety of operating conditions and have a lower cost of implementation over other ALS. Both tubing installed PCP and insertable PCPs installed on pump seating nipples (PSN) have been deployed and in a CSG wells with successful dewatering in early life production. Due to the requirements to pump off the wells and reduce the flowing bottom hole pressure (FBHP) as far as possible to increase the desorption of gas from the coal matrix. Two main issues have been observed, solids production and gas interference [1, 2]. Solids production poses a larger challenge, solids range from coal fines to water sensitive interburden and a range of mechanisms such as completion design, formation stabilisation and PC pump geometry have been used to increase the mean time to failure (MTTF) of PCPs [2, 3].

However, as the well fleet ages and water declines a larger challenge has been faced regarding a PCPs ability to pump smaller volumes of water leading to reductions in MTTF. This is increasingly evident when water rates drop below 50 barrels of water per day (bwpd). At these rates if the fluid is drawn down to at or below the pump intake there is the potential for gas ingress and swelling of the elastomer materials in the PCP, in turn this can lead to premature failure. Additionally, if the PCP is situated above the bottom coals in the wellbore and the FBHP reduced sufficiently, gas ingress can be observed leading to damage and efficiency loss in the PCP [1]. At the same time the economics are declining and the required OPEX increases due to the wear and tear on equipment and increased workover requirements. Thus, the hypothesis is that increased reciprocating rod pump (RRP) completions will, increase MTTF past current run lives and reduce the flowing bottom hole pressure for optimal gas production where solids are manageable. RRPs have the advantage over PCPs and Electric Submersible PCPs (ES-PCP) of pumping off, when managed with automation, to avoid damage to the downhole equipment which enables a further reduction in the FBHP [4]. Over the last many years RRPs have been used as the ALS system for some wells among the fleet. These have been operated via Linear Rod Pumps (LRPs) and a small number of Beam Pumping Units (BPUs). The LRPs in our fleet are limited to a maximum 86" stroke length and the BPUs have either a 120" and 144" maximum stroke.

This paper aims to review the current RRP surface drives along with those available on the market and create a framework for decision making which was applied to the RRP ramp-up.

ECONOMIC FRAMEWORK

To support the ramp-up of RRPs an economic study was conducted, this reviewed the relevant inputs and well conditions to generate a decision tree. The Surface Drive Equipment (SDE) that was included in the analysis included LRPs with a range of strokes from 56"-86"; Tower Units (TU) including the Weatherford Rotaflex 700 (236"), Weatherford Rotaflex 950 (288") and ChampionX Vertical Rod Pump (VRP) 500 (196"); beam units including 320-256-144 and 160-173-100. To understand the operating limitations of each SDE XROD models were generated to run though insert pump sizes from 1.25" -2.5" at Maximum SPM and optimal SPM (3.5SPM) at depths ranging from 600-1500m. Considering structural and other SDE limitations operating envelopes were developed for each SDE for both a 7" and 5.5" casing scenario as per Figure 2.

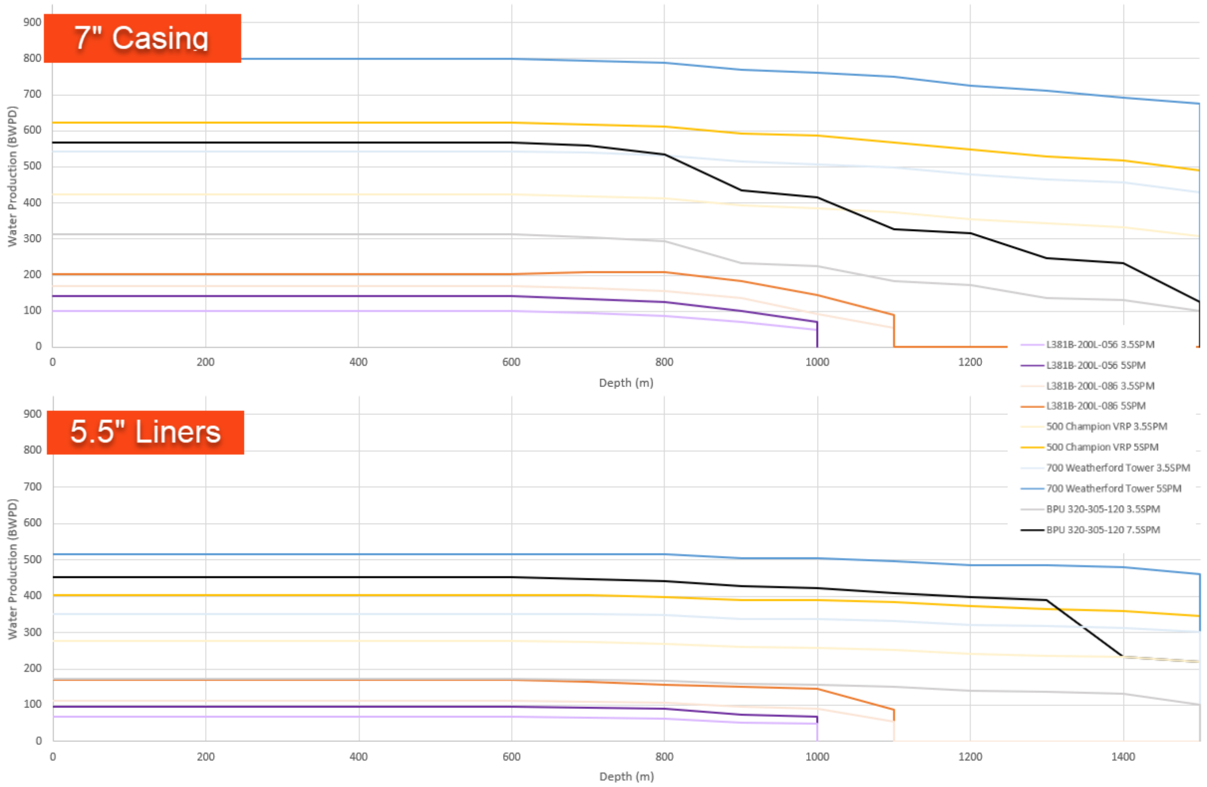

Figure 2: Maximum operating envelopes for main surface drives reviewed at maximum SPM vs. 3.5SPM

Other inputs included initial cost for installation (built up based on current knowledge), MTTF for the surface and subsurface failures, workover cost including required site preparation, Opex (both fixed and power usage) and mean time to return (MTTR). Power usage data was calculated from XROD models using various target water bands and a power/barrel of water calculated. Fixed Oped costs consist of the servicing requirements and spare parts to operate the SDE. MTTF for both subsurface and surface failures was generated in conjunction with the Global subject matter experts from ConocoPhillips Company. At this stage in the process the uplift potential was not incorporated into the economic assessment.

Surface failures for each unit were considered in terms of the items that had been replaced at significant services or had the most significant impact on the unit when a breakdown occurred. As required, strokes per year was used as an adjustment based on the required speeds to generate different water rates from the same SDE and downhole configuration. Significant failures for the LRP this was the gearbox; for TUs this was the load belt, sprocket bearing and top drum bearing; and BPU was the saddle bearing, tail bearing and wrist pins. Where stroke-based assessments increased the MTTF past 20 years the MTTF was capped. The MTTFs were generated for these parts based on the basic run life information from our partners, vendors and/or operational experiences. In Origin we have 2 types of workovers which can restore production post a subsurface failure, these include major workovers where tubing is pulled and the wellbore cleaned out of solids or minor workovers where only rods and insert pumps are changed. For major failures a MTTR of 1 month was applied with production impacts while minor unit failures assumed that there was no production impact, and the failure could be resolved in 7 days. To give a range for the model to work on a low of 90% and high of 110% of the average was applied.

Subsurface failures were calculated as an average from our current LRP fleet in the Bowen Basin, excluding pre-emptive workovers for integrity or diagnostic purposes. The strokes from installation to failure were then calculated and assigned to a water rate band. The MTTFs were extrapolated across the different SDE based on the modelled speed and online time required to achieve a specific water rate band. Water rate bands were selected based on water rate ranges from the SDE and these were <50bwpd, 51-150bwpd, 151-400bwpd and 401-600bwpd. To reflect the variability of potential subsurface failure a low range was set at 50% and high at 125% of the average. MTTF was capped at

120 months (10 years) in all cases. Surat basin MTTF was calculated for fracture stimulated wells as the same as the Bowen basin but where these were applied to non-facture stimulated wells it was reduced to 50% of the Bowen MTTF to account for the higher potential presence of solids until further information was known regarding performance.

This data, and the given ranges, were applied in Latin HyperCube Simulation which applied 100 iterations per simulation for each water rate and SDE choice combination. These models were run accounting for the selection criteria that included the water rate bands, 2 categories of well depth, location and casing size. The model was run on ~452 wells which was equivalent to ~173,000 iterations. The model assumed that 40% of the subsurface and surface failures required a major workover/service and 60% a minor workover/service.

The outcomes of this model drove the development of the decision tree in Figure 3. Some of the key takeaways from the model included a heavy reliance on the forecasted water rates for the final SDE decision and subsurface failures were the primary driver of cash flow variability since this drives online and offline times. NPV decisions were generally marginal (~1-2%) based on tight cost ranges of workovers and wells with lower gas rates (<100MMSCFD) or >15 years old generally had shorter economic lives and were unable to realise MTTF gains. The NPV outlook for both older wells and low rate gas wells provided an interesting challenge were by there is still increased potential uplift based on pressure drawdown, however, economic pay back periods are shorter thus higher rate wells in this age group would be targeted first.

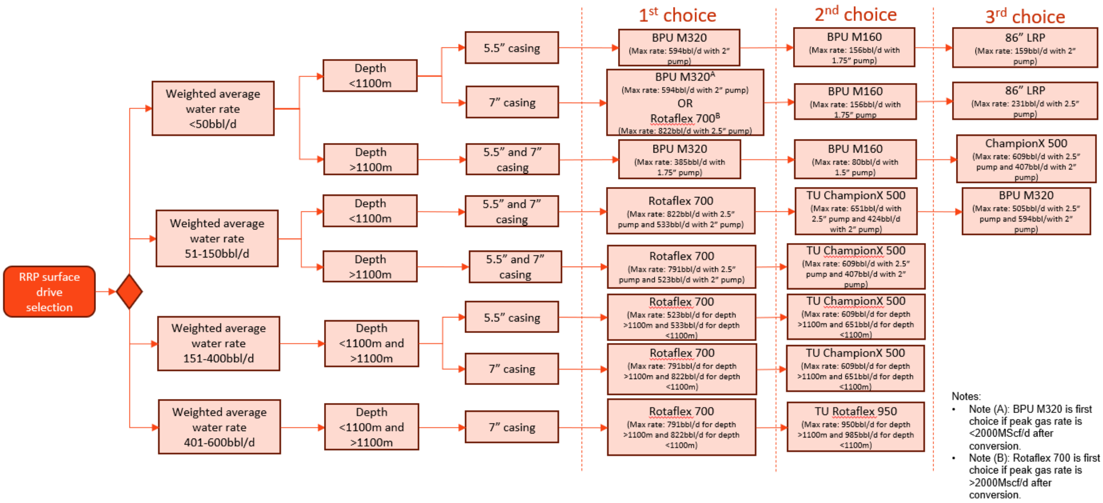

Figure 3: Finalised decision tree from selected inputs

This decision tree was to be used as a basis for reviewing the surface drive equipment (SDE) that should be installed per wellsite.

TECHNOLOGY TRIALS

Another element in decision making is how to rapidly improve the subsurface completions to suit the environment. One methodology that has been selected, among others, is a learn-fast mechanism. While this methodology is regularly used in a technology space its application allows solutions to our challenges to be trialled and if effective applied rapidly to a growing fleet of RRPs. For this method to work, diagnostics into the well performance must be monitored alongside dyno cards so that historical trending can be applied to identify issues and root causes can be established.

RRP availability and customization will also play a pivotal role in our ability to learn-fast. Long lead items can take up to 6 months to reach Australian shores. With limited RRP manufacture in country there is a real drive to move Australian pump shops towards a Texan model where more pump inventory is held in stores and pumps can be built and sent out rapidly to reduce downtime on wells. In Australia workovers are the one of the larger contributors to the NPV, as mentioned in the economics, thus reducing downtime and increasing production is pivotal to the shift in ALS. Similarly, refurbishment of

RRP parts will aid in reducing offline times as less components will be required to re-run a desired pump.

One example of the learn-fast methodology is observed in the current cage clearance trails. Multiple different cages are currently being installed across the fleet of rod pumps to increase the longevity of the ball and seat. This is one of our high failure points and is suspected to be caused by the increased rattle in the cage at higher gas rates. To learn-fast we baseline the current performance of the previous pumps and determine the approximate life before leaks are observed. These dates along with the well information can be applied to trails of other cages to determine susceptibility to failure and, therefore, potential advantageous designs. Along with this a gentle pump-off mechanism are to be implemented to aid in the further reduction of damage mechanisms for high gas producers [4]. Similarly, multiple different solids handling pumps will be installed over the next year to determine which pumps will better suit our environment and allow for increased MTTF. Increasing the ability for the RRP to handle solids also increases the potential candidate pools in which RRP conversions are possible.

SUCCESS AND CHALLENGES

To date many successes and challenges have been faced regarding our ambitious ramp-up targets. In working with the vendors, the first 2 tower units (TU) were installed in Australia, these were installed in January and May 2024. Many challenges were faced on the road to installation including but not limited to, changes to the surface drives to meet both the electrical and structural regulatory standards, hazardous area requirements and pilling rig availabilities. After the installation of these units the design for the piles was to be altered. For both previous installations the piles were drilled while the wellsite was offline due to multiple clashes with the wellhead/surface separator equipment and due to proximity to the wellheads. A new pile design was required for future installations which moved the piles back 1800mm from the wellhead centre and counter-levered the front weight bearing section of the subframes. The next 4 units installed within the field applied this new design which allowed wells to stay on production until close to commissioning of the TU. Structural, electrical and hazardous area requirements were resolved through the procurement of alternate parts, changes to the wiring and/or terminations, adjustment of structural components to meet standards and wellsite layout adjustments to ensure hazardous area requirements are met.

Another challenge that is faced in this ramp-up is material supply and equipment availability. Material supply challenges were faced subsurface and surface equipment required for SDE installation. With a fast-learning approach material changes were made to downhole equipment, but lead-times and shipping meant that these were not able to be implemented rapidly causing delays in potential benefits and long term MTTF in the RRP fleet. Similarly, some surface equipment and services had delayed installation. Pile rigs are a limited resource and are the first step to our current surface installation, thus, with the changes to the pile design, this section of the installation can be campaigned. Working alongside the vendors parts for the units have been sourced both locally and internationally to reduce lead-times and ensure product quality.

In preparation for increased BPU availability in coming years vendors have been engaged in design improvements to increase the usability of the units. Some such improvements include a mechanical mechanism for the horse's head to swing out of the engaged position, instead of being removed from the beam). A subframe like TUs for piled installations and introduction of the low maintenance bearing systems. An internal review on procedures for polished rod (PR) stick up has also been undertaken, this has allowed a review of current requirements and ensure that the walking beam is horizontal during a workover. In lieu of a horse's head mechanism this allows the current pin system to be used to manually rotate it out of the working zone for the rig. Vendors have also been engaged to create auto lubrication systems for the stuffing boxes on the TU and BPU as well as the top drum and sprocket for the TU's. These reduce maintenance and operational costs required to run the units long term with a large operational fleet. Innovations have also led to a smaller TU which under our depth and load requirements is more suited to the operational conditions. These updates will be considered in a revised version of the economic decision tree.

While these challenges have been faced in a medium-term project, the longer-term effects are yet to be observed. Over the next financial years, the number of installations is expected to at least triple, increasing the demand on the supply chain and ongoing contractors. This also puts increased pressure on the timeliness of installations and the rapid upskilling required for internal and external resources. Presently installations can take a month to complete with a maximum of 3-4 installations per month with some challenges being faced during commissioning. To further improve and reach the ambitious targets the rapid upskilling of internal and external stakeholders will be a key to continuous improvement, innovation and development.

CONCLUSION

The elements which have been crucial to the success of this project include the economic assessment and decision tree which aided in candidate and surface equipment selection. This reduced the available surface equipment options to a smaller pool and created a framework for candidate selection. Technology trails and fast learning has been and will continue to be integral to long-term MTTF benefits along with collaboration and innovation with vendors as required to achieve current and future installation targets.

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