ANALYSIS OF SOUTH AUSTRALIAN ONSHORE OIL & GAS WELL DECOMMISSIONING AND POTENTIAL IMPACT ON REGULATORY COMPLIANCE, ENVIRONMENTAL AND CORPORATE RISK

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FORMAT OF THESIS

This thesis is presented in two sections:

- Section 1: Publication
- Section 2: Thesis

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By signing the Statement of Authorship, each author certifies that:

i. the candidate's stated contribution to the publication is accurate (as detailed above);
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iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

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Analysis of South Australian Onshore Oil & Gas Well Decommissioning and Potential Impact on Regulatory Compliance, Environmental and Corporate Risk — Unified Risk Code

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The Cooper/Eromanga Basin is in central Australia and has been the focal point for oil and gas exploration and development in South Australia since the first commercial hydrocarbon discovery in 1963. In the years and decades following, thousands of subsequent wells have been drilled. The CE Basin spans across four states and territories covering an area ~35,000km^2. The concentration of South Australian wells is situated in the Northeast of the state and sparsely concentrated in a 300km × 500km area (Figure 1) with the wells in this area being the focus of this research study.

Well decommissioning commonly referred to as Plug and Abandonment (P&A) aims to restore the natural integrity of geological formations that existed prior to drilling. It is a mandatory requirement for all wells and must account for the effects of any foreseeable chemical and geological processes from an eternal standpoint. The minimum requirement for abandonment of the South Australian wells is governed by Objective 6 Cooper Basin State Environmental Objectives (SEO): Drilling, Completions and Well Operations, November 2015 guidelines, which provides the compliance criteria for appropriate barrier installation and verification.

Well complexity is determined by the difficulty in achieving this minimum compliance requirement based on available data of well conditions, simplified in the form of a risk code.

Introduction

The Cooper/Eromanga Basin is in central Australia and has been the focal point for oil and gas exploration and development in South Australia since the first commercial hydrocarbon discovery in 1963. In the years and decades following, thousands of subsequent wells have been drilled. The CE Basin spans across four states and territories covering an area ~35,000km^2. The concentration of South Australian wells is situated in the Northeast of the state and sparsely concentrated in a 300km × 500km area (Figure 1) with the wells in this area being the focus of this research study.

Figure 1—Location of the Cooper Basin and South Australian Cooper Basin Wells.

Well decommissioning commonly referred to as Plug and Abandonment (P&A) aims to restore the natural integrity of geological formations that existed prior to drilling. It is a mandatory requirement for all wells and must account for the effects of any foreseeable chemical and geological processes from an eternal standpoint. The minimum requirement for abandonment of the South Australian wells is governed by Objective 6 Cooper Basin State Environmental Objectives (SEO): Drilling, Completions and Well Operations, November 2015 guidelines, which provides the compliance criteria for appropriate barrier installation and verification.

Well complexity is determined by the difficulty in achieving this minimum compliance requirement based on available data of well conditions, simplified in the form of a risk code.

This paper presents a "**Unified Risk Code**" which has been developed as a scalable metric utilizing well data at a macro level for classification. It can be modified with any data pertinent to well complexity. It can be used to rank wells or be used to apply cost multipliers to more accurately approximate P&A liability. This can be done at any level; basin, field, well; by company or by any other well characteristic. In the example code within this paper, six metrics applied to all wells in the South Australian - Cooper Eromanga (SA-CE) Basin are discussed. These include well geometry, well age, shut in time, depth, behind pipe zonal exposure and relevance of application.

The intention of the risk code is not to develop prescriptive intervention strategies. The unified code is a means for well complexity classification and does not replace detailed engineering work required as part of individual well assessment. It is an improvement in screening and macro application of high complexity large volumes data sets. The drivers behind this research along with decommissioning performance in South Australian wells are covered in the following sections.

Performance Criteria

Data collected in South Australia from 1968 to 2017*illustrate the rate of new drills exceeding the rate of abandonment. Figure 2 tracks 2,457 wells over the period, broadly categorizing them into the following categories:

1. Producing or suspended (not P&A): 1,695 wells (green)
2. P&A immediately after drilling (no hydrocarbons present): 643 wells (blue)
3. P&A in later life (post-suspension/post-production): 119 wells (red)

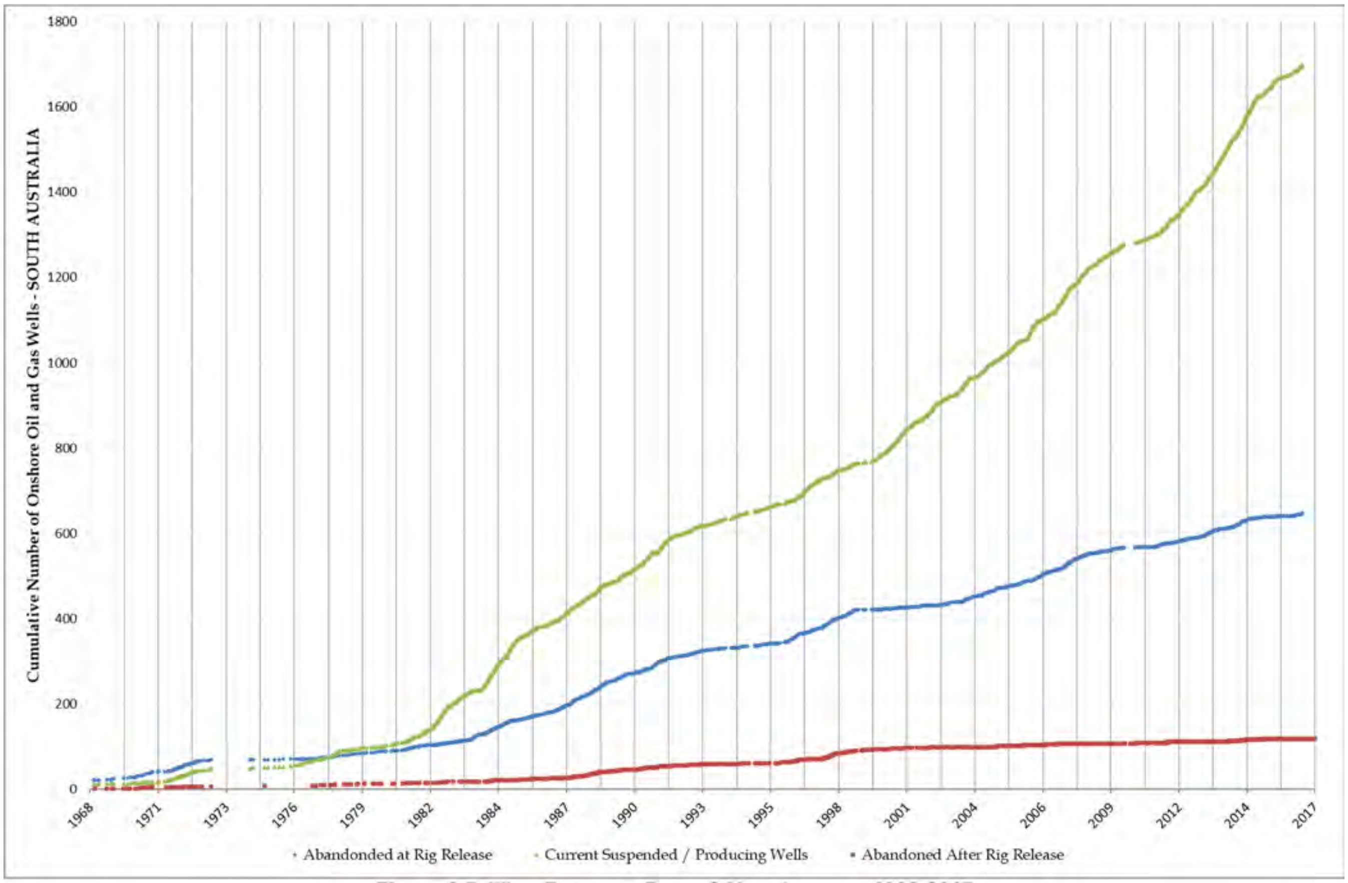


Figure 2—Drilling Rates vs. Rate of Abandonment 1968-2017

* Data is captured in the period from 1968-2017. The research commenced in 2019 with a two-year privacy period existing on well files prior to PEPS public release of well data.

Wells plugged and abandoned immediately after drilling (blue line) are not considered in the performance criteria as these wells do not require any future intervention. Of notable interest is the increasing trend associated with producing and suspended wells (green line) and the relatively flat trend of wells late life P&As (red line). This divergence illustrates that very few wells are being visited for decommissioning as part of end of well life. The inventory of expired wells is also increasing.

This divergence is supported as the data discriminates between producing wells and shut-in/suspended wells. In the SA-CE basin at the time of this analysis, there were:

- 1,695 producing or suspended wells
  - 898 reported producing wells (52% of wells located on the y-axis)
  - 797 Shut in (48% wells away from the y-axis)
    - Shut in 0-5 years (zone 1) – 307 wells (18.1%)
    - Shut in 5-10 years (zone 2) – 180 wells (10.6%)
    - Shut in 10+ years (zone 3) – 310 wells (18.3%)

This is presented graphically in Figure 3 plotted against well age.

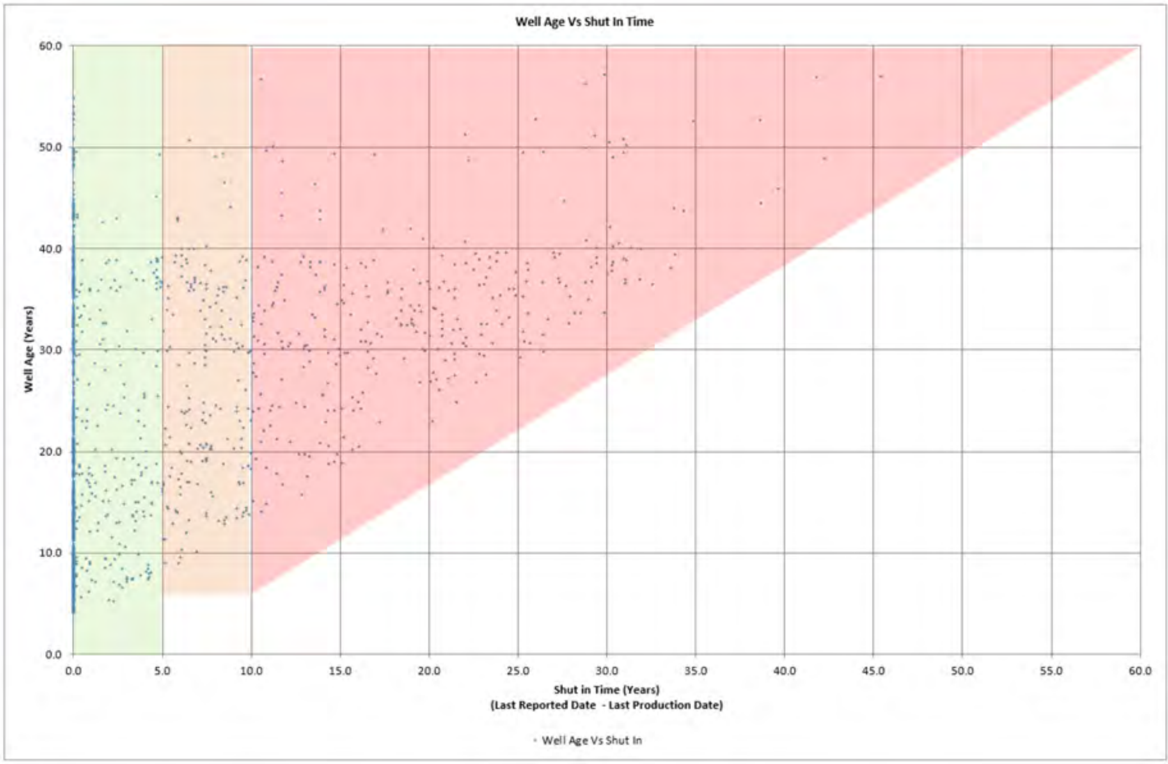


Figure 3—Well Age vs. Shut in Time of SA Cooper Basin Wells

There is a significant inventory of wells in the orange/red sections (long term shut in) with well age greater than 20 years and with a basin age average of 23 years. It is evident the large volume of wells that are potential P&A candidates are not being addressed.

A comparison to analogue basins has not been considered as part of the current research but is planned for future work. This work will compare basin trends within Australia and overseas to identify key influencing factors to promote proactive P&A.

Problem Statement

Intervention works to P&A wells are often complicated and costly, and the work scope is executed under uncertain conditions. Wells, particularly mature assets are often shut in for extended periods leading to integrity risk exposure. The large volume of wells is difficult to evaluate individually and a means to assess risks using computer models is therefore required.

Key issues:

- Significant potential commercial exposure associated with many onshore oil and gas wells
- Designed life often exceeded including expired wells that have been shut in long term (>10 years without production)
- Environmental exposure risk due to wells that have been shut in but not abandoned, in some cases for decades
- Limited public record of intervention activities (if any) and of shut-in wells, presenting a significant degree of uncertainty around the integrity of said wells and other related conditions in the wellbore.

As a result of the review, several industry wide gaps in knowledge were identified in current operations and regulatory construct. The objectives and extended objectives of the project were formulated to address these gaps in knowledge.

Gaps in Knowledge

1. No evaluation of the SA onshore well database to identify potential commercial, environmental, legal, and regulatory exposures has been reported
2. Forward-looking abandonment strategies are not mature enough to encourage operators to mitigate associated risks and prioritize abandonments of shut-in wells
3. No industry wide repository of learnings with regards to well integrity and well construction data from thousands of wells that have already been drilled.
4. No industry wide understanding of potential exposures and analogous behavior patterns from specific formations in the SA-CE basin
5. Limited local research conducted to understand the most effective and economic solution in managing expired inventory
6. No unified method to evaluate well risk at a macro scale (basin wide), being reliant on operator management of assessment of risk with an increasing well integrity management workload

This paper presents the following objectives developed to address the gaps in knowledge aforementioned.

Research Objective

This paper provides insight into the research currently being undertaken at the Australian School of Petroleum and Energy Resources (ASPER), University of Adelaide. The research objectives are:

1. Develop a unified risk code to quantify complexity of these wells and factor them into cost of executing an abandonment program
2. Analyze South Australian Onshore Oil and Gas well database to identify wells that present the greatest potential commercial, environmental, legal, and regulatory exposure for operators
3. Use well construction and cementing data, identify zonal isolation opportunities
4. Research relevant regulatory compliance and confirm compliance/non-compliance to zonal isolation requirements
5. Research, analyze and discuss potential deterrents to abandonment from an operator and regulatory perspective

In this paper a summary of the methodology for research objective 1 from the research is presented.

Methodology

Using publicly available data on well construction (Appendix 1), information was analyzed to develop insight into the wells of the SA-CE Basin along with several metrics (Appendix 2). The methodology presented below covers the research objective 1 - unified risk code and does not extend to the other research objectives.

The intellectual property in the algorithms developed are not included in this paper. The methodology is a representation of how well construction data can be used in a similar manner to develop a risk code suitable to one's own application.

In the example presented, six features have been used to define well risk. The limit to the following can be expanded or reduced as required based on operator experience of what impacts risks/costs for their own assets. Using these methods, algorithms using in-house knowledge and expertise to refine prediction of outcome can be achieved.

Each of the features (1-6 discussed) these are sub categorized, with a respective multiplier 1.0/1.1/1.2 applied as shown in Table 1.

While the proprietary model features and multipliers are intellectual property, the values below are proposed "reasonable" features and multipliers for the purpose of illustration.

Table 1—Feature and Risk-Based Multiplier as part of Unified Risk Code

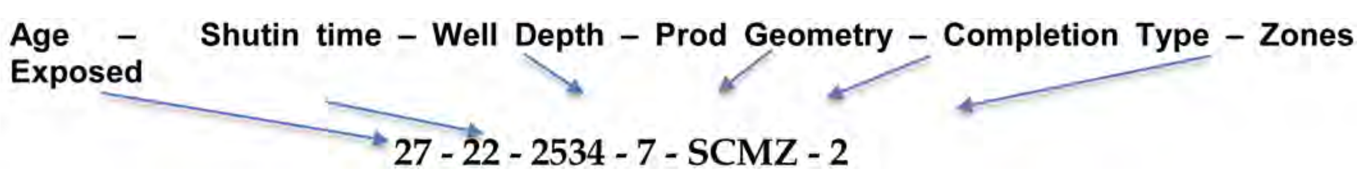
	Feature					
	Well Age	**Shut-in time**	**Well Depth**	**Production Casing**	**Completion Status**	**Zones Exposed**
Base Case	0 to 10 years	1 to 10 years	0 to 2500m	5.5" +	SC	0
Multiplier	**1x**	**1x**	**1x**	**1x**	**1x**	**1x**
Medium Case	11 to 20 years	11 to 20 years	2501 to 3500m	4.5" to 5.5"	SCMZ, S, P&S	1 to 3
Multiplier	**1.1x**	**1.1x**	**1.1x**	**1.1x**	**1.1x**	**1.1x**
High Case	20 years +	20 years +	3500m +	0 to 4.5"	DC, MC	4 to 6
Multiplier	**1.2x**	**1.2x**	**1.2x**	**1.2x**	**1.2x**	**1.2x**

If a well is ranked as base case (low risk) in all 6 features, it will have a total multiplier of 1.0^6=1.0 unified risk rating (Lowest). Conversely, if a well is ranked high case (high risk) in all 6 features, it will have 1.2^6 = 2.99 unified risk rating (Highest).

The features and categorization of risk is covered in the subsequent section but the key points to note are:

- The features selected are completely customizable
- The number of features is to the discretion of the user limited only by available data
- Additional features can be included from proprietary data (e.g. well integrity reports, production reports, compositional analysis)
- The multipliers can be adjusted as required based on experience
- Examples of how the risk code and risk rating can be used is provided as a separate section in this paper
- An example breakdown of a unified risk code is provided below

Operator name and well name: **Undisclosed**
Unified Risk Code Key:



Unified Risk Code:

- First feature represents: Well age – 27 years
- Second feature represents: Shut in time – 22 years.
- Third feature represents: Well depth – 2534 m
- Fourth feature represents: Production casing Outer Diameter (OD) – 7 inches
- Fifth feature represents: Completion status –Single completion multiple zones (SCMZ)
- Sixth feature represents: Zones exposed – 2

The associated risk rating for the well with a unified risk code can then be developed based on criteria and shown below

Table 2—Example Risk Multipliers for Unified Risk Code 27-22-2534-7-SCMZ-2

Well Age Cost Multiple	Shut-in Time Cost Multiple	Well Depth Cost Multiple	Production Casing Cost Multiple	Completion Type Cost Multiple	Zones Opened Cost Multiple
1.2	1.2	1.1	1	1.1	1.1

27-22-2534-7-SCMZ-2 Well Risk Rating 1.91/2.99

This is a fully scalable and flexible methodology for screening large volumes of data that can compare wells using the unified risk code or the risk rating determined. The following sections illustrate how the six metrics provided in this example have been used or considered, alongside further background information.

Well and Production Geometry

How wells are drilled is dependent on the nature of the targets (gas vs. oil), technology, well objectives and who is undertaking the work and what period the well was drilled.

Figure 4 Well Drilling Geometry and Normalized Drilling Rates over Time in**SA Cooper Basin**-CE basin (Figure 4) investigates the evolution of well geometry from the 1960s to 2017. The primary y-axis on the left measures outer diameter in inches and the secondary y-axis on the right measures normalized drilling rates in meters/day. The x-axis measures the time component of this evolution. The blue data points showcase the outer diameter of the drilled hole (i.e. drill bit), with the red data points representing production casing outer diameters.

- Pre-1995, almost all wells drilled exclusively with 8.5" hole and completed with 7" production casing
- Post-1995, 6-3/4" drilling became more common, with smaller production casing becoming common (2'7/8", 3.5", 4.5",5.5")

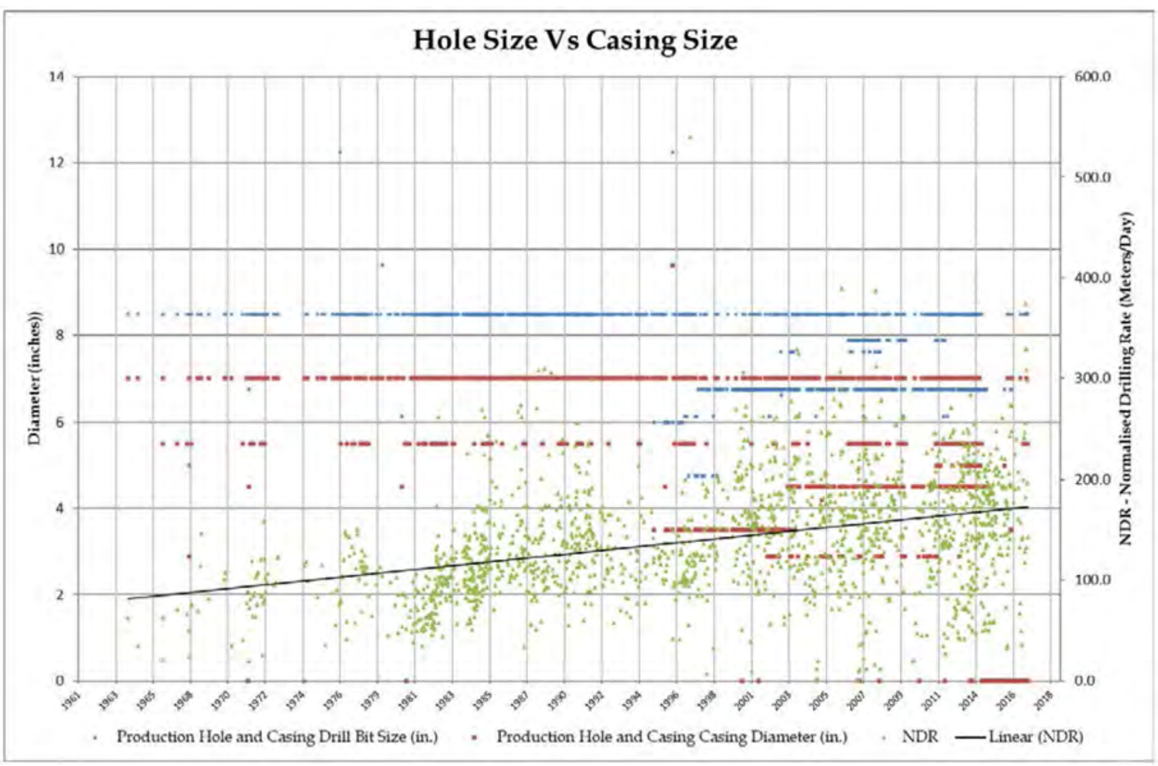


Figure 4—Well Drilling Geometry and Normalized Drilling Rates over Time in SA Cooper Basin

The green data points showcase how normalized drilling rates have changed with time. The scatter trend illustrates an incremental increase in Normalized Drilling Rate (NDR) (normalized against depth) over time implying an improvement in drilling performance alongside reduced hole and casing size practices.

In the unified risk code presented within this example, the following risk multipliers have been applied:

– 5.5" or greater production casing OD **1.0 multiplier**
– 4.5" to 5.5" production casing OD **1.1 multiplier**
– < 4.5" in production casing OD **1.2 multiplier**

This is based on the requirement for downhole tool passage, capability to fish, and scale deposition prior to it becoming a restriction. While operator and industry engineering body of knowledge may assess this differently, the intention is to demonstrate how this metric is used as a discriminator.

From the available data, it is possible to have further layers on well geometry with consideration to dog leg severity, trajectory, internal upsets on connections, casing weights and grades. For this example, only production casing OD is considered.

Well Age

The age of the well can be a contributory risk factor. The likelihood for wellbore integrity issues to occur increases as downhole equipment reaches or exceeds design life. In Figure 5 below, 842 wells representing approximately 49% of total active wells are over the age of 20 years.

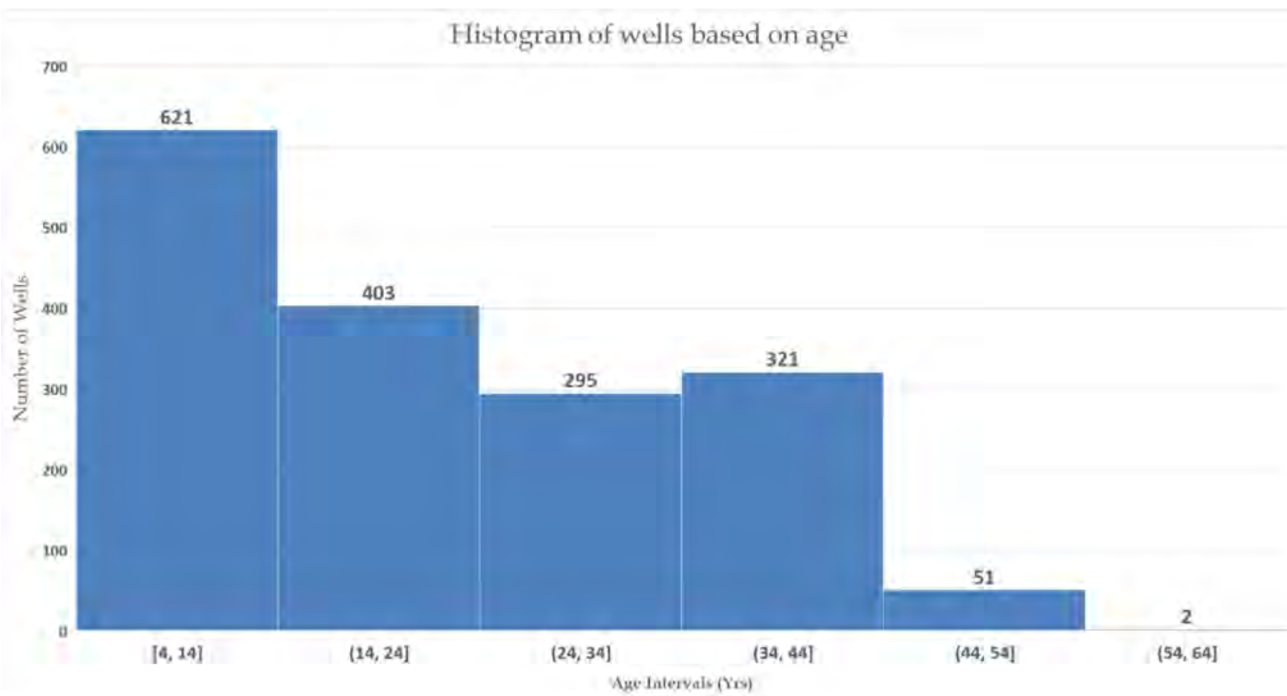


Figure 5—Well Age Histogram

Well age alone is being used as an example of what could be considered in the unified risk code. Application of the code may also consider other factors including metallurgy and gas composition, temperature and corrosion models, and tie in production for time dependent risk codes.

In this unified risk code example, the following multipliers are applied for Well Age:

– Less 10 years: **1.0 multiplier**
– 10 – 20 years: **1.1 multiplier**
– 20 years plug: **1.2 multiplier**

Shut in time

Wells are shut in for safety reasons due to unidentifiable behavior in the wellbore; but the most common reason for a shut-in is due to a well becoming uneconomic to produce from (the cost of extraction is greater than the price the produced hydrocarbons would fetch at market). Once a well is shut in, it can be brought back online at any time once conditions for production are favorable. However, once a well has been left shut in for an extended period, there is no way for the operator to know true downhole conditions without verification.

The assumption remains that the longer wells have been shut in for, the greater the commercial and environmental risk they carry. The commercial risk pertains to legal liabilities that arise from uncontrolled release of hydrocarbons.

As seen in the Figure 6, there are a total of 640 "active", non-abandoned wells that have been shut in. This represents 38% of the total active wells. Furthermore, 391 of the shut-in wells have been shut in for over 6 years, representing a significant 61% that falls in this category. 256 of the total number of shut-in wells have been in shut in for over 10 years.

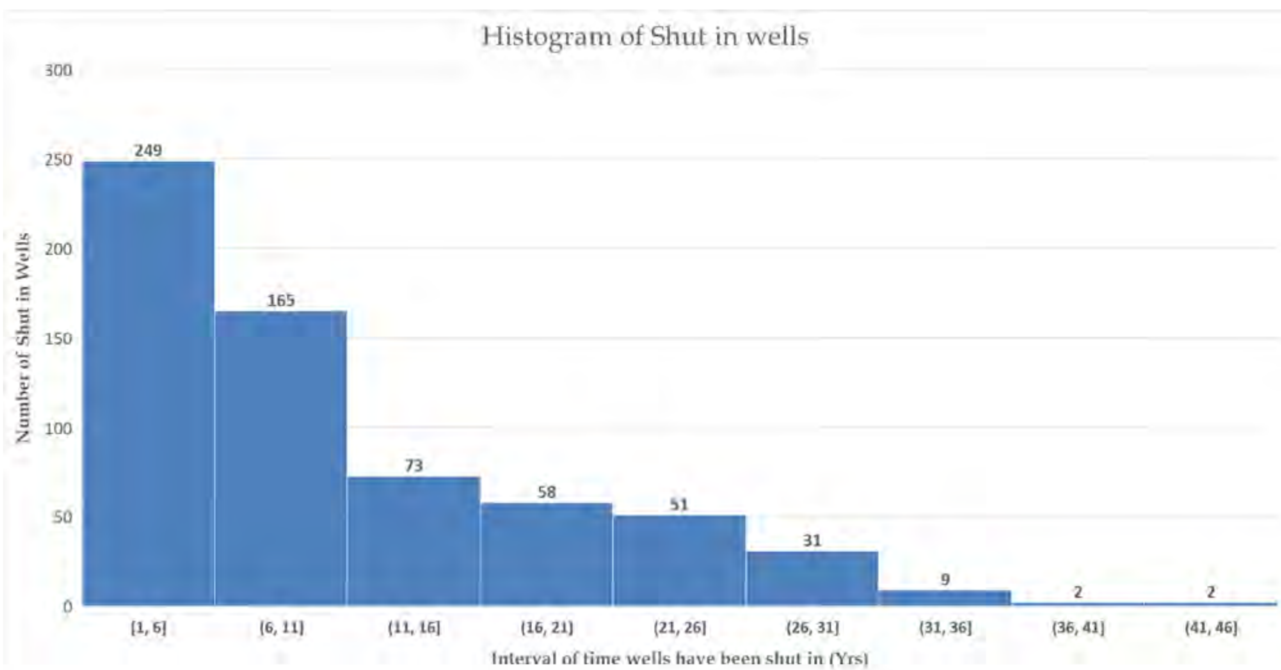


Figure 6—Shut in Time Histogram

If the design life of the completion and associated wellbore equipment is 10-20 years, and the last time an intervention was executed was right before shutting the well in, then 40% of total shut in wells are operating beyond their design life. With further progression of time, more wells will be falling into this category if no action is taken. This lack of action on suspended wells adds to the risk profile of the wells over time.

Given the high volume of wells, risk codes can be used to develop a priority list of wells to be addressed first and gain an understanding of the implications of a no action taken scenario. Furthermore, by using fixed assumptions on risk criteria, this method can project what a risk profile will look like into the future with no action or with a planned strategy.

Figure 7 (where the vertical axis represents well age and horizontal axis representing shut-in time) implies that data points that are on the y-axis are currently producing wells. This plot includes all wells that are not abandoned and have reported production data.

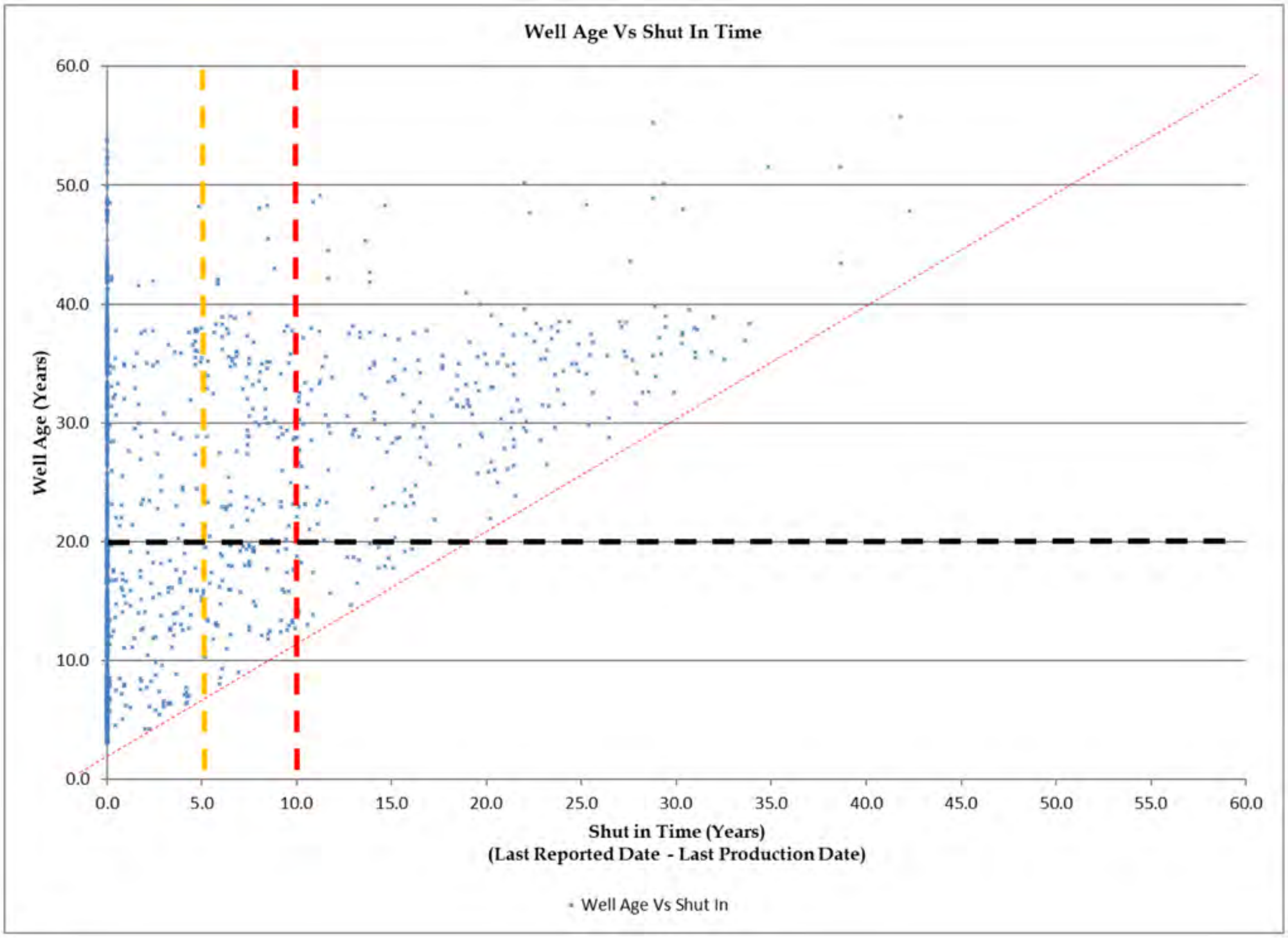


Figure 7—Well Age vs. Shut in Time

Due to the design life of downhole equipment ranging from 10-20 years, wells with well age less than 20 years are deemed to be at minimal risk for integrity failure. This is represented by data points below the black dotted horizontal line. 46.8% of wells are in this category.

- 0-10 years shut in **1.0 multiplier.**
- 10-20 years shut in. **1.1 multiplier**
- 20+ years shut in: **1.2 multiplier**

Examples could include the treatment of oil and gas wells differently or inclusion of well pressures (dead wells treated differently than wells with pressure).

Well Depth

Well depth is included as part of well complexity in abandonment due as it has greater impact on wellbore conditions. Deeper wells generally have higher abandonment costs.

From a geological perspective, a deeper well crosses more formations that have varying behavior, pressure, and temperature systems, thus adding to complexity in terms of well design (Figure 8).

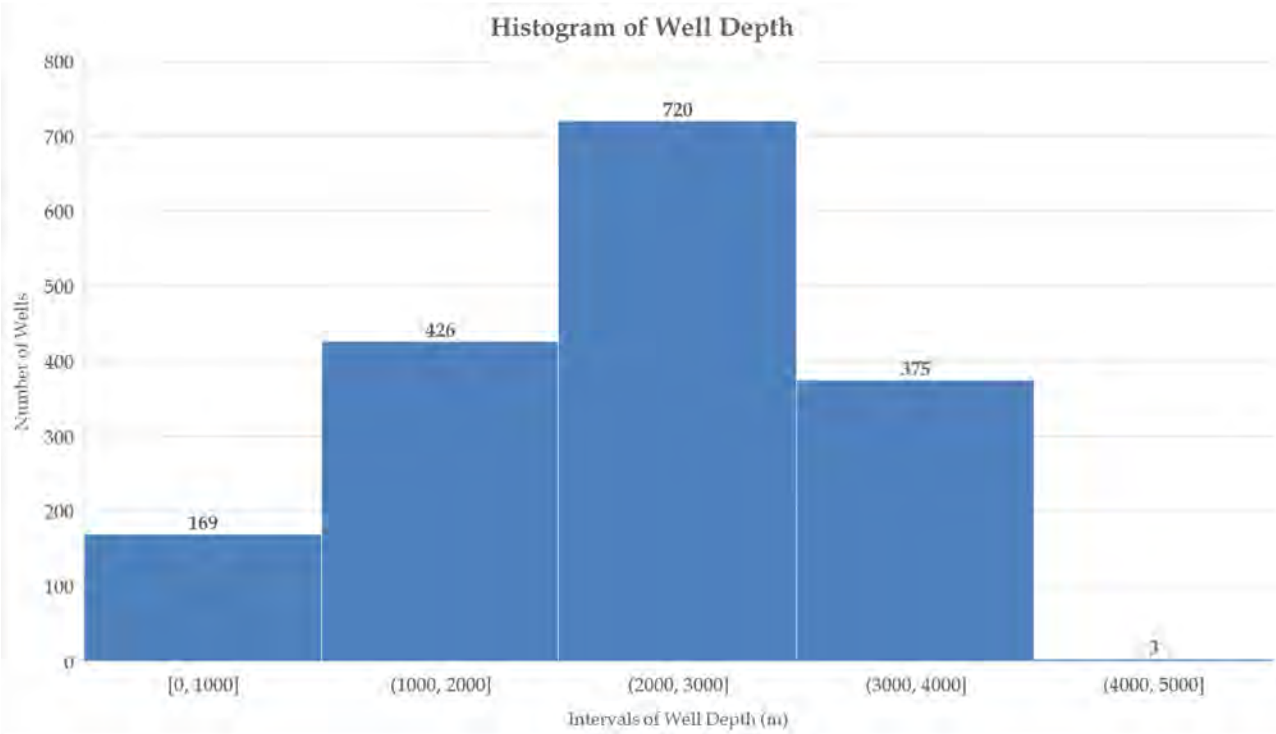


Figure 8—Well Depth Histogram

Like previous features, there can be a risk distribution attributable to well depth which can be broken down as required

- All wells less than 2,500m in depth are low risk – 64% of total wells: **1.0 multiplier**
- All wells between 2,500m and 3,500m are medium risk – 31% of total wells: **1.1 multiplier**
- All wells greater than 3,500m are high risk – 1% of wells: **1.2 multiplier**

An example of how depth can be considered is through the understanding of rig limitation. Wells exceeding a certain depth using a particular tubing/casing size may dictate a larger, more expensive rig. As such, beyond a certain depth/casing size, said wells can have a multiplier of 2X or 3X to capture complexity and hardware requirements.

Completion Status

There are seven broad completion categories included as part of the risk code:

- Single completion
- Single completion multiple zone
- Monobore completion
- Dual completion
- Suspended
- Plugged and suspended.
- Coiled tubing deepened

Executing abandonment activities have varying degrees of complexity as they are heavily dependent on the completion status of the well prior to the abandonment. Moreover, different completions have various degrees of susceptibility to well integrity issues over time.

Like other features, various levels of risk exist which are proportional to the complexity of the completion:

- Single completion – 30% of total wells: **multiplier 1.0**
- Single completion multiple zones, suspended or plugged & suspended – 31% of total wells: **multiplier 1.1**
- Monobore completions or dual completions – 11% of wells: **multiplier 1.2**

This is a simplistic assessment of completion complexity. A detailed algorithm could include a combination of depth, completion, installed hardware, ID restrictions as well as intervention requirements.

Zonal Exposure

The previous five features are directly sourced from well completion reports. The following is an example how a risk metric can be developed using a combination of data. Using formation top data, casing set depths, Cement Bond Log (CBL), cementing reports, top of cement and by cross checking against SEO requirements, the number of zones behind casing that require cement were determined. There were multiple permeable groups/zones as per SEO requirements requiring isolation to stop interzonal communication.

In Figure 9 the horizontal axis represents the names of the wells; with the vertical axis representing depth in meters. Grey lines denote production liner depth, overlaying black lines denoting intermediate casing depth and the green data points showcase top of cement. The wells that do not have TOC data still have associated data points at surface.

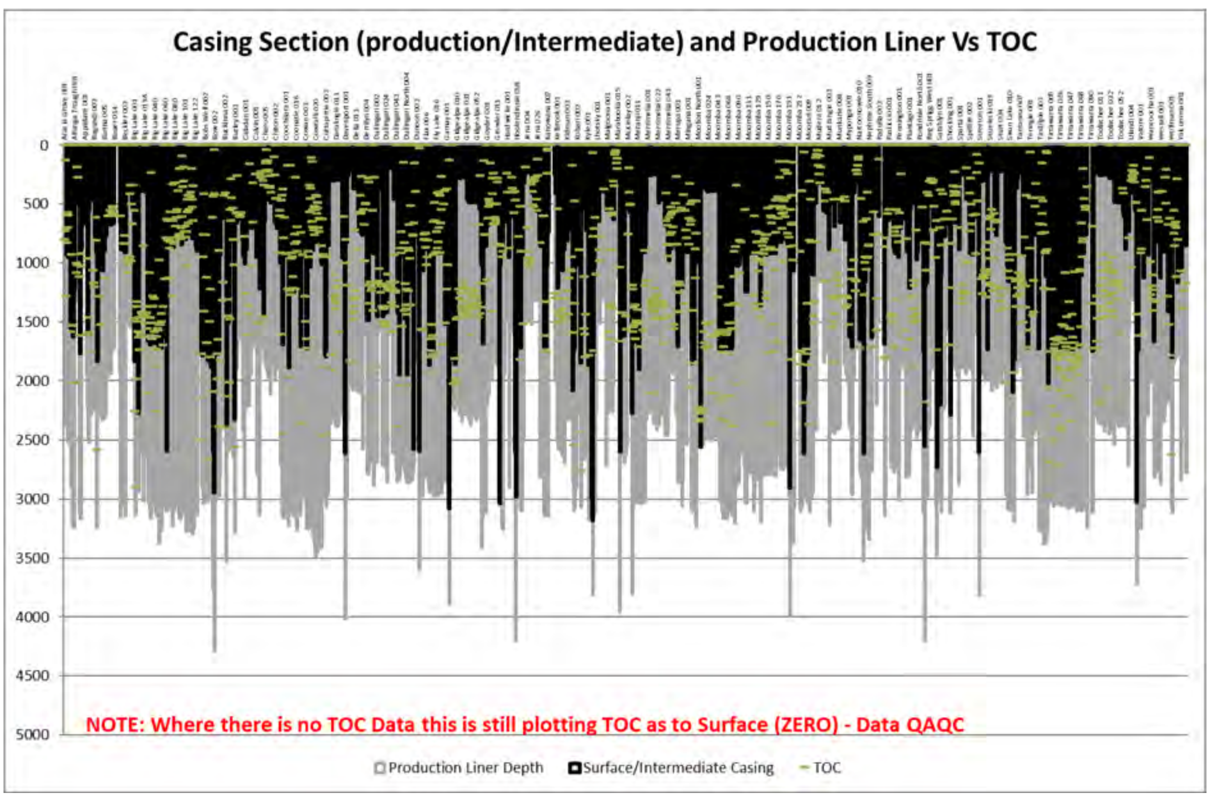


Figure 9—Casing Section vs. TOC

- Green mark overlapping black vertical: Top of Cement above previous shoe

- Green mark overlapping grey vertical: Top of Cement not inside previous shoe
    - o Zones exposed and number of zones using formation top depths can be calculated and zonal isolation via section milling or squeezing can be calculated.

Figure 10 below denotes number of wells on the vertical axis and bins of zonal exposure on the x-axis. Over the entire basin, there are 1,146 wells that have no zonal exposure which leaves 1,200 wells with zonal exposure. This implies that over 51% of total wells are exposed to integrity failure risk by virtue of zonal exposure that do not meet zonal isolation requirements. 707 wells have at least one zone exposed, 493 wells have more than 1 zone exposed, representing a 21% proportion of total number of wells. This analysis shows criticality of monitoring wells with multiple zones exposed. There are 89 wells with more than 4 zones exposed which at abandonment would be of higher complexity.

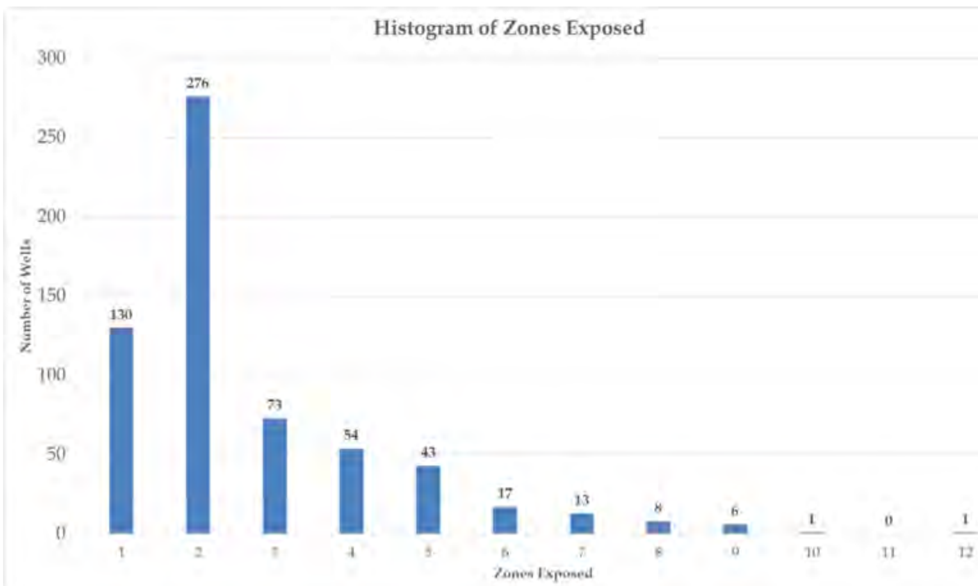


Figure 10—Zonal Exposure Histogram

There have been notable improvements in cementing practice over the SA-CE drilling history. As observed in Figure 11, earlier drilling practices through the 1970s, 1980s and 1990s were relatively inconsistent and showcased 462 instances (54% of wells drilled) where top of cement was deeper than production casing, leaving potential for zonal exposure. In the subsequent period 1990 to 2017, drilling practices showed a higher prevalence of cement returned to the previous shoe (Figure 12).

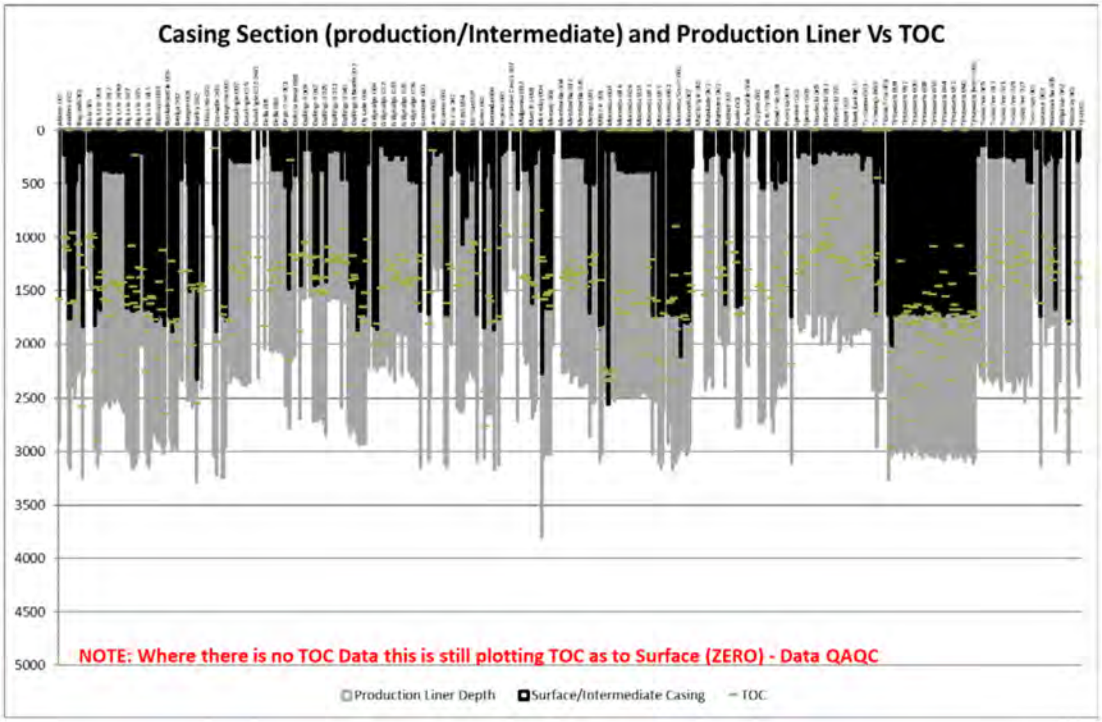


Figure 11—Casing Section vs. TOC Period 1975 to 1990

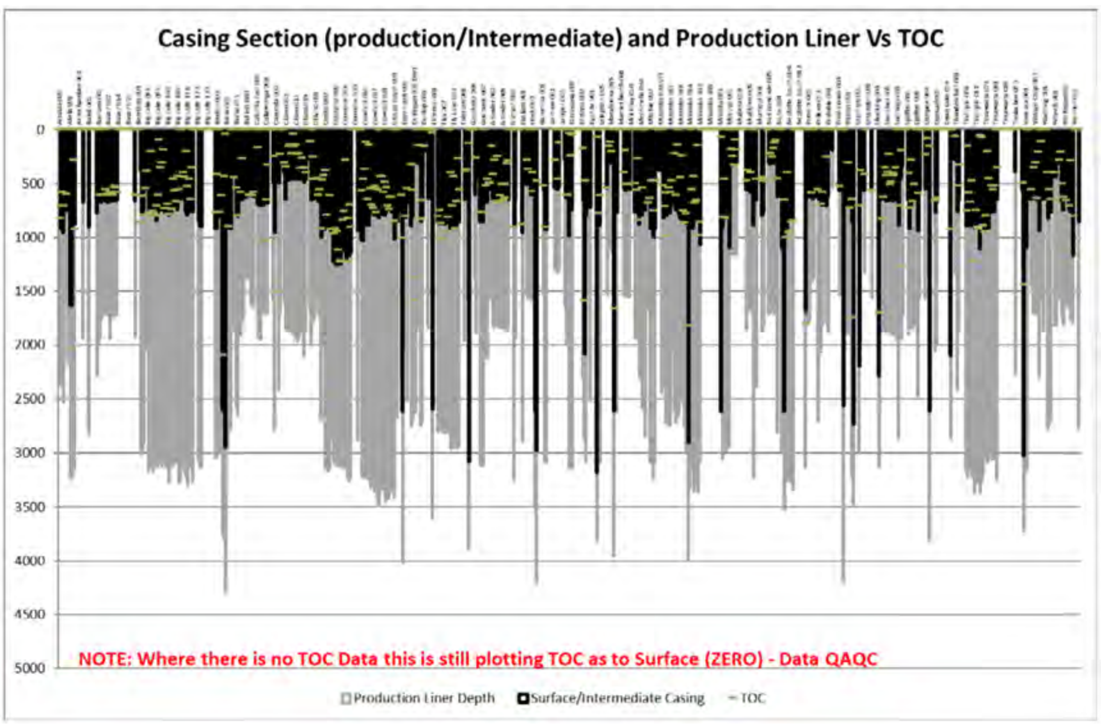


Figure 12—Casing Section vs. TOC Period 1990 to 2017

In stark contrast to the previous time frame, since 1990 there have been 208 instances (13% of total wells drilled) where top of cement was deeper than production casing, thus leaving smaller potential for zonal exposure compared to the period prior. This shows a clear improvement in drilling practices in the basin.

- No zones exposed: **1.0 multiplier**.

- 1-3 zones exposed: **1.1 multiplier**.
- 3+ zones exposed: **1.2 multiplier**.

Commercial Evaluation – Example Utilization of the Unified Risk Code

The following section demonstrates how the unified risk code can be used for commercial evaluations for an individual well.

Assumptions:

- Average daily service cost per well: **$22,000 AUD**
- Average time taken to abandon a well: **12 days**(this number varies based on complexity, however in this research there were complexity multipliers added to the relevant features; hence this time assumed constant across all wells)
- Base case cost per well: $22,000*12 days = **$264,000 AUD for risk multiplier 1.0**
- Mobilization and other logistical, administrative, and regulatory costs are ignored for the purposes of this research

Using the previous unified risk code presented in methodology 27 – 22 – 2534 – 7 – SCMZ – 2 which has an associated risk of 1.91664. Total cost for this well = Base case * Product of Multipliers = 1.91664*264,000 = $505,992 AUD

This can easily be extended to groups of wells selected by type, area or complexity and assumptions on daily rates can be made as required. Furthermore, assumptions can be calibrated to be able to effectively estimate the cost of future interventions of similar wells.

Importantly, engineering effort in planning and logistics can be recorded for each well type. This can be as part of interventions planning, logistics and be used to determine what additional resources are required to better estimate and rank well complexity.

At a macro scale, the universal risk code can be used to better estimate organizational liability for downhole decommissioning. This work is not presented in this paper as it is currently using proprietary data and IP for the risk code. The property unified risk code developed for the Cooper Eromanga basin has been shown to be an efficient cost estimation tool that is within 5% accuracy of manual calculations.

Conclusions

1. In the South Australian portion of the Cooper Eromanga basin, the portfolio of wells that are shut in or suspended has been growing over the past 60 years. This is due to the slower rate of abandonment versus Drilling rate. As a result, operators in the basin face increasing environmental, regulatory, and operational risk associated with mature/maturing assets.
2. The average age of wells in the basin is 23 years. Given a typical design life of downhole equipment of 20 years, an abandonment strategy is needed in the very near term.
3. A review of the wells in the SA-CE basin revealed there are 622 wells that are non-compliant, corresponding to 25.5% of wells being non-compliant to SEO objectives for zonal isolation. Zonal isolation is a critical risk as it pertains to well integrity. By investigating CE basin drilling practices through time; it is apparent that a larger proportion of older wells have top of cement deeper than production casing shoe compared to newer wells. This implies zonal exposure has reduced over time, owing to improving drilling practices and better risk management strategies in place.
4. There are multiple factors that have been considered as contributors to well integrity. In this research, the following six parameters were presented as an example. Other factors can be added, removed, or modified to ensure the universal risk code is a comprehensive and scalable assessment of risk.

a. Well Age (Yrs.)
b. Shut-in time (Yrs.)
c. Drilling and Production Geometry (Hole and Casing OD)
d. Well Depth (m)
e. Completion Status
f. Zonal exposure

The six critical parameters were used to define a unique alphanumeric risk code for each well that would help provide context on risk associated with a particular well and contributing parameters. The example provided uses publicly available data and is included in Appendix A. Examples of calculated features are included in Appendix B. Development of a unified risk code to better manage well complexity has been provided but there are opportunities to utilize in-house data and knowledge to customize a more meaningful code unique to the user.

5. To calculate cost of abandonment for all the wells in the basin, a base case was defined based on input. This base case cost accounted for 12 days taken to abandon a particular well and $22,000 AUD for services, resulting into a total of $264,000 per well (risk rating 1.0, assuming a 12-day operation). Under the assumptions presented, costs could increase by 2.98 times.
6. As a part of the forward-looking abandonment strategy proposed, the magnitude of the abandonment task and associated costs are in the hundreds of millions of dollars. To execute this strategy effectively and economically, some emerging technologies were potential options but could prove to be a creative, unconventional solution compared to traditional abandonment methods, application of which needs further evaluation.
7. A unified risk code which includes time dependent metrics can be used to project a risk position forward. Well age; shut-in time; corrosion rates and other examples are all time dependent variables. These can be used to show the risk position with no intervention, or to check if a planned abandonment strategy will meet corporate and regulatory objectives.

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Appendix 1

This research is based on a publicly available dataset containing all the raw data analyzed in a structured manner. This dataset contains information for 2,436 wells across a multitude of operators in the Cooper Eromanga basin in South Australia. It is critical to note that only O&G wells were considered in this analysis. All CSG wells, water wells and other types of wells were filtered out. The following is the type of information available in the database alongside associated interpretations/descriptions.

Feature ID	Feature	Description
1	Well	Name of the well
2	Operator	Company responsible for operating the well
3	Province	South Australian province where well is located
4	Spudded Date	Date when drilling starts
5	Rig Release Date	Date when drilling is completed
6	Class	Class of well - Exploration, appraisal, or development
7	Type	Type of well - Oil, gas or dry
8	Status RR	Status at rig release - Abandoned, suspended, plugged & suspended or single completion
9	Review Date	Date at which last review on the well was performed
10	Completion Status	Completion status of the well and type of completion
11	Completion Date	Date when completion was performed
12	Driller/Rig	Service provider responsible for drilling activities
13	Primary Objective	Priority target formations to be produced from
14	Secondary Objective	Second priority target formations to be produced from
15	License Type	Type of license - Exploration, production, or retention
16	License Number	License number
17	Current PPL	Current Petroleum Production License Number
18	Start Depth (Meters)	Depth at which drilling Starts
19	Total Depth (Meters)	Depth at which drilling Ends
20	Ground Level (Meters)	Datum depth
21	Kelly Bushing (Meters)	Depth from Kelly Bushing
22	Deviation	Deviation type - Vertical, low angle, high angle, horizontal
23	Height Datum	Reference scale for object height calculation
24	GDA Latitude	Geocentric latitude
25	GDA Longitude	Geocentric longitude
26	GDA Latitude Degrees	Geolocation feature
27	GDA Latitude Minutes	Geolocation feature
28	GDA Latitude Seconds	Geolocation feature
29	GDA Longitude Degrees	Geolocation feature
30	GDA Longitude Mins	Geolocation feature
31	GDA Longitude Seconds	Geolocation feature
32	GDA Easting	Geolocation feature
33	GDA Northing	Geolocation feature

Feature ID	Feature	Description
34	GDA Zone	Geolocation feature
35	Datum	Geolocation feature
36	X	Geolocation feature
37	Y	Geolocation feature
38	Number	Well Code Number
39	Extension Type	Well code
40	Deviation Type	Vertical/horizontal/ S-shaped
41	Deviation Number	Deviation Code
42	SA Geodata ID	State Geodata Identifier
43	Situation	Onshore or offshore
44	State	State location
45	Comments	Comments by the SA State Govt.
46	Plot Symbol	Symbol of well block
47	Well ID	Unique Well Identifier
48	Surface Hole/Casing Depth (m)	Surface casing depth
49	Surface Hole/Casing Drill Bit Size (in.)	Surface casing drill bit size
50	Surface Hole/Casing Shoe Depth (m)	Surface casing shoe depth
51	Surface Hole/Casing Diameter (m.)	Surface casing diameter
52	Intermediate Hole and Casing Depth (m)	Intermediate casing depth
53	Intermediate Hole and Casing Drill Bit Size (in.)	Intermediate casing drill bit size
54	Intermediate Hole and Casing Shoe Depth (m)	Intermediate casing shoe depth
55	Intermediate Hole and Casing Diameter (in.)	Intermediate casing diameter
56	Production Hole and Casing Depth (m)	Production casing depth
57	Production Hole and Casing Drill Bit Size (in.)	Production casing drill bit size
58	Production Hole and Casing Shoe Depth (m)	Production casing shoe depth
59	Production Hole and Casing Diameter (in.)	Production casing diameter
60	Surface Cement Volume Cement Used (sacks)	Surface volume cement used
61	Surface Cement Top of Cement Well Completion Report (m)	Surface top of cement well completion report
62	Intermediate Cement No. Cement Stages	Intermediate no. of cementing stages
63	Intermediate Cement Volume Cement Used Lead (Sacks)	Intermediate volume cement used lead
64	Intermediate Cement Volume Cement Used Tail (Sacks)	Intermediate volume cement used tail
65	Intermediate Cement Type Lead	Intermediate cement type lead
66	Intermediate Cement Type Tail	Intermediate cement type tail
67	Intermediate Cement Top of Cement Well Completion Report (m)	Intermediate top of cement well completion report
68	Intermediate Cement Top of Cement CBL (m)	Intermediate top of cement CBL
69	Production Cement No. Cement Stages	Production no. of cementing stages
70	Production Cement Volume Cement Used Lead (Sacks)	Production volume cement used lead

Feature ID	Feature	Description
71	Production Cement Volume Cement Used Tail (Sacks)	Production volume cement used tail
72	Production Cement Type Lead	Type/class
73	Production Cement Density Lead (ppg)	Production cement density lead
74	Production Cement Type Tail	Type/class
75	Production Cement Density Tail (ppg)	Production cement density tail
76	Production Cement Top of Cement Well Completion Report (m)	Production top of cement well completion report
77	Production Cement Log Date	Date log was acquired
78	Production Cement Loggers TOC (m)	Production loggers TOC
79	Production Cement Interpreted Top of Cement CBL (m)	Production interpreted top of cement CBL
80	Production Cement Quality	Interpretation based on report
81	Comments by SA Gov.	Comments by the SA State Govt.
82	Surficial	Depth of surficial formation
83	Eyre Fm	Depth of Eyre Formation
84	Winton Fm	Depth of Winton Formation
85	Tambo	Depth of Tambo Formation
86	Mackunda Fm	Depth of Mackunda Formation
87	Oodnadatta Fm	Depth of Oodnadatta Formation
88	Allaru Mdst	Depth of Allaru Mudstone
89	Toolebuc Fm	Depth of Toolebuc Formation
90	Coorikiana Sst	Depth of Coorikiana Sandstone
91	Wallumbilla Fm	Depth of Wallumbilla Formation
92	Bulldog Sh	Depth of Bulldog Shale
93	Cadna-owie Fm	Depth of Cadnaowie formation
94	Murta Fm	Depth of Murta Formation
95	McKinlay Mbr	Depth of McKinlay Formation
96	Namur Sst	Depth of Namur Sandstone
97	Westbourne Fm	Depth of Westbourne Formation
98	Adori Sst	Depth of Adori Sandstone
99	Birkhead Fm	Depth of Birkhead Formation
100	Hutton Sst	Depth of Hutton Sandstone
101	Poolowanna Fm	Depth of Poolowanna Formation
102	Cuddapan Fm	Depth of Cuddapan Formation
103	Nappamerri GP	Depth of Nappamerri GP
104	Wimma Sst Mbr	Depth of Wimma Sandstone Mbr
105	Paning Mbr	Depth of Paning Mbr
106	Toolachee Fm	Depth of Toolachee Formation
107	Daralingie Fm	Depth of Daralingie Formation
108	Roseneath Sh	Depth of Roseneath Shale

Feature ID	Feature	Description
109	Epsilon Fm	Depth of Epsilon Formation
110	Murteree Sh	Depth of Murteree Shale
111	Patchawarra Fm	Depth of Patchawarra Formation
112	Tirrawarra Sst	Depth of Tirrawarra Sandstone
113	Merrimelia Fm	Depth of Merrimelia Formation
114	Dullingari GP	Depth of Dullingari GP
115	BASEMENT	Depth of basement
116	Last Submission Date	Most recent drilling report submitted on record
117	Co-Formation	Coformation being produced from

Appendix 2

Feature ID	Feature	Description / Formula
A	Date of Last Production	Date when production ended
B	Shut in Years	Days last production reported - Date last production
C	Well Age at Date of Last Reporting Period	Age of the well at the end of last reporting period
D	Spud to Rig Release (5 - 4) - DAYS	Rig release date - Spud date (duration of drilling)
E	Normalized Drill Rate	Total depth/ spud to rig release (meters/d)
F	Number of Casing Sections	Sum of surface, intermediate and production casing sections
G	1 X Casing Section Normalized Drilling Rate	Normalized drilling rate for wells with 1 casing section
H	2 X Casing Section Normalized Drilling Rate	Normalized drilling rate for wells with 2 casing sections
I	3 X Casing Section Normalized Drilling Rate	Normalized drilling rate for wells with 3 casing sections
J	Open Formation	Production liner TOC - Surface/intermediate casing shoe
K	Production Liner (Surface to Bottom)	Production liner depth
L	Surface Or Intermediate Casing Shoe Depth (m)	Surface or intermediate casing shoe depth (m)
M	TOC	Top of cement from CBLs
O	Total number of Zones Exposed	If TOC is deeper than intermediate/production casing creating zonal exposure
P	Risk Code	Risk code based on identified features
Q	Well age cost multiplier	Cost multiplier to risk associated with well age
R	Shut in time cost multiplier	Cost multiplier to risk associated with shut-in time
S	Well depth cost multiplier	Cost multiplier to risk associated with well depth
T	Production casing cost multiplier	Cost multiplier to risk associated with production casing
U	Completion type cost multiplier	Cost multiplier to risk associated with completion type
V	Zonal exposure cost multiplier	Cost multiplier to risk associated with zonal exposure

Section 2: Thesis

ANALYSIS OF SOUTH AUSTRALIAN ONSHORE OIL & GAS WELL DECOMMISSIONING AND POTENTIAL IMPACT ON REGULATORY COMPLIANCE, ENVIRONMENTAL AND CORPORATE RISK

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Abstract

This research aims to improve on the limited understanding related to the increasing portfolio of shut-in or suspended South Australian Oil and Gas wells in the Cooper Eromanga basin. This is accurate for wells drilled up to October 2017 due to a two-year confidentiality period on data for more recent wells when this research analysis commenced in 2019. The increasing portfolio presents a significant potential commercial, regulatory, and environmental risk to the operators that is generally not well understood or quantified.

The results from the analysis provide a better understanding of the growing portfolio of wells, approximation of associated risks and costs together with a framework of a forward-looking abandonment strategy for the basin to manage risk effectively and economically. This is relevant research as there is no clear abandonment strategy from operators that have historically or currently operated wells in the 60-year history of the basin. Furthermore, only limited research has been conducted by the regulators, operators, academia, or other independent government bodies on publicly available data pertaining to these wells.

To understand the risk associated with well integrity, it is important to perform analysis on existing data for all wells that have been drilled, their geology, associated producing formation data, zonal isolation practices, and drilling practices in addition to considering other previously abandoned and suspended wells. An outcome of this research is a unique risk code for each well that amalgamates complexity and associated risk stemming from the analysis of six well parameters. These parameters are well age; shut-in time; well depth; zonal exposure; completion type; and well production geometry. This forms a starting point for quantification, and the number of parameters that can be utilized in this modular method can be expanded as required. The result of this research is a risk code that provides detailed context for each well to enable the efficient building of an abandonment strategy specific to that well.

Further, a cost approximation model was built to quantify the commercial aspects of executing a basin-wide abandonment strategy. This cost was conservatively estimated to be $ 654 Million AUD for all 1511 remaining wells that are yet to be abandoned, between now and the end of well and field life in the basin. The magnitude of this figure should encourage collaboration which could identify technology and optimization to reduce a necessary process that does not yield a commercial return.

Even though there have historically been more than 25 operators in the basin over its 60-year life, over 85% of well ownership is spread between two operators. Based on the analysis of over 100 parameters in more than 2000 wells in the basin, the research shows there is an urgent need to perform a deep joint industry and academic analysis on the basin to assess the constantly increasing risk and associated liability of abandonment. Furthermore, this research shows that by using emerging digital and mechanical technologies it is possible to build more effective, economic, and scalable abandonment strategies compared to the existing time-consuming and expensive methods.

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1. Introduction

Drilling for oil and gas has occurred continuously for more than sixty years in South Australia with over two thousand wells constructed over this period. As all are designed to be producing wells for a finite length of time, there is an increasing number ready for decommissioning.

Well decommissioning, commonly referred to as Plug and Abandonment (P&A), aims to restore the natural integrity of geologic formations that existed prior to drilling. It is a mandatory requirement for all well decommissioning plans to consider the effects of any foreseeable chemical and geological processes with an eternal perspective. Given that, P&A is complicated and costly, particularly where compromised annular isolation exists. Ensuring effective isolation at the decommissioning phase requires well intervention operations. Such interventions are often carried out under high uncertainty as the target wells are likely to be mature assets with limited available knowledge on well conditions or recent intervention history. Consequently, the work scope under these conditions requires significant time and resource allocation.

Annular isolation forms a key part of the restoration process of the natural integrity to eliminate communication between permeable formations behind pipe. In addition, it must prevent fluids from reaching the surface by containing pressure, known as Sustained Casing Pressure (SCP), that persistently rebuilds after depressurization. The consequences associated with compromised annular isolation can negatively impact the environment and a company's reputation, as well as having adverse commercial effects. To avoid this, the process of "cementing" forms the primary means of attaining annular isolation."

Yet, even with best practice in design and execution at the well construction phase, compromised annular isolation is a problem across the industry. Locally, the Government of South Australia, Department of the Premier and Cabinet reported in May 2018 (SAGov, 2018) that it had identified 582 of 2,435 wells reviewed with no observable annular cement between two or more aquifers. This equates to 23.9% of South Australian wells being non-compliant under the 2000 Petroleum and Geothermal Energy (PGE) Act. Additionally, there are wells without adequate information to effectively conclude the well condition.

This research builds on the above finding to investigate relationships pertinent in well construction using comprehensive publicly available databases to improve how wells are designed and constructed. The research also looks at future challenges associated with decommissioning defined in the objectives.

The financial liability associated with the P&A of thousands of onshore South Australian Wells is also calculated based on current industry practices. Given the sheer number of wells involved - thousands locally, millions globally - this is an urgent issue that requires intensive study to achieve the end goal of reducing liability and risk exposure.

1.1 Problem Statement

A review of the publicly available South Australian Cooper Eromanga basin drilled wells was sourced to create a well database. Petroleum Exploration and Production System (PEPS) South

Australia is a web-based system containing a wide range of technical data relevant to the petroleum and geothermal industries.

This database of well information was reviewed to assess the degree of potential commercial exposure and environmental risk due to wells that have been shut-in but not abandoned. The following key findings came out of the review:

- The designed lifespan of a workover or completion can range from anywhere between 10 to 20 years Preliminary analysis identified that 43% of the wells that were shut-in and suspended have been shut-in for over 10 years.
- This statistic shows the importance and urgent need of analyzing and assessing the risk associated to these wells. The decision making around which wells are kept operational, shut-in, or abandoned is an extremely complex process that must consider multiple parameters.
- There is no public record of any intervention activities since the wells were shut-in, presenting a significant degree of uncertainty around the integrity of these wells and other conditions in the wellbore, with the onus lying with the operator.
- The rate of drilling wells far exceeds the rate of abandonment, which indicates that the portfolio of wells that need to be analyzed and their associated risk mitigated grows with time.
- Currently, there is neither a quantified metric to assess this increasing risk nor a forward-looking abandonment strategy to help mitigate potential exposure in place.

As a result of the review, several industry-wide gaps in knowledge were identified in current operations and regulatory construct. The objectives and extended objectives of this project were formulated to address these gaps in knowledge.

1.2 Gaps in Knowledge

Based on the abovementioned review of the existing situation, the following points highlight the current knowledge gaps in the industry:

1. There has been no evaluation of the South Australian Onshore Well database to identify potential commercial, environmental, legal, and regulatory exposure.
2. There is no forward-looking Abandonment Strategy in any of the operating companies in place to mitigate associated risks by prioritizing abandonments of shut-in wells.
3. There is no repository of learning with regard to well integrity and well construction data from thousands of wells that have already been drilled.
4. There is no industry-wide understanding of potential exposure and analogous behavior patterns from specific formations in the Cooper Eromanga basin post abandonment.
5. Given that the design life of completions and workovers executed in the Cooper Eromanga basin is 10-20 years, there is only limited research available to understand the most effective and economic solution to managing well integrity after this period of being shut-in.
6. Given that additional parameters which impact well integrity over time include well age, the length of time the well has been shut-in, the completion complexity prior to

shut-in, and the number of zones exposed that need to be isolated, there has been no prior way to unify this risk for effective decision making.

To address these gaps in knowledge, this research seeks to achieve the objectives identified in section 1.3 below.

1.3 Objectives

Based on the identified knowledge gaps in section 1.2, the key objectives of this research are to:

1. Develop a database capable of defining deviations in well construction to regulatory requirements
2. Develop a unified risk code that amalgamates all key types of operational risk for wells where relevant data is available
3. Based on existing information in the database around well construction and cementing data, identify zonal isolation opportunities
4. Research relevant regulatory compliance and confirm compliance/non-compliance to zonal isolation requirements
5. Quantify the magnitude of the issue by discovering a way to quantify the complexity of these wells and factor them into the cost of executing an abandonment program
6. Research, analyze and discuss potential deterrents to abandonment from an operator and regulatory perspective
7. Analyze the financial implications of deploying such a strategy for wells that are already shut-in and for the overall portfolio (highlighting all reasonable assumptions made)
8. Discuss relevant emerging technology that can be used to execute an abandonment strategy at scale, economically and effectively.

1.4 Project Scope

Geographical Scope: This research will be focused exclusively on South Australian wells that are in the Cooper Eromanga Basin.

Types of Wells in Scope: This research will only focus on onshore oil and gas wells in the Cooper-Eromanga basin. It will have no focus on offshore wells, water, mineral or geothermal wells, or any other basins e.g., Otway. The targeted scope ensures focus on a common geology and well targets to ensure insights are relevant specifically to this data set.

2. Literature Review

Once the database content was consolidated using publicly available data it was arranged into a useable format at which point the literature review was undertaken – Appendix 1. The objective of the review was to assess what had been done to utilize large well construction data sets for abandonment planning at a macro scale.

The papers reviewed are listed below and can be broadly categorized into the following:

- Technology or methods application to achieve P&A
- Commercial and decision making in P&A

Common to many of the papers were references to industry standards from Norsok, UKOOA, and API which also formed part of the literature review.

There were papers identified that attempted to quantify the abandonment liability (NERA report and Alberta Inactive wells) but these did not propose or look at the well characteristics to more clearly define the abandonment issue as completed in this research. The listed papers below have all been reviewed as part of the literature review prior to the research, but have not been referenced as part of this thesis. The inclusion below is to demonstrate the broad range of papers available and none of which touch on the specific research into the wells investigated.

3. Background

3.1 Well Lifecycle

The well lifecycle can be broadly separated into the following phases: exploration; drilling; completion; production; and abandonment. This research focuses on the final phase and uses publicly available data to better quantify the cost of, and design for the abandonment of wells. However, to fully understand the complexities involved in preparing for well abandonment that is compliant with existing regulations, a brief overview of all of the phases in the lifecycle of a well is provided below.

Exploration: This is the first stage for any operator that is considering drilling in an area. Since there is no way to say for sure where new oil and natural gas reservoirs are located, companies use emerging technology to help pinpoint potential resources with ever-improving accuracy. Operations in this phase commence with geologic evaluation to identify subsurface geologic structures where there may be potential for hydrocarbons. This results in reduced uncertainty during the development and construction phases, fewer wells drilled and hence lowered exploration costs. Primary geologic formation data is collected by mapping the surface. More exact information is collected by assessing geologic structures and subsurface rock properties via seismic activities or sonar wave. Many of these technologies can be used to explore additional untapped accumulations in existing fields or to optimize well location and type based on the characteristics of the field. (National Petroleum Council, 2011)

Drilling a well is a highly coordinated event, usually executed by third party drilling contractors. The process is costly and therefore optimization of time is essential, typically involving around the clock operation of the drilling rig. Upon completion of the drilling process, the rig is moved to the next well location, either on the same pad or at a new location based upon the predefined plan. The time needed for drilling an oil or gas well is highly variable, based on the geology of an area, rig capabilities, depth and size of the hole, supply management, down hole information, logging procedures, weather, seasonal changes, and any issues encountered while drilling. As more wells are drilled in an area, the drilling time tends to go down as these factors become better understood and the system is well established. Drilling a single well may take a month or two or be as short as a week to ten days. An operator first drills a hole to a specific minimum distance below the deepest registered domestic water well or drinking water aquifer in the area and follows a standard casing and cementing procedure. Protecting the aquifers from contamination is a major concern of the oil and natural gas industry. Casing is the term used for the pipe, made of steel or high-tech alloys, which is lowered into the hole and cemented into place. There is surface casing, which is used to protect freshwater aquifers. There is also production casing that keeps the hole open so that oil and natural gas can be brought to the surface. (National Petroleum Council, 2011)

Once drilling operations are finished, wells are "completed" for production if the potential value of the recoverable oil and natural gas is greater than the cost of drilling and producing the hydrocarbons. If not, the well is “plugged and abandoned” in accordance with industry standards and federal or state requirements (depending on the location) and the site is restored. Completion is the process of making a well ready to flow for production (or injection). This principally involves preparing the bottom of the hole to the required specifications, running in the production tubing and the associated down hole tools, as well as perforating the casing and stimulating the formation, as required. There can be open hole and cased hole completions, and sometimes the process of running in and cementing the casing is included. The producing formation may also be acidized or fractured to enhance production or injection capacity (National Petroleum Council, 2011).

After a well is drilled and completed, the final work is done at the site for producing from the well. At the well itself, this includes installing a wellhead, or the pieces of equipment mounted at the opening of the well to manage the extraction of hydrocarbons from the underground formation. To collect oil or natural gas from the well and begin to treat it for transportation and sale, field facilities, such as flowlines, the gathering system and treatment equipment, are needed. The wells often produce a complex mixture of oil, liquid hydrocarbons (such as natural gas liquids), gas, water, and solids, varying from location to location. The treating processes separate the different constituents of the mixture, removing those that are non-saleable, and selling the liquid hydrocarbons and gas. Purchasers have contract standards for the oil and gas accepted, often called pipeline quality. For example, oil purchasers typically limit the amount of basic sediment and water (BS&W) to less than one percent. Gas purchasers set limits on water, water vapor, hydrogen sulfide, carbon dioxide, and BTU content. The production techniques will vary depending on the type of reservoir and how long it has been in production. (National Petroleum Council, 2011)

After all the economically recoverable oil and gas has been produced at a well site, or if a well fails to produce (such as a dry hole), the well is plugged and abandoned, and the site is reclaimed. Federal land and state oil and gas agencies have rules that specify how the well is plugged, soil reclaimed, and other environmental and safety protections completed to avoid future problems.

Plugging and abandoning a well involves filling the well casing with cement and removing the wellhead, pump jack, tanks, pipes, and other facilities and equipment. For abandonment of pipelines and flowlines, the lines are flushed, and any remaining fluids are properly disposed of. Near surface lines that could become exposed due to erosion are removed, with deeper lines remaining in place if the overseeing agency approves. If cleaned of materials and provided it can be done safely, leaving the pipeline in place avoids disturbing the surface again. Final well plugging and abandonment of remote wells takes an incredible amount of planning to minimize the environmental impact. Operational steps and mechanical barriers are planned to reduce the amount of equipment needed to haul to the site. All fluids that are recovered are hauled out or injected back into an approved disposal well. By law, all wellheads are cut below ground and removed from the site. (National Petroleum Council, 2011)

3.2 Why focus on Well Construction, Decommissioning and Abandonment?

Subterranean geological formations that are permeable and contain mobile fluids such as water, gas or oil need to be effectively isolated to eliminate against communication between two (or more) zones. It is a relevant issue that forms part of the risk management equation for thousands of SA wells. As Operators will endeavor to implement best practices in well construction, identifying wells that have maintained integrity through the test of time or conversely failed could potentially be used to revise design methodology. Establishing a baseline across the state could subsequently be used to encourage collaboration and the sharing of knowledge to improve performance across the industry.

3.2.1 Environmental and Corporate Risk

Uncontrolled release of fluids to the surface or to subsurface aquifers can have an adverse environmental impact. This can in turn lead to higher remediation costs, penalties, and impact regulator and community perception which form part of an operator's social licence to operate. Communication between zones can also reduce the recoverable reserves and therefore erode the project's value. There are 622 wells in the Cooper Eromanga Basin's South Australian region that have zonal exposure and the potential for communication between zones or aquifer contamination.

A corporation's financial treatment of mature wells ready for decommissioning often projects spend far into the future. The effect being that on Net Present Value abandonment costs have a minimal impact on the balance sheet. This method carries a potential risk whereby a change in regulations requiring a timely decommissioning of inactive wells exposes operators to a significant commercial impact of which few companies would be financially and organizationally positioned to address quickly. Investigation into associated improvements in P&A will benefit operators technically and commercially as well as providing additional regulator insight for potential future regulation changes.

3.2.2 Long Term Consequences of Delays

Time and exposure associated degradation of installed components may further complicate future interventions. The period during which the well is expected to work as required (design life) is exceeded in many cases. Components and barrier elements are more likely to subsequently fail which in turn could result in Health, Safety or Environmental issues. Understanding all aspects of well maturity may yield insight into optimum intervention time for non-producing assets.

3.2.3 Quantifying the Magnitude of the Issue

The significance of the increasing inventory of wells that currently require or will require P&A is dependent on prescriptive regulations. Establishing metrics can provide insight into managing the current liability while also helping to assess the potential impact of any changes in regulations. Furthermore, databases could allow operators to verify their current assumptions.

3.2.4 Opportunity for Technology Application or Development

Current intervention technology and methods could be replaced or complimented through developing technology or new ideas. Identifying commonalities could refine the solution methods and potentially improve practices.

3.2.5 Business Management Impact

There currently exist deterrents to P&A. Current methods are costly and do not provide any revenue to the operator. Therefore, where the HSE risks are manageable, small gradual investment in operational expenditure for monitoring and maintenance over an extended timeframe is preferable as opposed to large one-off capital expenditure associated with decommissioning.

Furthermore, resource allocation using conventional methods to plan and execute P&A requires specialized skillsets and Australia remains an inexperienced player in the field of abandonment (NERA, 2016). There exist significant obstacles to overcome without innovation which begins with a broad understanding of SA well issues.

3.2.6 Taxation Considerations

Taxation treatment relating to P&A is also a deterrent. It does not provide benefits for proactive intervention as "closing-down expenditure in relation to a single production license petroleum project will only be incurred if the whole project is closing down. Closing down of some wells and rehabilitation activities in that area while production from other wells is to continue will not give rise to closing-down expenditure" (ATO, 2018). This legislation only serves to encourage operators to delay expenditure on P&A to recoup the tax benefits when all operations cease. In turn, this leads to non-producing assets often not undergoing P&A significantly beyond their design life while the operator waits for complete project closure.

Identifying opportunities to reduce the cost, simplify the resources required, and potentially promote changes to legislation are therefore possible outcomes of this investigation.

In summary, well construction and associated decommissioning studies proposed in this research impact a broad range of topics with the intention to proactively highlight risks and opportunities in this field of study.

4. Regulatory Compliance

Well abandonment must ensure the environmentally safe isolation of the well, protection of groundwater resources, isolation of the productive formations from other formations, and the proper removal of surface equipment. The outcomes of well abandonment are to:

- Isolate groundwater aquifers within the well from each other and hydrocarbon zones
- Isolate hydrocarbon zones within the well from each other, from groundwater aquifers or from zones of different pressure
- Isolate the surface casing and production casing from open hole
- Place a surface cement plug in the top of the casing
- Recover/remove the wellhead.

In the following section the relevant legislation is presented. The inclusion of the regulation allows for future cross reference and also demonstrates the prescriptive nature of the objectives of well decommissioning.

4.1 Description of Relevant Legislation

The Petroleum and Geothermal Energy Act 2000 was proclaimed on 1 October 2009, to replace the repealed Petroleum Act 2000. The Petroleum Act 2000 was proclaimed on 25 September 2000, to replace the Petroleum Act 1940.

Regulations under associated Petroleum and Geothermal Energy Regulations 2013 do not have overly prescriptive well abandonment requirements. However, the operator is obliged to comply in full with Objective 6 of the

The key aspects of Objective 6 are as follows:

Objective: Minimise loss of aquifer pressure and avoid aquifer contamination

Assessment Criteria:

Producing, Injection, Inactive and Abandoned Wells

- No crossflow behind casing between aquifers, and between aquifers and hydrocarbon reservoirs unless approved by DWLBC (Department of Water, Land and Biodiversity Conservation).

How the above objective can be achieved:

Producing, Injection and Inactive Wells

- Monitoring programs implemented (e.g., through well logs, pressure measurements, casing integrity measurements and corrosion monitoring programs) to assess the condition of the casing and crossflow behind the casing.
- Casing annulus pressures are to be monitored every 2 years.

- For cases where crossflow is detected, a risk assessment incorporating the use of pressure / permeability / salinity data is to be undertaken in consultation with DLWBC & SAALNRM (South Australia Arid Lands Natural Resource Management) Board to determine if lack of cement or poor bond will cause or has caused damaging crossflow which needs to be remediated.

Well Abandonment Activities

- Isolation barriers should be set in place to ensure that crossflow, contamination, or pressure reduction will not occur.
- Barriers are set to meet or exceed the requirements of applicable standards for the decommissioning and abandonment of water bores and abandonment of petroleum wells.
- The placement of isolation barriers will in general be to isolate the groups of formations as listed under comments. The number and placement of barriers may be varied from this standard approach on a case-by-case basis by operator personnel using relevant available data and the SA Cooper Basin Water Pressure and Salinity Module Report (2002), and in consultation with DWLBC.

This objective seeks to protect the water quality and water pressure of aquifers that may potentially be useful as water supplies, and to maintain pressure in sands that may host petroleum accumulations elsewhere. To address this objective, the risks of crossflow between aquifer cells known to be permeable and in natural hydraulic isolation from each other, or where there is insufficient information to determine that they are permeable or in hydraulic communication, must be assessed on a case-by-case basis. If necessary, procedures must be implemented to minimize contamination of the freshwater aquifer cells. In addition, steps must be taken to isolate potential and producing formations from non-producing formations that may deplete the reservoir pressure. The following geological formations are aquifers in the Cooper-Eromanga Basin. They may contain permeable sands which may be in natural hydraulic isolation from each other (from shallowest to deepest), and, in general, isolation should be maintained between the following groups:

1. Eyre
2. Winton
3. Mackunda
4. Coorikiana
5. Cadna-owie
6. Murta (including McKinlay Member)
7. Namur and Adori
8. Birkhead, Hutton, and Poolowanna
9. Cuddapan, Nappamerri Group formations, Walkandi, and Peera formations
10. Toolachee and Daralingie
11. Epsilon, Patchawarra or Mt Toodna or Purni

12. Tirrawarra sandstone or Stuart Range, Merrimelia, Boorthanna, Crown Point formations, and Basement reservoirs.

4.2 Regulator Reporting Requirements

The following sections show relevant extracts from the South Australian legislation to illustrate the prescriptive requirements from the operator to the government when undertaking operations. This information is of high relevance as this forms the data that is publicly available following a 2-year privacy period. The full extract of the regulation has not been included; rather selected extracts in sections 4.2.1 to 4.2.5. Specifically in sections 4.2.4 the regulation on abandonment is shown, and what is evident is that it does not form a very prescriptive procedure.

4.2.1 Open Hole Wells

1. A licensee who undertakes any drilling on any day must furnish to the Minister a **daily drilling report** in accordance with the requirements of these regulations.
2. A daily drilling report—
   a. Must relate to a period not exceeding 24 hours, calculated from the end of the period reported on in the immediately preceding daily drilling report (unless the report is the first report for the well); and
   b. Must be provided to the Minister within 12 hours after the end of the period to which it relates.
3. A daily drilling report must include—
   a. The name and number of the well
   b. A report number or the number of days from spud
   c. The time and date of well spud and rig release
   d. The depth of the well at the end of the reporting period (in metres)
   e. Information on operations carried out during the reporting period
   f. The mud-log for the reporting period
   g. Resource show descriptions
   h. A description of the formations, and the depth of any geological formation tops, encountered during the reporting period
   i. Well logs acquired during the reporting period
   j. The drill stem test intervals and results, including recoveries and the API gravity of any liquid hydrocarbons recovered during the reporting period, and the resistivity of any water recovered during the reporting period
4. A copy of a report under this regulation will be available for public inspection when the relevant well completion report is made available for such inspection.
   However, the location, spud date, rig release date, total depth, datum heights and status of a well may be made available to the public at any time.
5.

Well Completion Report requirements – Regulation 40

1. A licensee who undertakes any drilling must furnish to the Minister, within 6 months after rig release, a **well completion report** in accordance with the requirements of these regulations.
2. A well completion report must include—
    a. The name and number of the well; and
    b. A summary page or pages, located at the beginning of the report, which set out in a concise form basic information relating to the well found in the report; and
    c. A plan that shows—
        i. The location of the well relative to a horizontal control point and a benchmark established not more than 200 metres from the site of the well
        ii. The latitude and longitude of the well in GDA 94 values, computed within accuracy levels approved by the Minister
        iii. Any permanent reference marks established in accordance with these regulations; and
        iv. The direction of true north
        v. Any other well and all roads, access tracks, public utilities or substantial buildings or other structures within 300 metres of the site of the well, and any significant topographical, environmental, or cultural features
        vi. Where applicable, the boundaries and legal description of the section of land within which the well is situated
    d. The name of any drilling contractor
    e. The spud date, the date of rig release, and the total depth drilled (to drillers and loggers' depths, in metres)
    f. A summary of the lithologies encountered during the drilling, and a summary of the geological formations taken to have been encountered during drilling
    g. A composite log, formulated to a scale comparable with the wireline logs used in connection with the drilling, that includes the following:
        i. The bit records
        ii. The penetration rates
        iii. The casing records
        iv. A lithological summary
        v. Geological formation tops
        vi. Representative open hole logs
        vii. Sidewall core points
        viii. Palaeontological analysis results
        ix. Hydrocarbon shows
        x. The drill-stem test intervals and results
        xi. Core intervals and recoveries
        xii. The log analysis result; and
    h. Core and sidewall sample descriptions, and an analysis of these
    i. Relevant petrographic descriptions
    j. The palaeontological analysis results and interpretation

k. The formation test reports, charts and interpretation
l. Log interpretations
m. Details of hole sizes, casings and cementing that has been undertaken
n. Details of well completion or abandonment
o. A velocity survey
p. A geophysical interpretation of the target structure at relevant horizons

3. For the purposes of sub-regulation (2), all depth references for a well must be in metres.

A copy of a report under this regulation will be available for public inspection after the expiration of two years from the date of rig release.

4.2.2 Cased Hole Wells

1. A licensee who undertakes any drilling on any day must furnish to the Minister a **daily drilling report** in accordance with the requirements of these regulations.
2. A daily drilling report—
   a. Must relate to a period not exceeding 24 hours, calculated from the end of the period reported on in the immediately preceding daily drilling report (unless the report is the first report for the well); and
   b. Must be provided to the Minister within 12 hours after the end of the period to which it relates.
   c. A daily drilling report must include—
      i. The name and number of the well.
      ii. A report number or the number of days from spud.
      i. The time and date of well spud and rig release.
      ii. The depth of the well at the end of the reporting period (in metres).
      iii. Information on operations carried out during the reporting period.
      iv. The mud-log for the reporting period.
      v. Resource show descriptions.
      vi. A description of the formations, and the depth of any geological formation tops, encountered during the reporting period.
      vii. Well logs acquired during the reporting period.
      viii. The drill stem test intervals and results, including recoveries and the API gravity of any liquid hydrocarbons recovered during the reporting period, and the resistivity of any water recovered during the reporting period.

A copy of a report under this regulation will be available for public inspection when the relevant well completion report is made available for such inspection.
However, the location, spud date, rig release date, total depth, datum heights and status of a well may be made available to the public at any time.

Well Completion Report requirements – Regulation 40

1. A licensee who undertakes any drilling must furnish to the Minister, within 6 months after rig release, a **well completion report** in accordance with the requirements of these regulations.
2. A well completion report must include—
    a. The name and number of the well; and
    b. A summary page or pages, located at the beginning of the report, which set out in a concise form basic information relating to the well found in the report; and
    c. A plan that shows—
        i. The location of the well relative to a horizontal control point and a benchmark established not more than 200 metres from the site of the well
        ii. The latitude and longitude of the well in GDA 94 values, computed within accuracy levels approved by the Minister
        iii. Any permanent reference marks established in accordance with these regulations; and
        iv. The direction of true north
        v. Any other well and all roads, access tracks, public utilities or substantial buildings or other structures within 300 metres of the site of the well, and any significant topographical, environmental, or cultural features
        vi. Where applicable, the boundaries and legal description of the section of land within which the well is situated
    d. The name of any drilling contractor
    e. The spud date, the date of rig release, and the total depth drilled (to drillers and loggers' depths, in metres)
    f. A summary of the lithologies encountered during the drilling, and a summary of the geological formations taken to have been encountered during drilling
    g. A composite log, formulated to a scale comparable with the wireline logs used in connection with the drilling, that includes the following:
        i. The bit records
        ii. The penetration rates
        iii. The casing records
        iv. A lithological summary
        v. Geological formation tops
        vi. Representative open hole logs
        vii. Sidewall core points
        viii. Palaeontological analysis results
        ix. Hydrocarbon shows
        x. The drill-stem test intervals and results
        xi. Core intervals and recoveries
        xii. The log analysis result; and
    h. Core and sidewall sample descriptions, and an analysis of these
    i. Relevant petrographic descriptions
    j. The palaeontological analysis results and interpretation

k. The formation test reports, charts and interpretation
l. Log interpretations
m. Details of hole sizes, casings and cementing that has been undertaken
n. Details of well completion or abandonment
o. A velocity survey
p. A geophysical interpretation of the target structure at relevant horizons

3. For the purposes of sub-regulation (2), all depth references for a well must be in metres.

A copy of a report under this regulation will be available for public inspection after the expiration of two years from the date of rig release.

Quarterly cased-hole well-activity report – Regulation 41 from

1. A licensee who undertakes any activity on a cased-hole well in any quarter must furnish to the Minister, within 30 days after the end of the quarter, a **quarterly cased-hole well activity report** in accordance with the requirements of these regulations.
2. A quarterly cased-hole well activity report must include—
   a. The name and number of the well; and
   b. The dates on which any activity occurred; and
   c. Information (in a form determined by the Minister) on all pressure tests, recompletions, perforations, fluid sampling and cased hole logging activities conducted during the quarter.
3. A copy of a report under this regulation will not be available for public inspection.

Activity notification—low level official supervision – Regulation 18 (Minister of Energy and Mining, 2019)

1. Notice of activities requiring low level official supervision is to be given to the Minister at least 21 days before the proposed commencement of the activities.
2. A notice under sub regulation (1) must comply with the requirements of regulation 20.

Activity notification—High level official supervision – Regulation 19
http://legislation.sa.gov.au/LZ/C/R/PETROLEUM AND GEOTHERMAL ENERGY REGULATIONS 2013.aspx (Minister of Energy and Mining, 2019)

1. An application for the Minister's approval for activities requiring high level official supervision is to be given to the Minister at least 35 days before the proposed commencement of the activities.
2. A notice under sub-regulation (1)—
   a. Must include, or be accompanied by, detailed information on the licensee's proposals in respect of the operator assessment factors.
   b. Must comply with the requirements of regulation 20.
3. The Minister must, in determining whether to grant an approval under section 74(3)*(a)* of the Act, consider the operator assessment factors.

4. The Minister must not grant an approval under section 74(3)*(a)* of the Act unless or until the Minister is satisfied that the requirements of Part 12 of the Act have been complied with.

Detailed activity information – Regulation 20 (Minister of Energy and Mining, 2019)

1. A notice under regulation 18(1) or 19(1) must include, or be accompanied by, the following information or material:
    a. The licence number and the name of the licensee; and
    b. A description of the relevant activity; and
    c. Information on the proposed location of the relevant activity, using co-ordinates in the GDA 94 datum (which may be in digital format), and including a map of the relevant area showing the proposed location of the relevant activity and significant topographical, environmental, and cultural features; and
    d. The full name and business address of any contractor who will be involved to a significant degree in carrying out the activity
    e. The proposed commencement date and the estimated duration of the activity
    f. The name and address of the owner of the relevant land, a declaration concerning compliance with Part 10 of the Act and a copy of any notice provided under that Part, and (if relevant) information on any scheme or process that will be put in place for giving or providing notices or information to owners of the land as the activity progresses; and
    g. An assessment as to whether the relevant activity is covered by an existing statement of environmental objectives under Part 12 of the Act; and
    h. If the relevant activity involves a geophysical survey—
        i. Proposed geophysical techniques
        ii. The length or area of the survey (in kilometres or square kilometres)
        iii. In the case of a seismic survey—the energy source proposed to be used and a list of proposed line names
    i. If the relevant activity involves well drilling—
        i. The type of well to be drilled; and
        ii. The proposed well name; and
        iii. The expected depth of any well; and
        iv. A geological prognosis; and
        v. Maps showing significant structural horizons; and
        vi. Information on primary and secondary targets, and an estimate of the hydrocarbon potential of each target; and
        vii. Information on any relevant evaluation program, including a program for acquiring cuttings samples according to the expected geological formations
        viii. A target weight for each cutting sample to be provided to the department.

2. The notice must include the full name, business address and telephone number of a person who can be contacted about the matters contained in the notice.
3. The Minister may require that a licensee provide further information or material to ensure that the department has comprehensive information on the proposed activities.
4. If a requirement is imposed under sub-regulation (3), the licensee must not commence the relevant activities until the Minister is satisfied that appropriate information has been provided.
5. The Minister may, if the Minister thinks fit, publicly release information on the location and type of any activity to be carried out under a licence.

4.2.3 Well Abandonment Timing

4.2.3.1 Abandonment following Drilling

Following the drilling of a well and testing and evaluation of its potential, a decision is made on whether to proceed with production of the well or to abandon it. If a decision is made to abandon the well the following steps are undertaken:

1. Plugs are set to isolate all formations that have hydrocarbons
2. Plugs are set across separate aquifers
3. Plugs are set across the surface casing shoe and intermediate casing shoe (if present)
4. A plug (typically 30 m) is set at the surface prior to cutting off the surface
5. An abandonment marker is posted.

The well site is then cleaned up and reinstated as described in section 4.2.5 Site Rehabilitation.

4.2.3.2 Abandonment following Production

1. Identify permeable zones containing hydrocarbons, freshwater, and saline water. Prepare a plugging summary that is designed to prevent mixing of formation fluids (to be approved by the appropriate regulatory authority, if required).
2. For practical reasons, only the permeable formations that are thicker than 0.5m should be considered significant enough to be considered, except in South Australia where the provisions of SEO 6 are mandatory regardless of the thickness of the permeable zone.
3. Set cement plugs in the open hole.
4. Set and verify a cement plug across the shoe in line with relevant regulations.
5. Set surface cement plug as per regulations after ensuring that the fluid to be left in the casing contains corrosion inhibitor.
6. When the rig has been moved, install the P & A Marker Plate.

4.2.4 Well Abandonment Components

4.2.4.1 Aquifer Isolation

Regulatory requirements dictate that the isolation procedure will prevent any mixing of hydrocarbon and water producing zones. For the Cooper-Eromanga basin, a generic plugging and abandonment strategy was developed based on Objective 6 of the Statement of Environmental Objectives. Formation tops are identified using wireline logs recorded at the time of well completion. Where wireline logs are not available, tops will be identified through cased/open hole logs. This process of reviewing logs forms a part of the regulatory documentation required prior to the commencement of operations. Based on this information and formation isolation plans, an agreement can be reached between the regulator and the operator. Following this, the abandonment procedure is allowed to commence.

Zone	Plug	Remarks	SEO 6
Winton		Plug required across top Mackunda if not isolated by casing else plug across casing shoe only	This objective seeks to protect the water quality and water pressure of aquifers that may potentially be useful as water supplies, and to maintain pressure in sands that may host petroleum accumulations elsewhere. To address this objective, the risks of cross flow between aquifer cells known to be permeable and in natural hydraulic isolation from each other, or where there is insufficient information to determine that they are permeable or in hydraulic communication, must be assessed on a case by case basis and procedures implemented to minimize the fresh water aquifer cells from contamination, and isolate potential and producing formations from formations that may deplete the reservoir pressure when not on production.
Mackunda			
Oodnadatta		Plug across all Coorikiana if present & permeable as indicated by MLL	
Coorikiana			
Bulldog			
Cadna-owie		Plug across top Cadna-owie if no Coorikiana plug	
Murta		Plug top Murta to top Namur	
Namur			The following geological formations are aquifers in the Cooper Eromanga Basins. They may contain permeable sands which may be in natural hydraulic isolation from each other (from shallowest to deepest) and in general isolation will be maintained between these groups:
Westbourne			
Adori			
Birkhead		Plug across all Birkhead Effectively isolates Hutton	• Eyre; • Winton, • Mackunda; • Coorikiana; • Cadna-owie; • Murta (including McKinlay Member) • Namur, Adori, • Birkhead, Hutton, Poolowanna, • Cuddapan; Nappamerri Group formations, Walkandi and Peera Peera formations. • Toolachee; Daralingie; • Epsilon, Patchawarra or Mt Toodna or Purni; • Tirrawarra sandstone or Stuart Range, Merrimelia, Boorthanna Crown Point formations and Basement reservoirs.
Hutton			
Nappamerri		Plug to isolate top Nappamerri from Hutton	
Toolachee		Plug across top Toolachee	
Roseneath			
Epsilon		Plug across top Epsilon	
Murteree			
Patchawarra			**Note:** Crossflow (if it occurs), should not compromise the long term sustainability of a particular resource.
Tirrawarra Sst		Plug across top Tirrawarra	If Tirrawarra absent, require Basement plug + Patchawarra plug if Epsilon absent.
Pre-Permian			

Figure 1: Aquifer Isolation

(Live.com. (2021). [online] Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.energymining.sa.gov.au%2F__data%2Fassets%2Fexcel_doc%2F0010%2F259759%2F20181108_-_Cooper-Eromanga_Basin_Abandonment_seo_check_v2.xls [Accessed 6 Dec. 2021].

4.2.4.2 Removal of Spools

When performing the following procedure, wellhead equipment should be handled assuming that it is suitable for a refit. Regardless of condition, the Bradenhead should be removed, protectively packed, and prepared for return to the supply base or equipment providers yard for a final decision on whether the item is to be refit or disposed of.

4.2.4.3 Surface Casing

When abandonment has been completed and the blowout preventer (BOP) has been removed, the Bradenhead can be removed in one of the following two ways:

1. If not welded Back off the Bradenhead, or
2. Cut the surface casing a minimum of 150 mm below the Bradenhead

The casing should be cut approximately halfway between the landing base and the Bradenhead.

4.2.4.4 Standard P&A Marker Plate Format

- The riser pipe should be a minimum of 2” OD welded to the base plate fixed to Surface Casing stub
- The top of the ID plate to be 1.8 meters above natural surface (after cellar filled in)
- The ID plate to be approximately 500 mm wide x 350 mm high (20” x 14”) with well data bead welded as shown below.

4.2.5 Site Rehabilitation

- Any water remaining in the Turkey’s Nest is to be completely pumped out so that the maximum amount of plastic pit liner can be recovered. The recovered liner is to be used on the next well location as protection between the shaker tank and the sump.
- If utilised, the rathole and mousehole should be filled to the level of the lease surface and compacted. Care is required in filling the rat- and mouseholes to ensure that they are filled and not bridged off.
- To eliminate the chance of future collapse, the rathole and mousehole should be hand filled with unconsolidated, uncompacted granular “sandy” materials, and then rubber-tyre rolled to ensure that the fill is compact.
- The cellar should be filled in those cases where a temporary cellar ring has been used and is removed at the end of the well, or if the well has been plugged and abandoned. On locations where a permanent cellar has been installed and the well not plugged and abandoned, the cellar is not to be filled in, but the supplied cellar grating should be installed and firmly attached utilising the bolts supplied.
- All waste materials are to be removed from the site and returned to the Waste Management Depot (depending on states) for correct disposal. Any exposed or re-usable plastic which is lining the area by the shaker tank should be removed and disposed of properly.

- All other exposed plastic should be cut off below the surface level to be covered once the sump is backfilled. When required, a well identification plate (Marker Plate) should be fabricated and securely installed where it is clearly visible.
- The site should be cleared of all equipment and materials. This clean-up is generally performed after the sump has dried, so it can be a considerable time after the well has been drilled.
- The sump is fenced during this time. On locations built without a sump, the final clean-up can be done as soon as practical after the drilling rig moves off the location.

5. Well Construction Overview

Well construction is composed of the drilling and completion steps prior to production (Petrowiki, 2019) designed such that well objectives, as set by the subsurface engineers to produce, inject, or monitor, are met. Well construction aims to ensure "Well integrity" defined to be the "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well" (NORSOK, 2013). It is a consideration at all stages as defined below (Hopmans, 2015):

- ***Basis of Design Phase*** *- identifies the probable safety and environmental exposure to surface and subsurface hazards and risks that can be encountered during the well life cycle. Once identified, these hazards and risks are assessed such that control methods of design and operation can be developed in subsequent phases of the well life cycle.*
- ***Design Phase*** *identifies the controls that are to be incorporated into the well design, such that appropriate barriers can be established to manage the identified safety and environmental hazards. The design addresses the expected, or forecast, changes during the well life cycle and assures that the required barriers in the well's design are based on risk exposure to people and the environment.*
- ***Construction Phase*** *defines the required or recommended elements to be constructed (including rework/repair) and verification tasks to be performed to achieve the intended design. It addresses any variations from the design which require a revalidation against the identified hazards and risks.*
- ***Operational Phase*** *defines the requirements or recommendations and methods for managing well integrity during operation.*
- ***Intervention Phase*** *(including work-over) defines the minimum requirements or recommendations for assessing well barriers prior to, and after, a well intervention which requires breaking the established well barrier containment system.*
- ***Abandonment Phase*** *(decommissioning) defines the requirements or recommendations for permanently abandoning a well.*

This research investigates the construction phase with potential lessons to be carried into the design and abandonment phases.

5.1 Well Construction Data – Background

Approximately 3,000 South Australian Oil and Gas wells mostly located in the Northwest of the state (shown in Figure 16 below) will be included in this research. The data was selected as it has numerous differing data types consolidated into a single database. The variety allows for analysis seeking correlations that would not ordinarily be considered and is modular allowing for the expansion of the project as required or conversely focusing on a particular area.

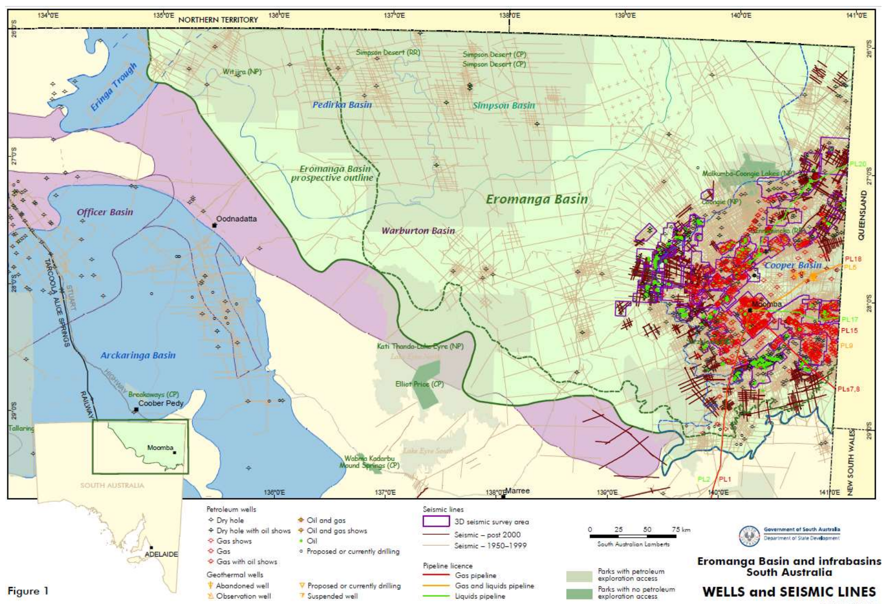

Figure 2: Northwest South Australia Wells Location (SAGov, 2018)

The available data has been separated into the following four (4) categories:

- Well Geometry and Tubulars
- Well Targets and Intersected Formations
- Cementing
- Well Integrity & Abandonment Compliance

Each of the four categories listed above contains a table of data for each well. In the following sections the content is introduced, and examples are provided of insights gained from high level preliminary analysis. Table 3 below shows examples of the data available.

Table 1: Example of available Well Data

Well Name	Designated set of words by which a particular well is known, addressed, or referred to
Operator	The individual, company, trust, or foundation responsible for the well
Spudded	Date at which drilling begins

Rig Release	Date at which drilling has conducted last operation
Status RR	The situation or condition the well is left at rig release (e.g., Abandoned, Producing)
Current Status	Situation or condition at present time (e.g., producing, shut-in)

The following table shows the ownership of wells in the state. Which operators have to bear the responsibility for P&A work, and in what percentage, would depend on the nature of field development, which is often as a joint venture.

Table 2: Breakdown of Operator Well Ownership

Operator	Number of Wells	Operator	Number of Wells
Santos Ltd	1195	Strike Energy Ltd	4
Delhi	319	Ultramar	4
Beach Energy Ltd	87	Bridge	3
Senex Energy Ltd	53	Pursuit	3
Beach Petroleum Ltd	29	Ahava Energy Pty Ltd	2
Stuart Petroleum Ltd	29	Eagle Bay Resources NL	2
Torrens Energy Ltd	25	Green Rock Energy Ltd	2
Victoria Petroleum NL	21	Origin Energy Resources	2
Linc Energy	17	SADME	2
Innamincka Petroleum	15	Scopenergy Limited	2
Geothermal Resources Ltd	8	Acer Energy Ltd	1
Boral Energy Resources	7	Cooper Energy NL	1
Geodynamics	7	Eden Energy Ltd	1
Great Artesian Oil & Gas Ltd	6	Flinders	1

Operator	Number of Wells	Operator	Number of Wells
Adelaide Energy Ltd	4	Oil Company of Australia	1
Alliance	4	Panax Geothermal Ltd	1
Drillsearch Energy Ltd	4	PNC Australia	1
Petratherm Ltd	4	Strike Oil NL	1
SAGASCO	4	*Note: Includes Geothermal Wells	

This research is to identify relationships between all the data and the above is an example of what can be learned by data manipulation. The subsequent sections are not to provide the detailed results of this study rather to provide background and understanding what it is hoped to achieve.

5.2 Well Construction Data – Well Geometry and Tubulars

The oil and gas industry has developed commonly used hole geometry programs allowing standardized sized tools for drilling and completions. The well geometry is designed to allow for economic production of a pay zone. It should be sized with respect to a pay zone's flow potential, with allowance for accommodating problems while drilling and be capable of running necessary equipment. Once the pay zone sizing is understood a bottom-up approach to well design allows selection of tubulars for safe drilling and isolation.

This often involves multiple bit sizes, and casing sizes (as defined below) and often requires more than one type of bit size/casing size per well. Available data includes all "Surface Hole and Casing"; "Intermediate Hole" and "Casing and Production Hole and Casing".

Table 3: Examples of Well Geometry Data

Depth (m)	Distance from the top/surface to the bottom of the hole
Drill Bit Size (in.)	External diameter size of the cutting mechanism used to drill hole
Casing Shoe Depth (m)	Depth of the bottom of the casing string
Casing Diameter (in.)	External diameter of the pipe (casing) ran in the hole

5.3 Well Construction Data – Cementing

There exist two broad categories of cementing, "Primary" and "Remedial". Primary Cementing provides for the following (Smith, 1989):

- Restriction of fluid movement between formations (zonal isolation)
- Bonding and support of the casing
- Protection of the casing from corrosion
- Prevention of blowouts by quickly forming a seal
- Protection of the casing from shock loads in drilling deeper
- Sealing off of zones of lost circulation or lost zones

Remedial cementing is commonly done to rectify issues or faults associated with the primary cement job. Remedial cementing is an additional cost which can be reduced or eliminated by the successful design, planning and execution of primary cementing.

Both primary and remedial cementing aim to isolate formation fluid from potential flow zones, an integral element in ensuring well integrity. The cement deployed forms a physical barrier which is designed to maintain zonal isolation throughout the well lifecycle.

Publicly available data varies in quality and content dependent on the well completion reporting available. However, for most wells the information shown in Table 6 is available.

Table 4: Example Cementing Data

No. Cement Stages	Can be continuous single stage; lead and tail or more
Volume Cement Used Lead (Sacks)	The volume of the first and usually less dense cement pumped during primary cementing for zonal isolation
Volume Cement Used Tail (Sacks)	The volume of cement following the lead which covers the lower section of the wells and is typically of a higher density
Cement Type Lead	Classification/Type of lead cement
Cement Density Lead (ppg)	The degree of compactness of the first cement stage
Cement Type Tail	Classification/Type of tail cement
Cement Density Tail (ppg)	The degree of compactness of the following cement typically higher than the lead density
Top of Cement Well Completion Report (m)	Recorded cement top recorded in the final report provided by the operator
Log Date	Date at which the detailed record of the measurements taken to confirm the proper placement of cement between the formation and the casing (s)
Interpreted Top of Cement CBL (m)	Recorded cement top based upon interpretation of log results

Cement Quality	The standard of the cement measured against a distinctive attribute

This information can be used to confirm if cement type selection for standardized application is within acceptable depth/temperature criteria. For example, a specific class of cement is limited by depth/temperature/pressure and sulphate content. Using these limits, correct cement selection can be crosschecked, and further impacts investigated where poor application has been observed.

Standardization of cementing practices began in 1937 when the American Petroleum Institute (API) established a committee to study cements used in oil and gas wells (Diaz, 2017). With cement laboratories already developing tests on cement for oil well application the period of 1937 -1950 led to new developments and a code was first drafted in 1948 – API Code 32.

API Spec 10A Cement and Materials is the most recent evolution. It forms part of other applicable standards and recommended practices that have become necessary due to the varied environments in which oil and gas operations occur. For example, the two standards below have been developed for deep water exploration and the need for lightweight cements respectively.

- API RP 10B-3 (ISO 10426-3) Recommended Practice on Testing of Deep-water Well Cement Formulations
- API RP 10B-4 (ISO 10426-4) Recommended Practice on Preparation and Testing of Foamed Cement Slurries

In South Australia, API cements are common, and these can be classed into eight (8) categories, Class A-H, as shown in Table 7.

Table 5: API Cement Category Data (ref)

Name	Applicable Depth	Application Temperature (°F)	Slurry Weight (lbm/gal)	Notes
Class A	0 – 6,000 ft	80 – 170	15.6	Only applicable when special properties are not required
Class B	0 – 6,000 ft	80 – 170	15.6	Applicable in moderate (type 1) to high sulphate (type 2) environments
Class C	0 – 6,000 ft	80 – 170	14.8	Applied when high early strength is required Applicable in moderate (type 1) to high sulphate (type 2) environments
Class D	6,000 – 10,000 ft	170 – 260	16.4	Applicable to moderately high temperature conditions Applicable in moderate (type 1) to high sulphate (type 2) environments

Name	Applicable Depth	Application Temperature (°F)	Slurry Weight (lbm/gal)	Notes
Class E	10,000 – 16,000 ft	170 – 290	16.4	Applicable under conditions of high temperatures and pressures Applicable in moderate (type 1) to high sulphate (type 2) environments
Class F	10,000 – 16,000 ft	230 – 320	16.2	Applicable under conditions of extremely high temperatures and pressures Applicable in moderate (type 1) to high sulphate (type 2) environments
Class G	0 – 8,000 ft	80 – 200	15.8	Can be used with accelerators and retarders to cover a wide range of depths and temperatures Applicable in moderate (type 1) to high sulphate (type 2) environments
Class H	0 – 8,000 ft	80 – 200	16.4	Can be used with accelerators and retarders to cover a wide range of depths and temperatures Applicable in moderate (type 1) to high sulphate (type 2) environments

Each class of cement contains proportions of one of four (4) compounds providing the characteristics which in turn give the limitations and capability to adapt. These compounds are shown in Table 8 below.

Table 6: Cement Composition (ref)

Compound	**Tricalcium Aluminate**	**Tricalcium Silicate**	**B-dicalcium Silicate**	**Teracalcium Aluminoferrite**
Formula	**3CaO-Al2O3**	**3CaO-SiO2**	**3CaO-SiO2**	**4CaO-Al2O3-Fe2-O3**
Standard Designation	**C3S**	**C2S**	**C3A**	**C4AF**
A	53	24	8+	8
B	47	32	5-	12
C	58	16	8	8
D & E	26	54	2	12
G & H	50	30	5	12

Adjustments to the compounds listed above can modify the characteristics of the cement as required, for example:

- **Increasing Early Strength:** Increasing the C3S content, grinding finer
- **Better Retardation**: By controlling C3S and C3A content and grinding coarser
- **Low heat of hydration**: By limiting the C3S and C3A content
- **Resistance to sulphate attack**: By limiting the C3A content

By introducing accelerators, retardants, and other additives the behavior and application of the classes of cements can be adjusted.

Non-API cements, specialized products developed by oil and gas service companies for specific applications, are also used. For example, Pozmix is formed by mixing Portland cement with pozzolan (ground volcanic ash) which provides for less expensive lightweight cement often used at shallower depths. All are engineered and designed to achieve the goals of primary and remedial cementing. However, even with strict adherence to all relevant standards in design and implementation the potential for compromised well integrity remains.

Investigation into the data aims to :

- Determine depth application as compared to industry recommendations for each class of cement
- Determine if any correlation exists between cementing success and factors such as stage cementing, density, and cement class with respect to borehole size and environmental conditions (depth/temperature/pressure)
- Compare historical cementing practices to current methods

There also exists an opportunity to use the well cement bond logs (CBLs) for further insight. This is expected to be included for wells, but it is not envisioned to form part of this study as reviewing thousands of logs and digitizing this information would be beyond the capability of a single researcher.

5.4 South Australia Well Construction Data – Geology, Well Targets and Intersecting Formations

In South Australia, oil and gas can be found in the Jurassic, Triassic, and Permian geological periods. As wells are drilled, they intersect various sands which are captured in the well completion reports for each well. These recorded depths can be used for benchmarking purposes. These formation tops, shown below

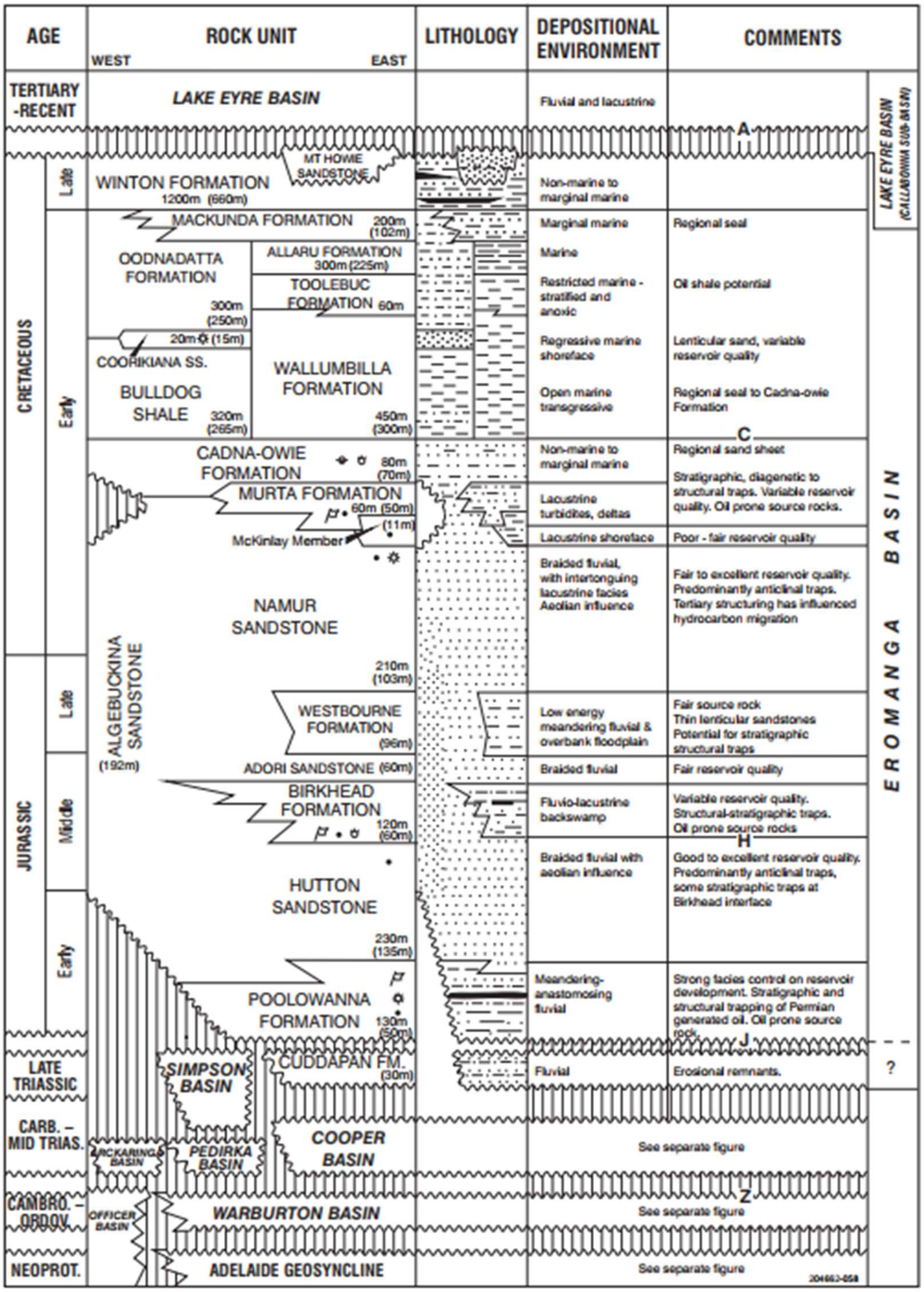

Figure 3: South Australian Geology

sarigbasis.pir.sa.gov.au. (n.d.). *Webtop Log In*. [online] Available at: https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/plans/sarig1/image/DDD/204662-058.

Analysis of well targets and intersected formations data shows how drilling depths change over time. For example, when drilling for Permian Targets such as the Toolachee and Daralingie sands, operators in South Australia have to drill significantly deeper than was the case ten, twenty or thirty years ago.

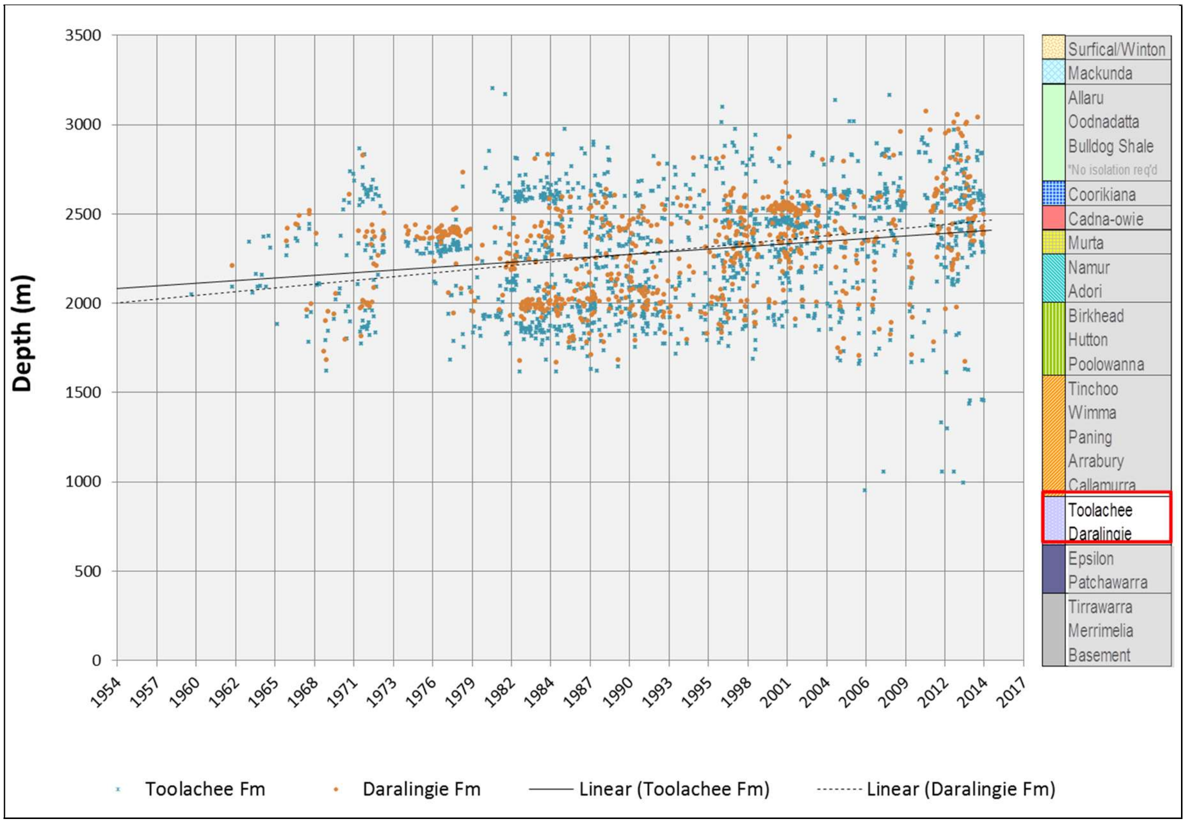

Figure 4: Toolachee and Daralingie Formation Drilling Depth Data

This finding above contrasts with the later Jurassic Targets in the Birkhead/Hutton Poolowanna and Namur/Adori sands below which have been shallower over time as shown in Figure 19 and Figure 20 below.

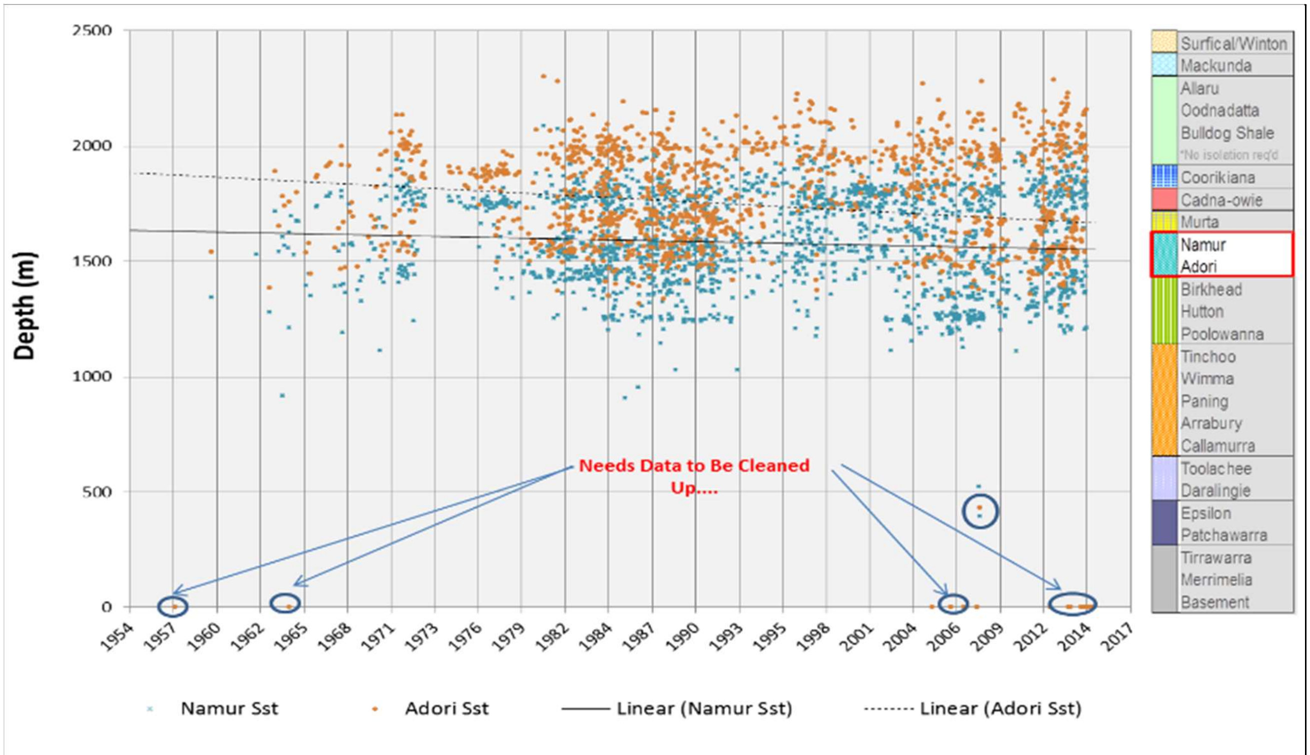

Figure 5: Namur and Adori Formation Drilling Depth Data

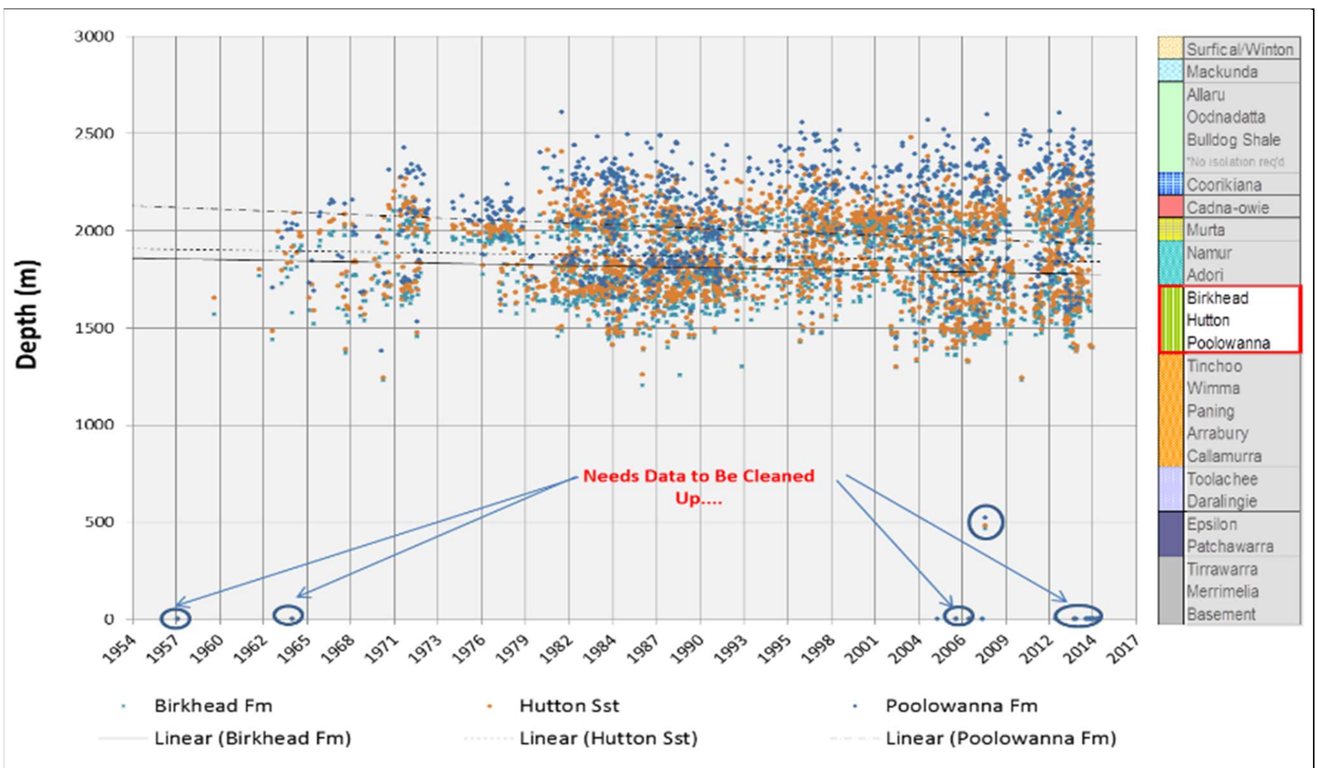

Figure 6: Birkhead, Hutton and Poolowanna Formation Drilling Depth Data

5.5 Abandonment Standards

5.5.1 Barrier Philosophy

All penetrated zones with the potential to flow that have been identified as requiring isolation will be isolated from each other and the surface by a minimum of one permanent barrier. A permanent barrier is classified as requiring 100 ft / 30 m (MD) of good cement except where:

- flow zones are less than 30 m apart
- placing a 30 m cement plug is not practical in which case the length may be reduced under a risk assessment to as low as is reasonably practical. The reduced length cement plug must be designed to withstand the expected maximum pressure differential across it, and efforts should be made to utilise completion techniques/ technologies to ensure the best chance of achieving a high-quality cement plug.

Two permanent barriers from the surface are required for hydrocarbon bearing zones. The criteria for these barriers are as follows:

- The quality of this barrier is required to be the same as the primary barrier as a minimum.
- The secondary barrier for one zone may double as a primary barrier for another provided the isolation is appropriately designed for each individual zone.
- Two barriers can be replaced with a combination barrier which requires 200 ft / 60 m (MD) of good cement (see Figure 21). The internal cement plug must be adjacent annular good cement over a cumulative length of 60 m of overlap.

5.5.2 Barrier Verification

The following barrier verification requirements are from ***Oil & Gas UK Well Decommissioning Guidelines Issue 6 June 2018*** which state that it can take up to 150 m of cement to ensure placement of 30 m of consistent good quality cement and classify as a single barrier.

- Barrier installation is to be documented in detail in daily rig and service company reports.
- The strength development of the cement slurry should be confirmed via pre-job lab tests or modelling and monitoring of surface samples during the job as an indicator.
- Barrier position should be confirmed by tagging where required.
- Cased hole barrier integrity should be verified by a pressure test or negative inflow test where possible. Pressure tests are to be to a minimum of 500 psi above the maximum expected pressure differential (accounting for potential re-charge of the formation).
  - Pressure test value may be reduced if it exceeds casing burst/collapse strengths (accounting for wear allowance, damage, corrosion, etc.) or there is a risk to the integrity of the primary casing cement.

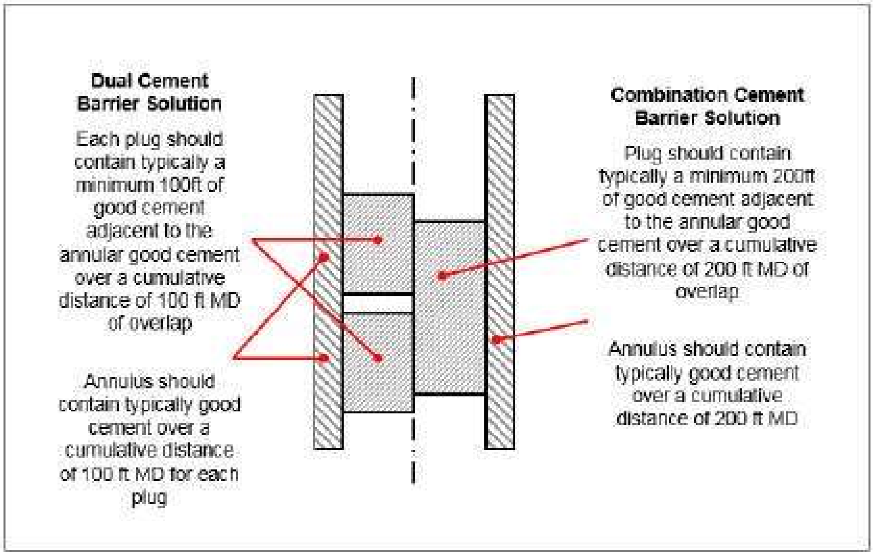

Figure 7: Barrier Philosophy

Code of Practice For the construction and abandonment of petroleum wells and associated bores in Queensland Petroleum and Gas Inspectorate Version 2. (2019). [online] Available at: https://www.resources.qld.gov.au/__data/assets/pdf_file/0006/1461093/code-of-practice-petroleum-wells-bores.pdf. Page 42, Section 3.16.3

Where a sealing mechanically set platform (i.e., packer with plug set in the tail pipe or bridge plug) or a previously set cement plug is being used as a base for a cement plug and has been pressure tested to the criteria outlined above, a tag and pressure test of the cement barrier is not required unless:

- The mechanically set platform fails a pressure test or is not pressure tested due to concerns of compromising the integrity of the platform
- The cement job does not go to plan and requires a tag and pressure test to verify the position and integrity of the plug to determine whether remediation is required
- The plug is deemed a critical isolation and additional verification is warranted to confirm the position and integrity of the barrier

▪ Annular barrier integrity will be verified through a combination of the following:
  - Pressure test or negative inflow test where possible
  - Records from original cementing operations such as:
    - Well Integrity reporting
    - Logs
  - Where a sealing formation has collapsed in on a casing string and the bond log is interpreted to indicate positive isolation of zones from one another behind pipe, perforation and a cement squeeze should be attempted to enhance the

integrity of the behind pipe barrier and confirmed permeability of the collapsed formation is sufficiently low enough to prevent crossflow of zones requiring isolation (relevant to shallow behind pipe isolations).

- If new technologies are utilised, such as a Perforate – Wash - Cement tool or section milling, it may be necessary to drill out a cased-hole cement plug to re-log behind pipe and confirm isolation, particularly if there are concerns with the cementing operation. Plug location and length should consider the potential need to repeat the isolation technique up hole whilst being of sufficient length to effectively isolate the required zones. Such new technologies may be required for behind pipe isolation in the event the original cement is of poor quality.

6. Methodology, Insights and Discussion

This research is based on a publicly available dataset that contains all the raw data that will be analyzed in a structured manner. This dataset contains information for 2436 wells across a multitude of operators in the Cooper-Eromanga basin in South Australia. It is critical to note that only oil and gas wells are considered in this analysis. All coal seam gas (CSG) wells, water wells and other types of wells are filtered out. Table 9 shows the type of information that is available in the database with its associated interpretation and description below.

Table 7: Raw Data Features

Feature ID	Feature	Description
1	Well	Name of the well
2	Operator	Company responsible for operating the well
3	Province	South Australian Province where well is located
4	Spudded Date	Date when Drilling starts
5	Rig Release Date	Date when Drilling is completed
6	Class	Class of well - Exploration, Appraisal or Development
7	Type	Type of well - Oil, Gas or Dry
8	Status RR	Status at Rig Release - Abandoned, Suspended, Plugged & Suspended or Single Completion
9	Review Date	Date at which last review on the well was performed
10	Completion Status	Completion Status of the well and type of Completion
11	Completion Date	Date when Completion was performed

Feature ID	Feature	Description
12	Driller/Rig	Service provider responsible for Drilling activities
13	Primary Objective	Priority target formations to be produced from
14	Secondary Objective	Second priority target formations to be produced from
15	License Type	Type of licence - Exploration, Production or Retention
16	Licence Number	Licence number
17	Current PPL	Current Petroleum Production Licence Number
18	Start Depth (Metres)	Depth at which Drilling Starts
19	Total Depth (Metres)	Depth at which Drilling Ends
20	Ground Level (Metres)	Datum level used for measurement
21	Kelly Bushing (Metres)	Depth from Kelly Bushing relative height
22	Deviation	Deviation type - Vertical, Low Angle, High Angle, Horizontal
23	Height Datum	Reference scale for object height calculation
24	GDA Latitude	Geocentric Latitude
25	GDA Longitude	Geocentric Longitude
26	GDA Latitude Degrees	Geolocation Feature
27	GDA Latitude Minutes	Geolocation Feature
28	GDA Latitude Seconds	Geolocation Feature
29	GDA Longitude Degrees	Geolocation Feature
30	GDA Longitude Mins	Geolocation Feature
31	GDA Longitude Seconds	Geolocation Feature
32	GDA Easting	Geolocation Feature
33	GDA Northing	Geolocation Feature
34	GDA Zone	Geolocation Feature
35	Datum	Geolocation Feature
36	X	Geolocation Feature
37	Y	Geolocation Feature
38	Number	Well Code Number
39	Extension Type	Allocation used in PEPS
40	Deviation Type	Vertical, Horizontal Deviated
41	Deviation Number	Deviation Code
42	SA Geodata ID	State Geodata Identifier
43	Situation	Onshore or offshore
44	State	State Location

Feature ID	Feature	Description
45	Comments	Comments by the SA state govt
46	Plot Symbol	Symbol of what block the well is in
47	Well ID	Unique well Identifier
48	Surface Hole/Casing Depth (m)	Surface Casing Depth
49	Surface Hole/Casing Drill Bit Size (in.)	Surface Casing Drill Bit Size
50	Surface Hole/Casing Shoe Depth (m)	Surface Casing Shoe Depth
51	Surface Hole/Casing Diameter (in.)	Surface Casing Diameter
52	Intermediate Hole and Casing Depth (m)	Intermediate Casing Depth
53	Intermediate Hole and Casing Drill Bit Size (in.)	Intermediate Casing Drill Bit Size
54	Intermediate Hole and Casing Shoe Depth (m)	Intermediate Casing Shoe Depth
55	Intermediate Hole and Casing Diameter (in.)	Intermediate Casing Diameter
56	Production Hole and Casing Depth (m)	Production Casing Depth
57	Production Hole and Casing Drill Bit Size (in.)	Production Casing Drill Bit Size
58	Production Hole and Casing Shoe Depth (m)	Production Casing Shoe Depth
59	Production Hole and Casing Diameter (in.)	Production Casing Diameter
60	Surface Cement Volume Cement Used (sacks)	Surface Volume Cement Used
61	Surface Cement Top of Cement Well Completion Report (m)	Surface Top of Cement Well Completion Report
62	Intermediate Cement No. Cement Stages	Intermediate No. of Cementing stages
63	Intermediate Cement Volume Cement Used Lead (Sacks)	Intermediate Volume Cement Used Lead
64	Intermediate Cement Volume Cement Used Tail (Sacks)	Intermediate Volume Cement Used Tail
65	Intermediate Cement Type Lead	Intermediate Cement Type Lead
66	Intermediate Cement Type Tail	Intermediate Cement Type Tail

Feature ID	Feature	Description
67	Intermediate Cement Top of Cement Well Completion Report (m)	Intermediate Top of Cement Well Completion Report
68	Intermediate Cement Top of Cement CBL (m)	Intermediate Top of Cement CBL
69	Production Cement No. Cement Stages	Production No. of Cementing stages
70	Production Cement Volume Cement Used Lead (Sacks)	Production Volume Cement Used Lead
71	Production Cement Volume Cement Used Tail (Sacks)	Production Volume Cement Used Tail
72	Production Cement Type Lead	First cement pumped across production casing
73	Production Cement Density Lead (ppg)	Production Cement Density Lead
74	Production Cement Type Tail	Secondary cement pumped across production casing
75	Production Cement Density Tail (ppg)	Production Cement Density Tail
76	Production Cement Top of Cement Well Completion Report (m)	Production Top of Cement Well Completion Report
77	Production Cement Log Date	Date when data was aquired
78	Production Cement Loggers TOC (m)	Production Loggers TOC
79	Production Cement Interpreted Top of Cement CBL (m)	Production Interpreted Top of Cement CBL
80	Production Cement Quality	Interpretation of the Cement bond log with regards to quality of cement job
81	Comments by SA Gov.	Comments by the SA state govt
82	Surficial	Depth of Surficial Formation
83	Eyre Fm	Depth of Eyre Formation
84	Winton Fm	Depth of Winton Formation
85	Tambo	Depth of Tambo Formation
86	Mackunda Fm	Depth of Mackundar Formation
87	Oodnadatta Fm	Depth of Oondnadatta Formation
88	Allaru Mdst	Depth of Allaru Mudstone
89	Toolebuc Fm	Depth of Toolebuc Formation
90	Coorikiana Sst	Depth of Coorikiana Sandstone
91	Wallumbilla Fm	Depth of Wallumbilla Formation

Feature ID	Feature	Description
92	Bulldog Sh	Depth of Bulldog Shale
93	Cadna-owie Fm	Depth of Cadnaowie formation
94	Murta Fm	Depth of Murta Formation
95	McKinlay Mbr	Depth of McKinlay Formation
96	Namur Sst	Depth of Namur Sandstone
97	Westbourne Fm	Depth of Westbourne Formation
98	Adori Sst	Depth of Adori Sandstone
99	Birkhead Fm	Depth of Birkhead Formation
100	Hutton Sst	Depth of Hutton Sandstone
101	Poolowanna Fm	Depth of Poolowanna Formation
102	Cuddapan Fm	Depth of Cuddapan Formation
103	Nappamerri GP	Depth of Nappamerri GP
104	Wimma Sst Mbr	Depth of Wimma Sandstone Mbr
105	Paning Mbr	Depth of Paning Mbr
106	Toolachee Fm	Depth of Toolachee Formation
107	Daralingie Fm	Depth of Daralingie Formation
108	Roseneath Sh	Depth of Roseneath Shale
109	Epsilon Fm	Depth of Epsilon Formation
110	Murteree Sh	Depth of Murteree Shale
111	Patchawarra Fm	Depth of Patchawarra Formation
112	Tirrawarra Sst	Depth of Tirrawarra Sandstone
113	Merrimelia Fm	Depth of Merrimelia Formation
114	Dullingari GP	Depth of Dullingari GP
115	BASEMENT	Depth of Basement
116	Last Submission Date	Most recent drilling report submitted on record
117	Co-Formation	Co-formation being produced from

Before proceeding to the analysis, it was important to make this dataset more consumable and create variables that could be used formulaically to derive insights. As a result, a new raw dataset was created where some of the 117 features were used as variables to create new formulaic variables that could then be analyzed arithmetically and statistically to derive valuable insights. This new dataset had the following features which together with the original dataset would be used for analysis.

Table 8: Refined Raw Data Features and Calculated Variables

Feature ID	Feature	Description / Formula
A	Date of Last Production	Date when production ended

Feature ID	Feature	Description / Formula
B	Shut-in Years	Days last Production reported - Date Last Production
C	Well Age at Date of Last Reporting Period	Age of the well at the end of last reporting period
D	Spud to Rig Release (5 - 4) - DAYS	Rig Release Date - Spud Date (Duration of Drilling)
E	Normalized Drill Rate	Total Depth/Spud to Rig Release (meters/d)
F	Number of Casing Sections	Sum of Surface, Intermediate and Production casing sections
G	1 X Casing Section Normalized Drilling Rate	Normalized Drilling Rate for wells with 1 casing section
H	2 X Casing Section Normalized Drilling Rate	Normalized Drilling Rate for wells with 2 casing sections
I	3 X Casing Section Normalized Drilling Rate	Normalized Drilling Rate for wells with 3 casing sections
J	Open Formation	Production Liner TOC - Surface/Intermediate Casing Shoe
K	Production Liner (Surface to Bottom)	Production Liner Depth
L	Surface or Intermediate Casing Shoe Depth (m)	Surface or Intermediate Casing Shoe Depth (m)
M	TOC	Top of Cement from Cement Bond Logs
N	Total number of Zones Exposed	If TOC is deeper than intermediate/ production casing creating zonal exposure
O	Risk Code	Risk code based on identified features
P	Well age cost multiplier	Cost Multiplier to risk associated with Well Age
Q	Shut-in time cost multiplier	Cost Multiplier to risk associated with Shut-in time
R	Well depth cost multiplier	Cost Multiplier to risk associated with Well Depth
S	Production casing cost multiplier	Cost Multiplier to risk associated with Production Casing
T	Completion type cost multiplier	Cost Multiplier to risk associated with Completion Type
U	Zonal exposure cost multiplier	Cost Multiplier to risk associated with Zonal Exposure
V	Total Cost	Total cost based on identified features

6.1 Abandonment Activity Sizing and Potential

Out of all the wells in the basin, the scope of this project was limited to oil and gas wells only. This eliminated all mineral, coal seam gas, and water wells that were drilled in the basin. Further, wells that had no rig release information or status updates were also removed from the analysis due to inadequate data quality. This resulted in a starting point of 2346 wells prior to any analysis. Preliminary filtering showed the breakdown of the 2346 wells as shown in Figure 22.

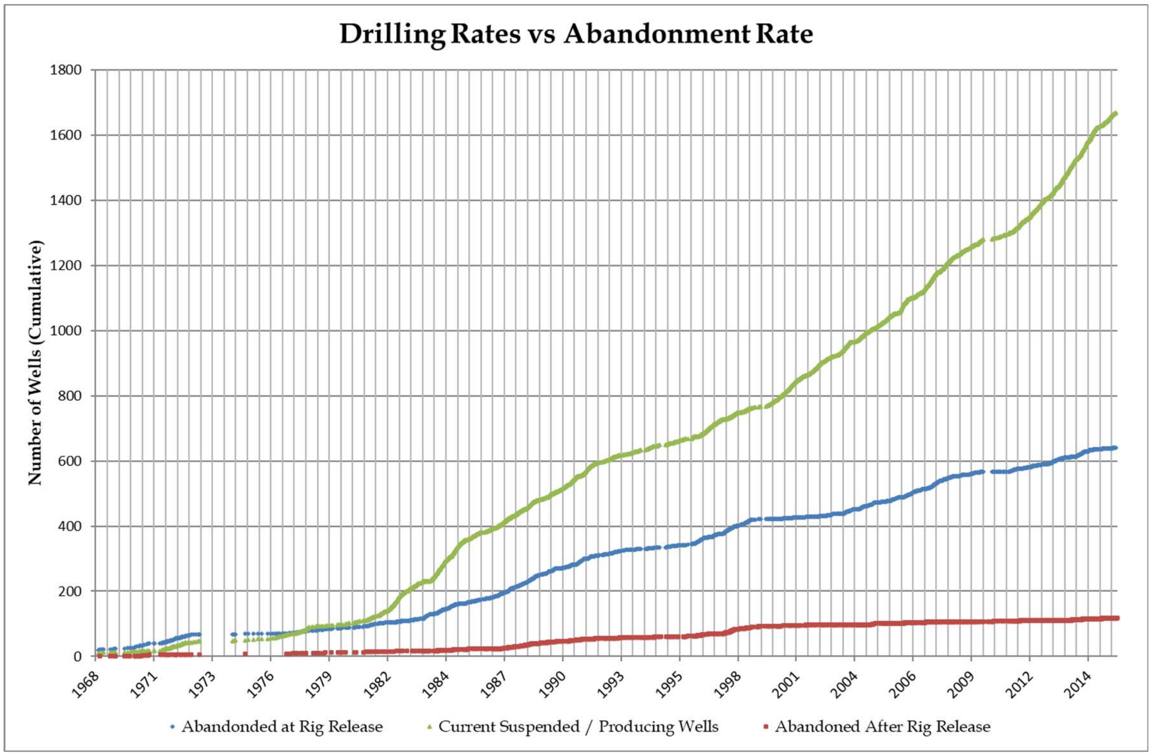

Figure 8: Drilling Rates vs Abandonment Rates in South Australia's Cooper-Eromanga Basin

From a total of 648 abandoned wells, 525 were abandoned at rig release as 'dry holes'. This data is represented in the above figure in blue. A further 123 wells were abandoned due to reaching end of life. As a result, the number of active wells to be considered stood at 1698. Upon further breakdown, 187 of these are wells that have been temporarily plugged and suspended or suspended. A visual breakdown of this information can be seen in Figure 23 and Figure 24.

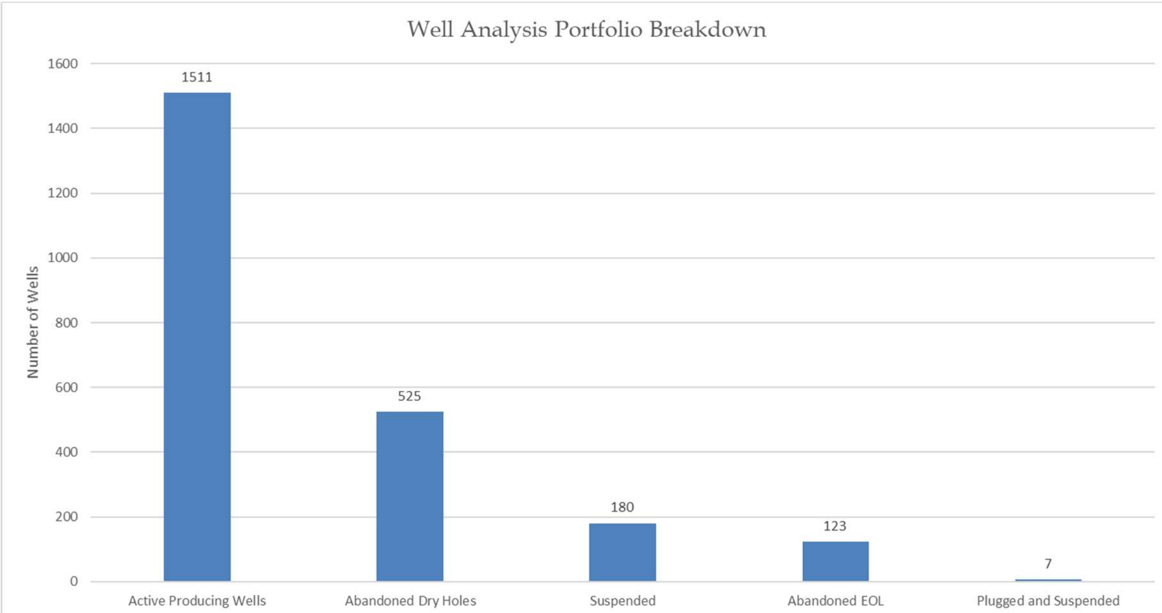

Figure 9: Well Analysis Portfolio Breakdown

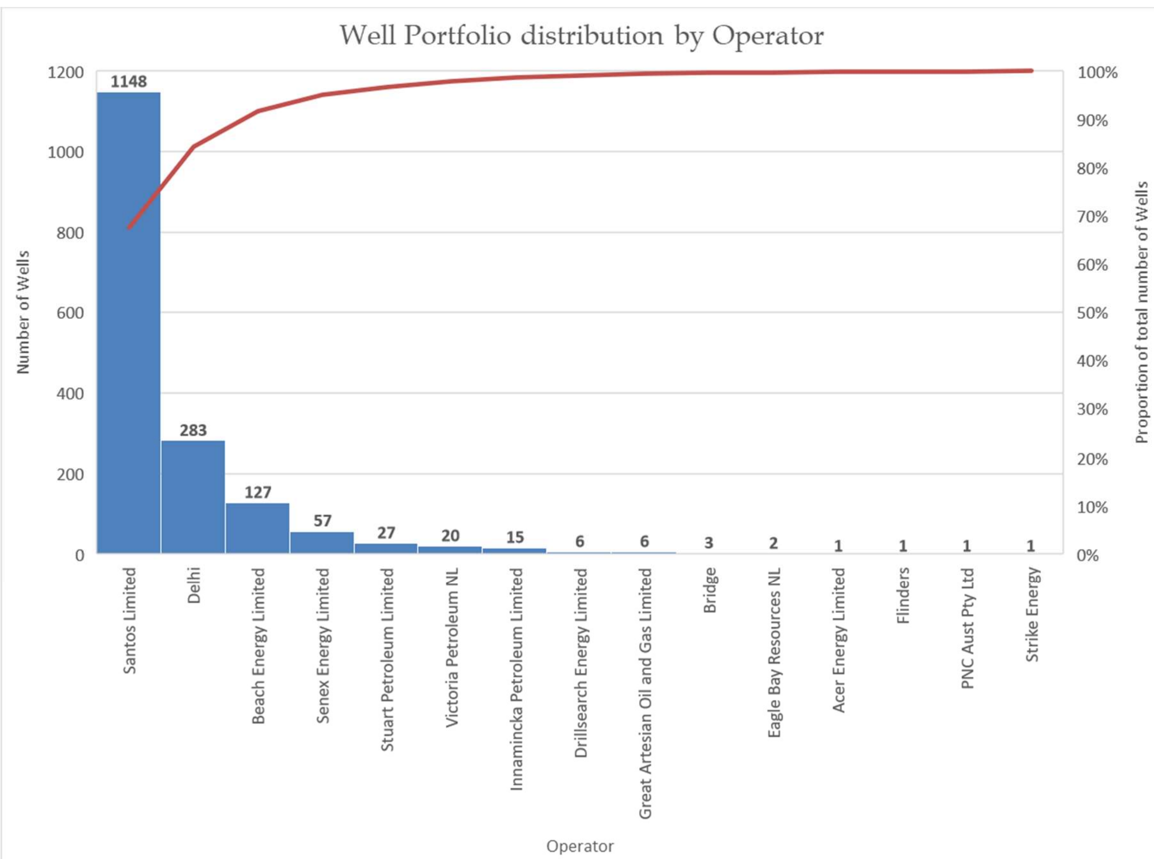

Figure 10: Well Portfolio Distribution by Operator

As observed in Figure 24, almost 70% of these wells are owned and operated by Santos Limited, followed by Delhi and Beach Energy, all of whom would benefit greatly from this research and a forward-looking Well Abandonment Strategy. This does not account for Beach Energy's acquisition of Delhi. Furthermore, it is important to note that many wells in the basin are operating as joint ventures and hence the associated risks and costs are to be distributed between the relevant parties. However, that data is private and confidential and hence not included in this analysis.

6.2 Features contributing to potential commercial and environmental risk for the operator

The following six features are used in this research to define well risk, with the understanding that this would not be an exhaustive analysis as a part of the abandonment strategy.

6.2.1 Well and Production Geometry

Figure 25 gives an indication of the evolution of well geometry over time.

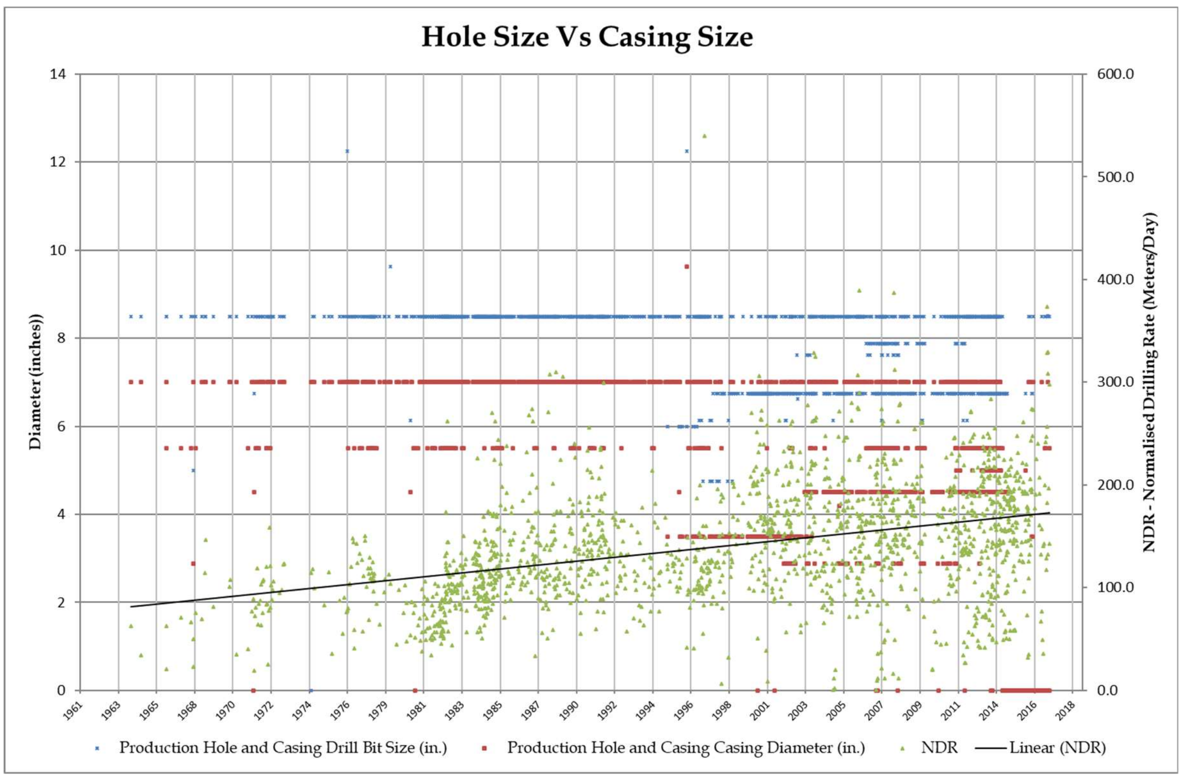

Figure 11: Wellbore Geometry evolution with time

The Primary Y-axis on the left measures outer diameter in inches and the secondary Y-axis on the right measures normalized drilling rates measured in metres/day. The X-axis measures the time component of this evolution. The blue data points show the outer diameter of the drilled hole (hence the drill bit), and the red data points represent the outer diameter of the production casing. It becomes apparent with time that historical wells prior to 1995 were predominantly drilled with 8.5" hole and completed with 7" production casing; there are some instances of 5.5” but they are less frequent. After 1995, 6.75” drilling becomes more common with smaller production casing becoming common (2.875”, 3.5”, 4.5”, 5.5”). Drilling of 8.5” holes continue to accommodate for 7” completions. The green data points show how the normalized drilling rates (NDR) have changed with time, and although there is not a clear polynomial equation to model this, the scatter trend does show an increment in NDR over time implying an improvement in drilling performance with reducing hole and casing size.

In seeking to quantify the level of risk from a well bore geometry perspective wells can be categorized into a low, medium, high risk of integrity failure distribution, as follows:

- All wells that are over 5.5” production casing OD are low risk wells – 50% of total wells are in this category.
- All wells that are between 4.5” to 5.5” production casing OD are medium risk wells – 20% of wells are in this category.
- All wells that are less than 4.5” in production casing OD are high risk wells – 10% of wells are in this category.

6.2.2 Well Age

The age of the well is a significant indicator towards risk associated with potential well bore integrity issues as the downhole equipment and activities have a limited design life ranging from 10-20 years. Thus, older wells represent a greater risk. As seen in Figure 26 below, 842 wells, representing about 49% of total active wells, are over 20 years old.

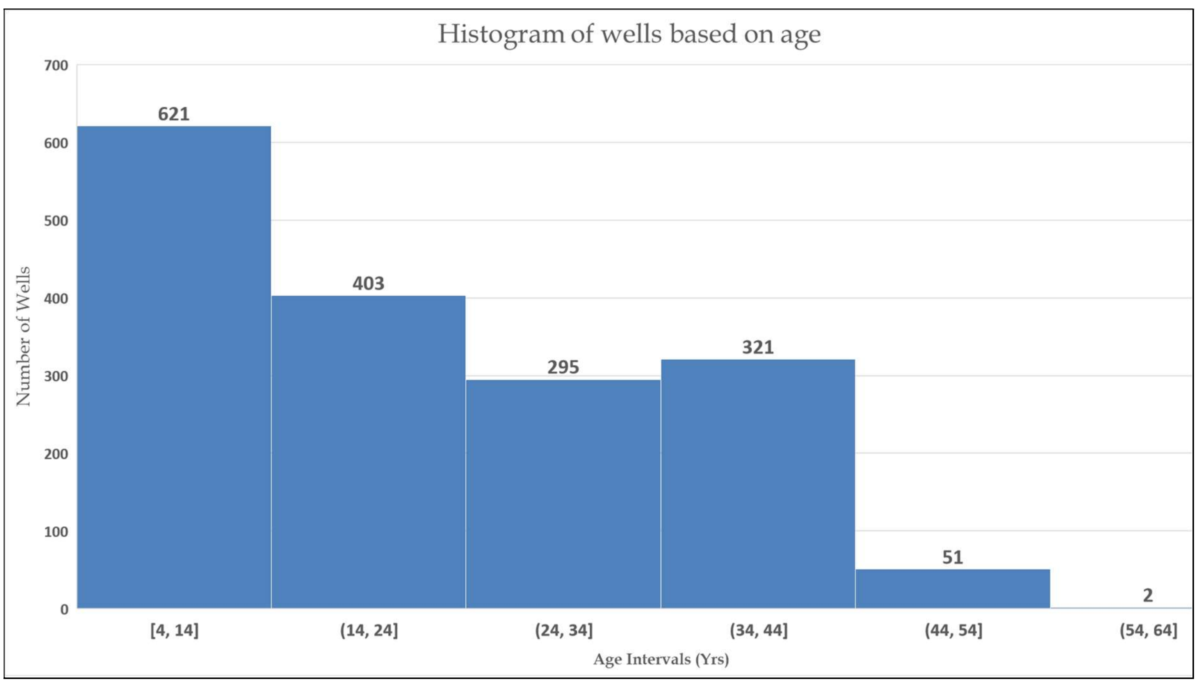

Figure 12: Well Age Histogram

6.2.3 Shut-in Time

Shutting in a well is stopping production from that well indefinitely despite the well still having capacity to produce. Sometimes, wells are shut-in for safety reasons due to unidentifiable behavior in the well bore; however, the most common reason for a shut-in is because a particular well becomes uneconomic to produce from as the cost of extraction is greater than the price of oil and/or gas that would be produced from it. This process is most impacted by non-well related circumstances such as oil price changes, geopolitics, logistical constraints (including storage constraints due to pipeline/ trucking closures etc.) amongst other external issues. Once a well is shut-in, it can be brought back online at any time once conditions for production are favourable. However, once a well has been left shut-in for an extended period, the operator concerned will not know the key conditions involved in bringing a well back online. These include well integrity, potential aquifer contamination, hydrocarbon surface shows, or formation communication between two formations. Obtaining information on these areas requires an intervention to be performed. However, well intervention is only performed when the well in question needs to be brought back online. Thus, the longer wells have been shut-in, the greater the commercial and environmental risk they carry. The commercial risk pertains to legal liabilities that arise from surface hydrocarbon shows (gas leaks from the top of a shut-in well) that cause a potential accident or liabilities that pertain to aquifer contamination resulting in polluted and unusable water for the local communities. These events can have associated environmental implications, leading to serious disruptions in the local ecosystem.

In relation to this research, Figure 27 shows the number of wells currently shut-in for specified numbers of years.

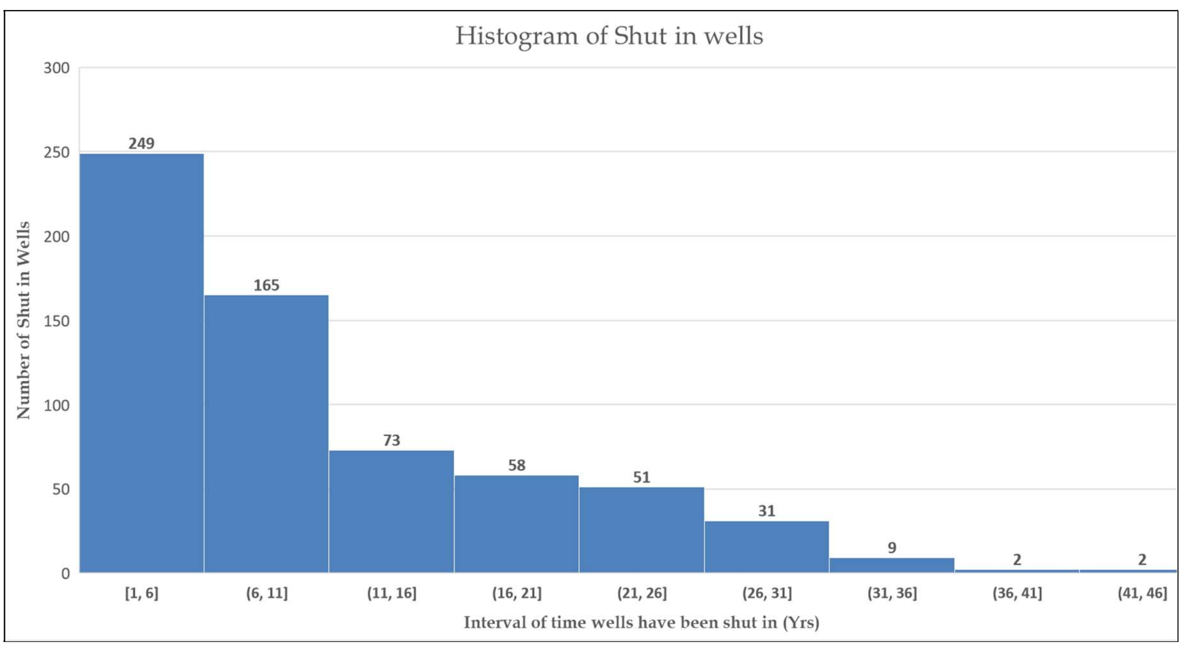

Figure 13: Shut-in time Histogram

As seen in Figure 27 above, there are 640 “active”, non-abandoned wells that have been shut-in, representing 38% of the total active wells. Of these, 391 of the shut-in wells have been shut-in for over six years, a significant 61% of the shut-in wells. More importantly, 256 of the total number of shut-in wells have been in shut-in for over 10 years. If the design life of the completion and associated wellbore equipment is 10-20 years, and the last intervention was immediately before shutting the well in, then 40% of total shut-in wells are operating beyond their design life. This number will increase with time if no action is taken. This lack of action on suspended wells adds to the risk profile of the wells over time.

Given the high volume of wells, it was critical to develop a priority list of wells that needed to be addressed first and gain an understanding of the implications of no action being taken and model how risk would change with time. To do this, well age was plotted graphically against shut-in times as seen in Figure 28 below. The vertical axis represents well age, and the horizontal axis represents shut-in time. This implies that data points that are on the Y-axis are currently producing wells. This plot includes all wells that are not abandoned and have reported production data.

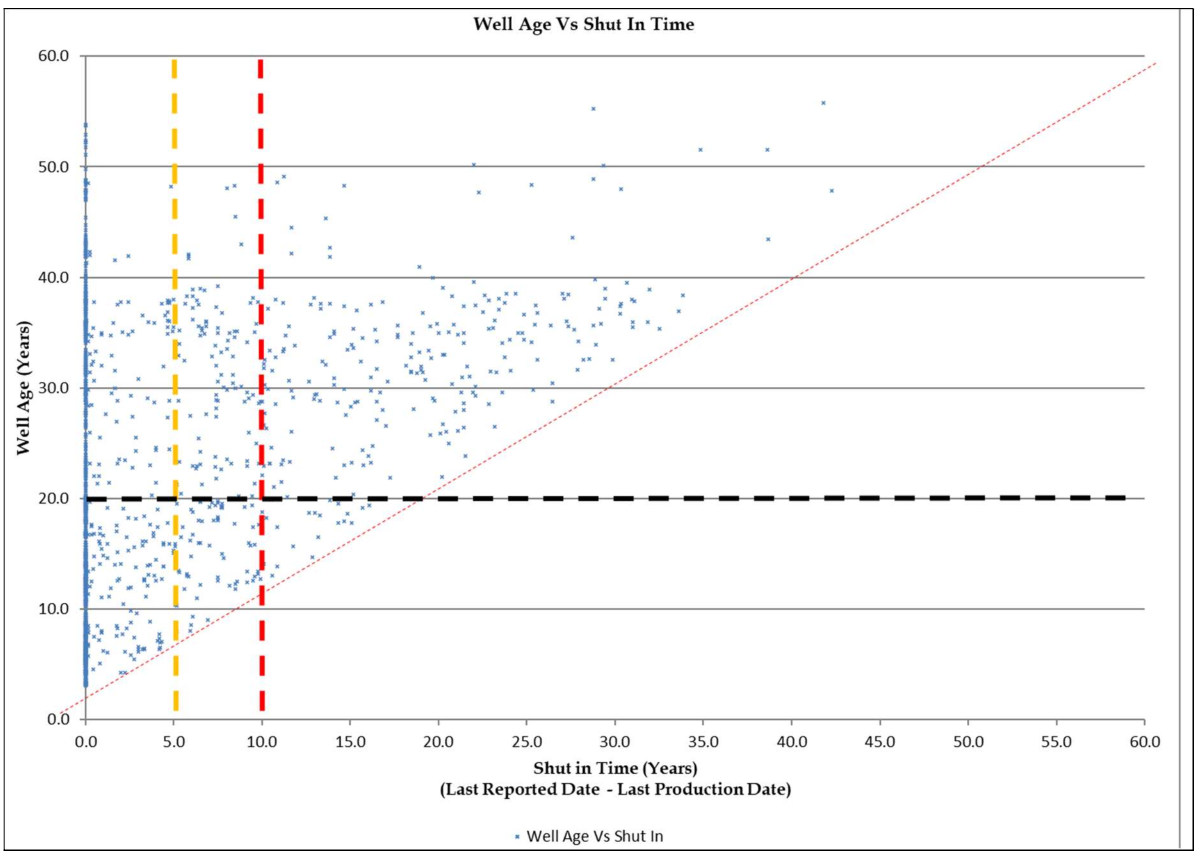

Figure 14: Well Age vs Shut-in time

Due to the design life of downhole equipment ranging from 10-20 years, wells less than 20 years old are deemed to be at minimal risk for integrity failure. This is represented by data points that are below the black dotted horizontal line, constituting 46.8% of wells in this category.

Wells that are above the black line and to the left of the yellow line, indicating that they have been shut-in for less than five years are also considered as having a low risk for integrity failure as there would have been some degree of monitoring on those wells in the past five years. Over a third (35%) of wells are in this low-risk category.

A medium level of risk for integrity failure is given to wells that are above the black line and between the yellow and red lines. These wells are older than 20 years and have been shut-in for between five and ten years and represent 6% of all shut-in wells.

Finally, wells that are above the black line and to the right of the red line are deemed to be the highest risk of integrity failure due to lack of monitoring, the equipment being beyond design life and potential well changes subsurface over time. Wells in this category, making up 12% of all shut-in wells, are older than 20 years and have been shut-in for over 10 years.

6.2.4 Well Depth

Well depth, and by association wellbore condition, is also a significant factor in assessing the complexity involved in abandoning a well. Generally, this results in a higher abandonment cost for deeper wells. In addition, there is a greater chance for there to be more zones exposed between the top of the cement and the intermediate/production casing depth for a deeper well. From a geological perspective, a deeper well crosses more formations, which in turn have variances in behavior, pressure and temperature systems thus adding in a complexity factor in terms of well design. Over 65% of total active wells currently are considered high risk because of their depth. As seen in the graph below, of all the active wells, 1098 wells are greater than 2000m in depth.

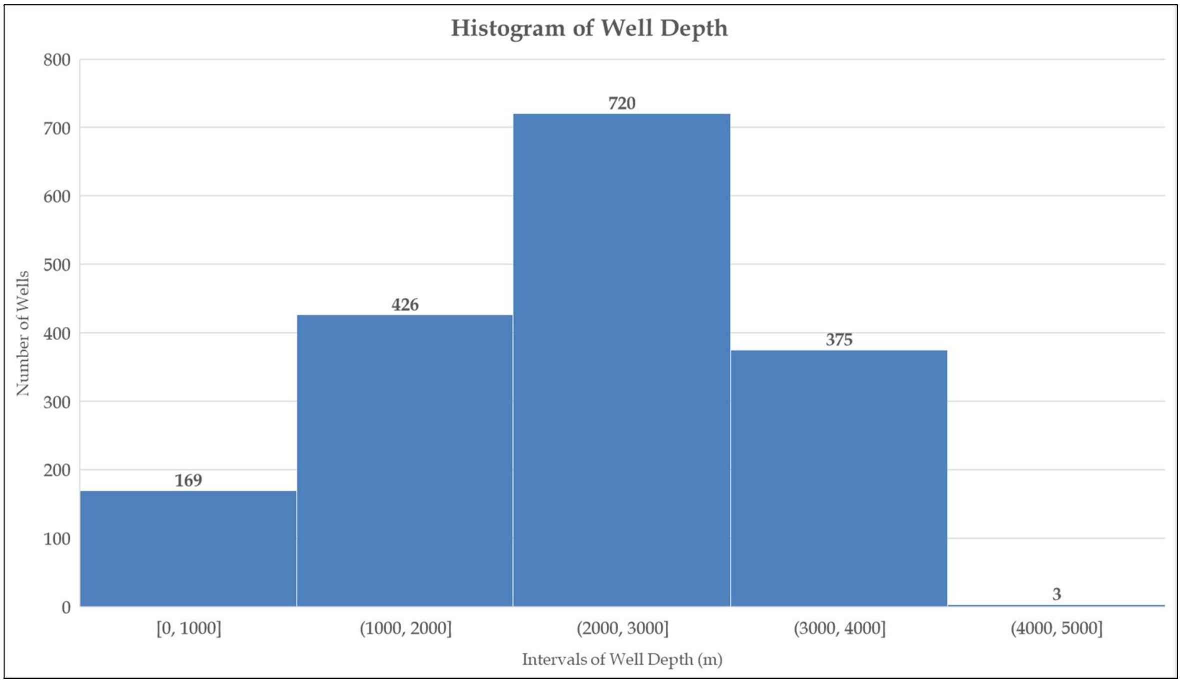

Figure 15: Well Depth Histogram

Categorizing the level of well integrity risk according to well depth is as follows:

- All wells that are less than 2500m in depth are at low risk – 64% of total wells
- All wells that are between 2500m and 3500m are medium risk – 31% of total wells
- All wells that are greater than 3500m are high risk – 1% of wells

6.2.5 Completion Status

There are seven primary completion statuses that add to abandonment complexity.

6.2.5.1 Single Completion

Once the decision has been made to either complete a well using an open hole completion, liner completion or perforated casing completion, a decision must be made on how many different intervals will be produced. The most common method is the single completion in which only one interval is produced at a time. A single completion is simple and results in fewer operating problems and less cost than multiple completions. Single completions are common on land where the reservoirs are either shallow or very deep. If the formation is very shallow, then drilling costs are minimal and single completions are usually best. In very deep wells, single completions are preferred because of the complexity and expense involved with a dual or triple completion in reservoirs deeper than 10,000 ft. (AAPG, 2020)

6.2.5.2 Single Completion Multiple Zone

A single wellbore can have tubulars and equipment that enable production from two segregated zones. In most cases, two tubing strings will be used to provide the necessary level of control and safety for the fluids from both zones. However, in some simple dual completions, the second or upper zone is produced up the tubing-casing annulus. (Schlumberger , 2020)

6.2.5.3 Monobore Completion

A monobore completion is a simple completion design that uses the same internal diameter from the bottom of the well to the surface. This may be accomplished by cementing a string of casing in a well, or by having tubing stabbed into a polished bore receptacle on a casing liner the same size as the tubing. (Al-Fadhli, 2018)

6.2.5.4 Dual Completion

A wellbore may have simultaneous production of hydrocarbons, water, or both from more than one producing zone. Although the term refers to cases in which only two separate zones are present, multiple zones may be involved. This completion technique avoids backflow from one reservoir zone to another in the wellbore.

(Schlumberger , 2020)

6.2.5.5 Suspended

Well suspension is the wellhead sealing for a particular period to save the wellbore during the drilling process or after the end of it. Well conservation is performed for a finite period for either strategic (supply control), market forces (commodity volatility) or other economic or safety purposes.

6.2.5.6 Plugged and Suspended (P&S)

Plugged and suspended is the intermediate state between well suspension and abandonment. This was a common practice in the 1980s and 1990s when wells became marginally economic to produce from yet were still seen as a possible risk. It included placing a surface plug and a bridge plug for safety; however, it did not go to the extent of performing zonal isolation which is a requirement of abandonment. Out of the entire dataset of 2436 wells, only seven wells had P&S completion status.

6.2.5.7 Coiled Tubing Deepened

Coiled tubing is used with downhole mud motors to turn the bit to deepen a wellbore. Coiled tubing drilling operations proceed quickly compared to using a jointed pipe drilling rig because connection time is eliminated during tripping. Coiled tubing drilling is economical in several applications, such as drilling slimmer wells, drilling in areas where a small rig footprint is essential, re-entering wells or where drilling is underbalanced (Schlumberger, 2019). In the entire database, there is only one instance in which the completion status is defined as Coiled Tubing Deepened; this is for a well that has a slim production casing of 4.5”.

There are varying degrees of complexity to execute an abandonment activity that is heavily dependent on the completion status of the well prior to the abandonment. Further, the different methods used in completion have varying degrees of susceptibility to well integrity issues over time. From a completion complexity perspective, the following low, medium and high-risk categories are identified:

- All wells that have a Single Completion are low risk from a completion complexity perspective – 30% of total wells
- All wells that have Single Completion Multiple Zones, Suspended or Plugged & Suspended completion status are medium risk from a completion complexity perspective – 31% of total wells
- All wells that have Monobore Completions or Dual Completions are high risk from a completion complexity perspective – 11% of wells

6.2.6 Zonal Exposure

As observed in the well database, across all 2436 wells drilled, there are 12 hydrocarbon carrying zones. A major requirement of abandoning a well in South Australia is that hydrocarbon carrying zones and aquifers must be isolated with no interzonal communication. When wells are constructed, there are multiple mechanisms such as cementing and casing that hold up the integrity of the well and act as infrastructure for isolation tools to be placed to stop zonal communication. However, upon analyzing the dataset, there were wells identified where the top of cement (data gathered from Cement Bond Log tests) was deeper than the production casing shoe. This means that there is an entire section of the well which, if there were hydrocarbon carrying zones in that section of depth, would represent monumental risk to the integrity of the well due to unpredictable formation pressure, temperature and flow conditions. In the Cooper-Eromanga basin, the worst-case scenario in terms of risk of integrity failure would be to have a well that has 12 zones exposed.

After using the data provided and formulaic variables created, Figures 30, 32 and 33 were compiled to visually identify and see trends of potential for zonal exposure. This was mapped against time to assess if drilling practices had improved over time to achieve zonal isolation objectives.

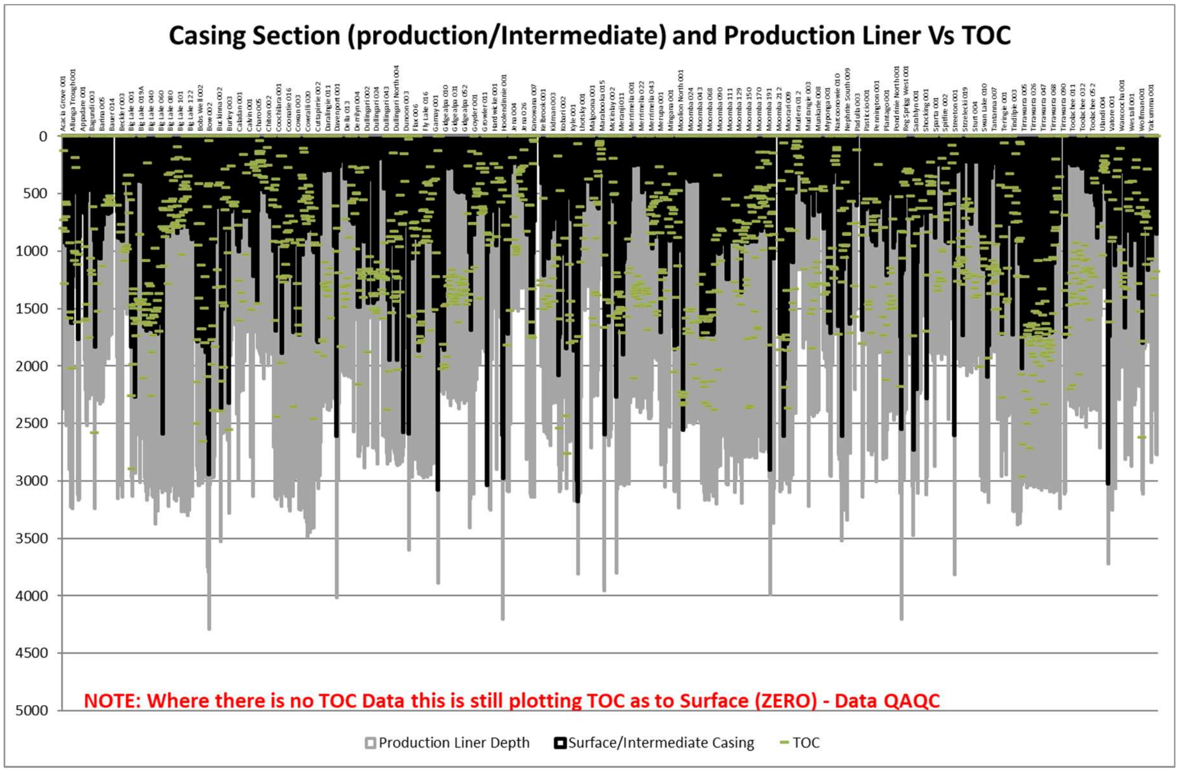

Figure 16: Casing Section and Production Liner vs TOC

In Figure 30 above, the horizontal axis represents the names of the different wells, while the vertical axis represents depth in meters. Grey lines denote production liner depth, overlaying black lines denote intermediate casing depth and the green dots showcase the top of cement. The wells that do not have TOC data still have associated data points at the surface.

Further data regarding zonal exposure relates to the numbers of zones, if any, the well is exposed to. Figure 31 below shows the numbers of wells exposed to between one and twelve zones.

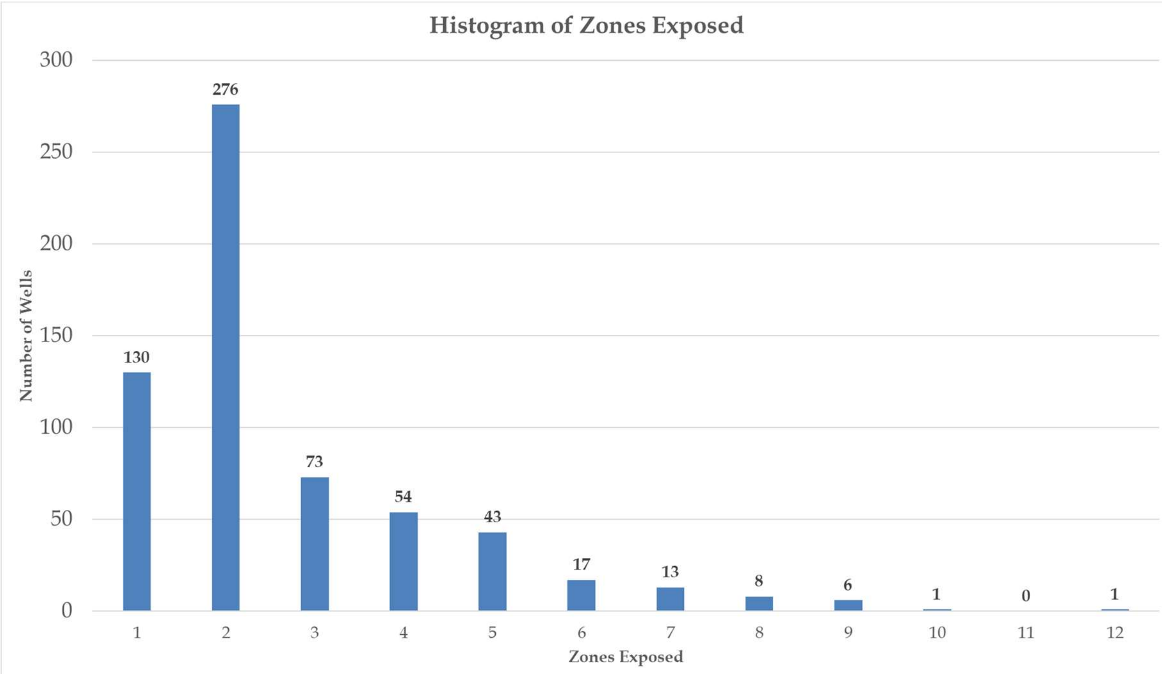

Figure 17: Histogram of Zonal Exposure

The above histogram denotes number of wells on the vertical axis and bins of zonal exposure on the X-axis. From the entire basin, there are 1146 wells that have no zonal exposure which leaves 1200 wells with zonal exposure. This implies that over 51% of total wells are exposed to integrity failure risk by virtue of zonal exposure that does not meet zonal isolation requirements.

Breaking this down further, 707 wells have at least one zone exposed, 493 wells have more than one zone exposed representing 21% of the total number of wells. This analysis shows the criticality of monitoring wells with multiple zones exposed. Currently, there are 89 wells with more than four zones exposed. These should be monitored first in terms of prioritization as they represent the biggest risk for zonal communication and integrity failure.

6.2.6.1 Evolution of Drilling Practice over time

Figure 32 and Figure 33 below show the standard practices for reducing zonal exposure in two periods: 1975 to 1990; and 1990 to 2017. The data covers all well types and all operators.

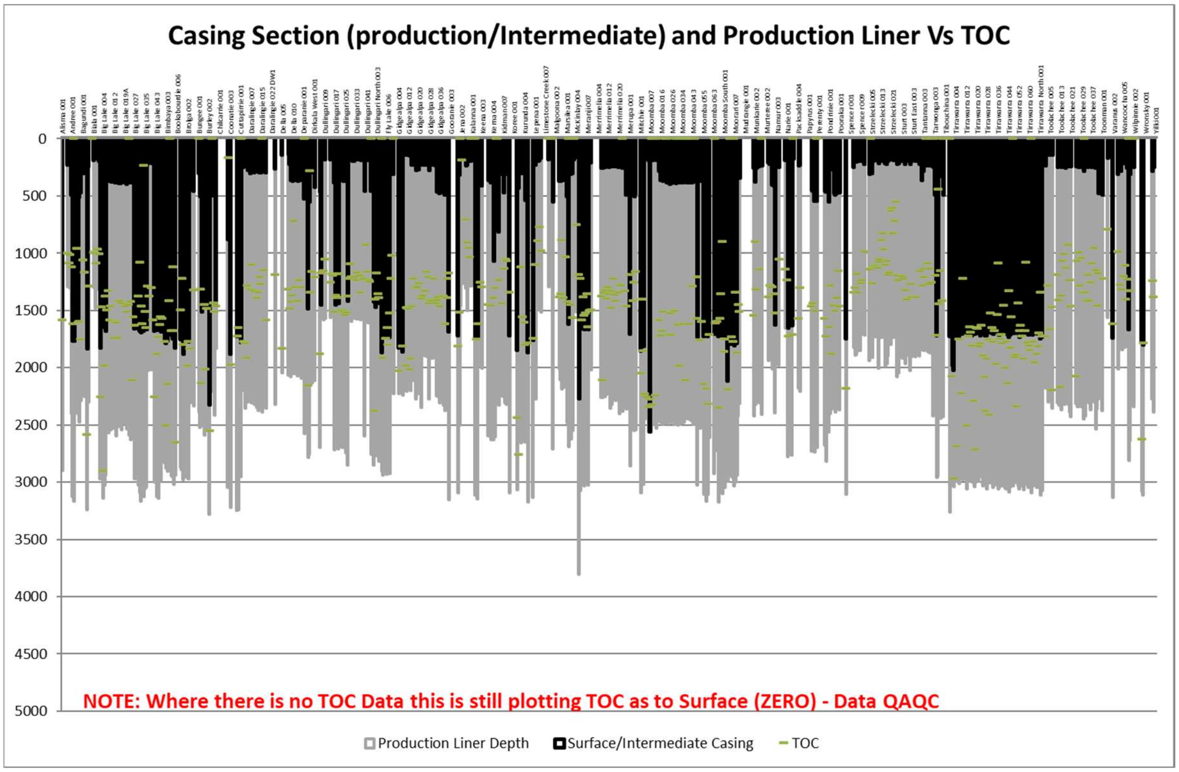

Figure 18: Production Liner vs TOC: 1975 - 1990

As observed in the figure above, drilling practices through the 1970s to the 1990s were inconsistent. The graph shows 462 instances, representing 54% of wells drilled at the time, where Top of Cement was deeper than the production casing, thus leaving significant potential for zonal exposure. Figure 33 below shows how this has changed in the subsequent period, 1990 to 2017.

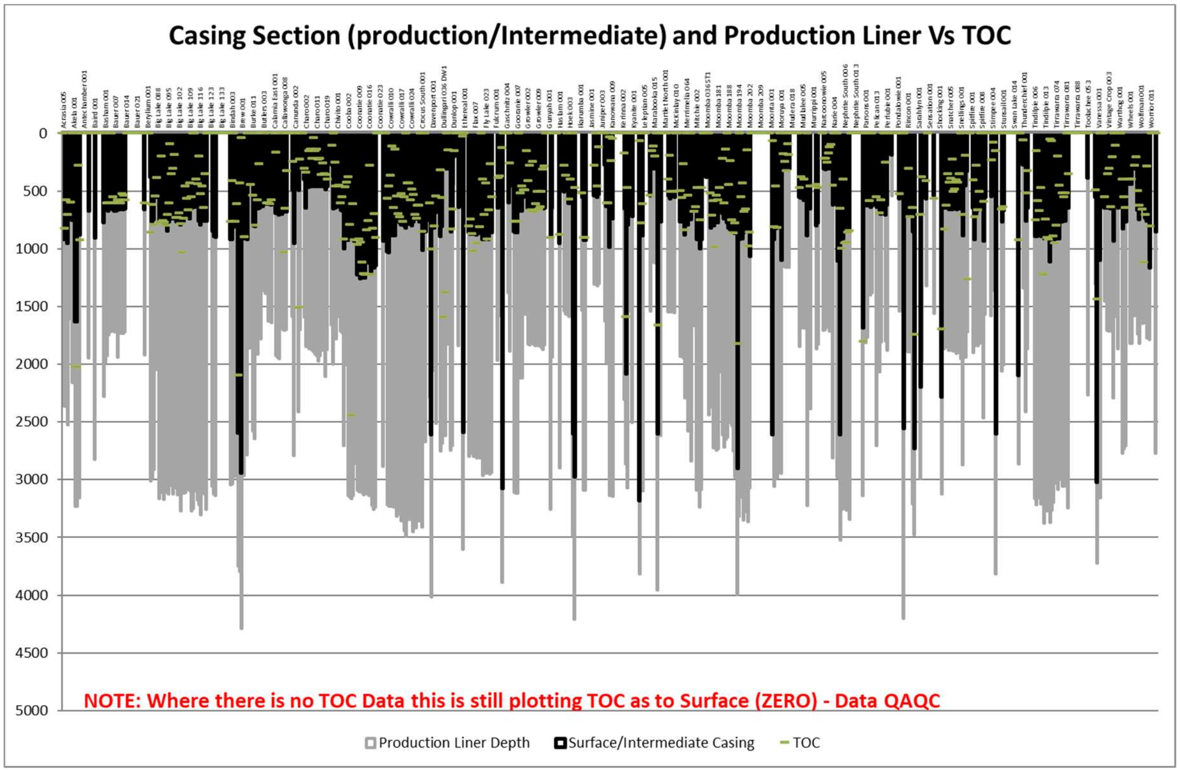

Figure 19: Production Liner vs TOC: 1990 - 2017

In stark contrast to the previous time frame, since 1990 there have just 208 instances or 13% of total wells drilled that have Top of Cement that is deeper than the production casing. Thus, there is far less potential for zonal exposure in wells drilled during this period compared to the prior time. This shows a clear improvement in drilling practices in the basin which further extends to the normalized (against depth) rate at which wells have been drilled.

Figure 34 below shows drilling performance vs time from 1961 to 2017. It can be seen that the rate of wells being drilled in meters drilled per day has increased, meaning target depths can be reached faster. Although less relevant to P&A aspects, this finding illustrates that wells are now being drilled almost twice as fast as during the period 1964 to 1995. Unless P&A rates match this increase, the increased drilling rates mean that an accelerating number of wells will require P&A for the same rig working the same period.

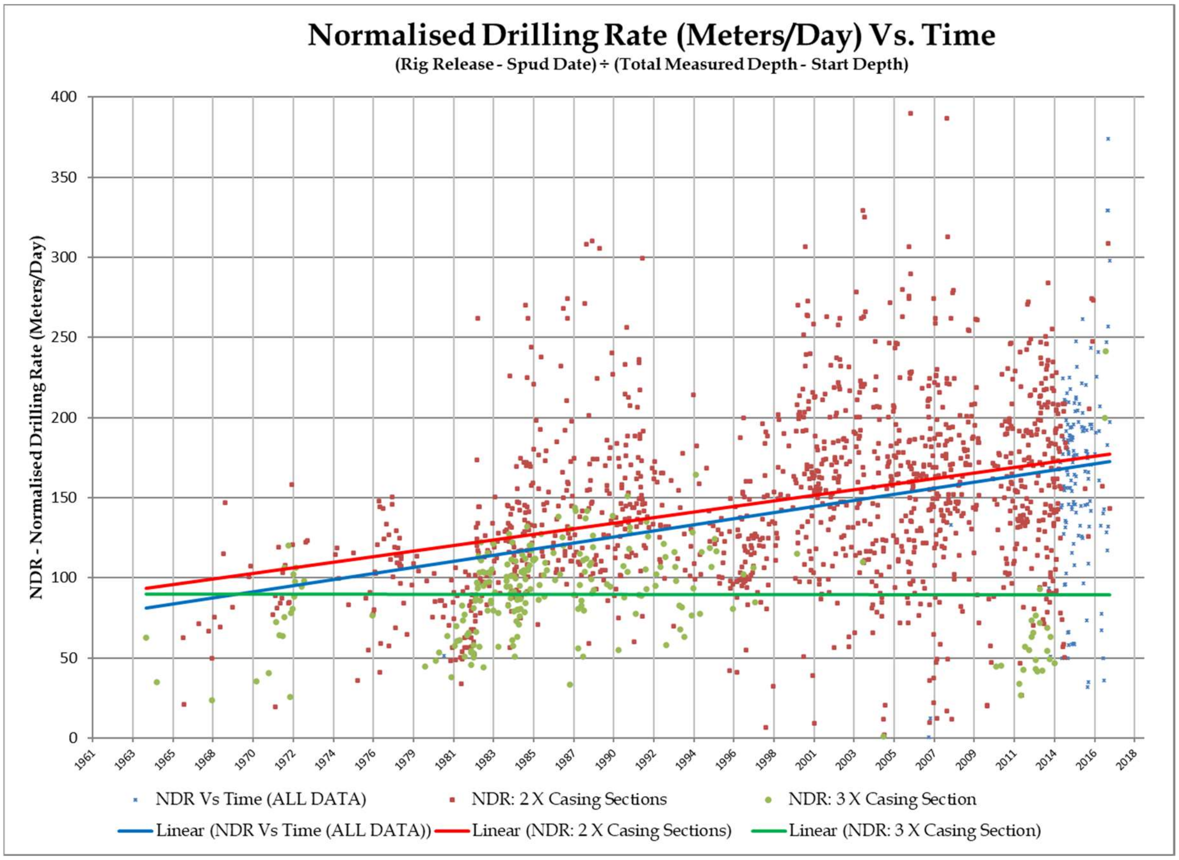

Figure 20: Drilling Performance vs Time

7. Unified Risk Code

The previous section highlighted six key features that potentially impact commercial, regulatory, and environmental risk that operators can be exposed to because of integrity failure. This is not an exhaustive list, and it can be modified, added to, or reduced from to have a more comprehensive risk code. Currently, there is no existing research or industry standard that identifies and amalgamates these key features into a single code to enable efficient prioritizing of wells based on associated risks. One of the key stated aims of this research was to create such a unified code. Based on the above analysis and identification of the six key factors related to the risk of well integrity failure, the following alpha-numeric unified risk code has been developed (the well stated below is for exemplification only):

For example:

Operator name: **Santos Limited**

Well name: Keleary 002

Unified Risk Code Key:

Well Age – Shut-in time – Well Depth – Production Geo – Completion Type – Zones Exposed

Unified Risk Code: 27-22-2534-7-SCMZ-2

Where the specific code indicates the following:

- Well Age – 27 years
- Shut-in time – 22 years
- Well Depth – 2534 m
- Production Casing OD – 7 inches
- Completion Status – SCMZ (Single Completion Multiple Zone)
- Zones Exposed – 2

Table 11 below is a summary of the risk categorization presented in the previous sections 6.2.1 to 6.2.6.

Table 9: Risk Legend

Risk	**Feature**					
	Well Age	**Shut-in time**	**Well Depth**	**Production Casing**	**Completion Status**	**Zones Exposed**
Base Case	0 to 10 years	1 to 10 years	0 to 2500m	5.5" +	SC	0 to 3
Medium	11 to 20 years	11 to 20 years	2501 to 3500m	4.5" to 5.5"	SCMZ, S, P&S	4 to 6
High	20 years +	20 years +	3500m +	0 to 4.5"	DC, MC	6+

If the existing risk code is deemed to be insufficient, as stated above, it can be added to or reduced based on prevailing demand.

8. Commercial Evaluation

Prior to calculating the total cost of execution of an abandonment program, it is critical to establish a base case for cost based on local basin experience. Once this is established, various multipliers can be added for the six features based on complexity that will undoubtedly increase the cost of execution of the abandonment.

At the time of writing, a total of 648 wells have been abandoned in the basin, a wide majority of which have been executed by Santos. Based on discussions with Abandonment Engineers at Santos and other operators, the following assumptions were made about the base case:

- Average daily service cost per well: **$ 22,000 AUD**
- Average time taken to abandon a well: **12 days** (This number varies based on complexity, however in this research there will be complexity multipliers added to the relevant features; hence this time will be assumed constant across all wells.)
- Base case cost per well: $ 22,000 x 12 days = **$ 264,000 AUD**
- Mobilization and other logistical, administrative, and regulatory costs are ignored for the purposes of this research.

In order to quantify the cost of abandonment of a well, the six features of the unified risk code are assigned multipliers based on low, medium, and high risk of each factor. Table 12 below shows these multipliers for each aspect of the unified risk code.

Table 10: Feature Cost Multipliers

	Feature					
	Well Age	**Shut-in time**	**Well Depth**	**Production Casing**	**Completion Status**	**Zones Exposed**
Base Case	0 to 10 years	1 to 10 years	0 to 2500m	5.5" +	SC	0
Multiplier	1x	1x	1x	1x	1x	1x
Medium Case	11 to 20 years	11 to 20 years	2501 to 3500m	4.5" to 5.5"	SCMZ, S, P&S	1 to 3
Multiplier	1.1x	1.1x	1.1x	1.1x	1.1x	1.1x
High Case	20 years +	20 years +	3500m +	0 to 4.5"	DC, MC	4 to 6
Multiplier	1.2x	1.2x	1.2x	1.2x	1.2x	1.2x
Misc. Coverage						6+
						1.3x

To show how the unified risk code and the multipliers would be used to evaluate the cost of abandonment, the example used in the previous section, 7 Unified Risk Code, is used.

Well code: 27 – 22 – 2534 – 7 – SCMZ - 2

Product of Multipliers: $1.2 \times 1.2 \times 1.1 \times 1 \times 1.1 \times 1.1 = 1.91664$

Total cost for this well = Base case x Product of Multipliers = 1.91664 x 264,000 = $505,992 AUD

Based on the above example, the cost of abandonment of all wells can be calculated. Figure 35 shows the distribution of existing wells across various abandonment total costs.

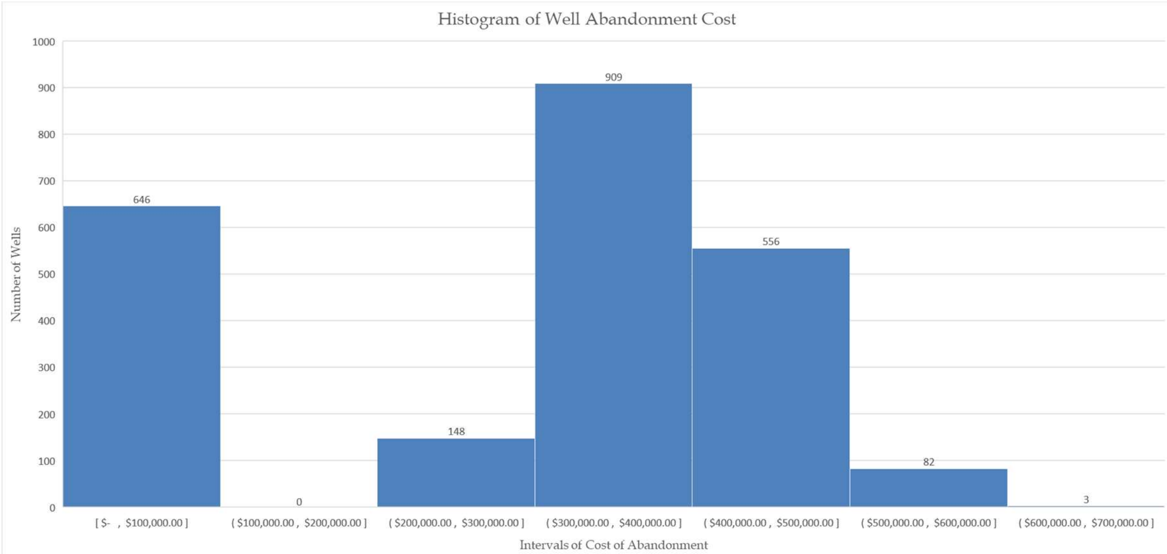

Figure 21: Histogram of Well Abandonment Cost

As can be seen, almost 70% of these wells will cost more than the base case. This indicates that most wells remaining in the basin are extremely high in complexity and require rigorous analysis and forward-thinking commercial and operational strategies to execute effective abandonment programs. **At current estimates, the total cost of abandonment of wells in the entire basin stands at a staggering $654 million.** This does not include the costs that have been mentioned in the assumptions, which would only increase this further. This analysis shows an urgent need for the industry, regulators, academia, and technologists to focus on this topic.

9. Well Abandonment Priority Targets

Based on the parameters discussed, associated risk codes and commercial costs of abandonment, there is a priority list of wells that need to analyzed first as they present a significant potential risk pertaining to well integrity failure relative to other wells. It is critical to note that some of the wells that were identified at a higher risk are currently producing wells. Given that these wells will continue producing until end of life, they are monitored on a consistent basis for well integrity and hence will be filtered out from this list. In Table 13 below the shut-in wells that represent the highest well integrity failure risk are shown, from highest to lower risk based on the six parameters covered in this research.

Table 11: Well Abandonment Priority Targets

Priority Order	Name	Risk Code	Total Cost
1	Plantago 001	25-16-2802.331-4.5-SCMZ-5	$ 607,191.55
2	Burke 001	48-23-2556.967-7-DC-5	$ 602,173.44
3	Tirrawarra 026	38-15-3005.328-5.5-SCMZ-5	$ 556,592.26

Priority Order	Name	Risk Code	Total Cost
4	Woolkina 001	38-14-3145.536-5.5-SCMZ-5	$ 556,592.26
5	Cuttapirrie 006	21-12-2956.56-3.5-MC-0	$ 551,992.32
6	Jack Lake 003	21-16-3098.597-3.5-MC-0	$ 551,992.32
7	Moomba 096	23-11-2549.042-3.5-MC-0	$ 551,992.32
8	Welcome Lake East 001	22-12-2884.932-3.5-MC-0	$ 551,992.32
9	Fly Lake 002	49-15-2948.94-7-DC-2	$ 505,992.96
10	Moomba 127	20-16-2838.907-3.5-MC-0	$ 505,992.96

From the above table , the following insights can be derived:

- On average, these wells are over 30 years old and have been shut-in for over 15 years.
- On average these wells are almost 2900m deep, which seems to be the average depth across the basin, thus showing a weaker correlation to risk of integrity failure.
- Except for Burke 001 and Fly Lake 002, the smaller sized production casing equipment represents a higher risk due to increased complexity of managing a smaller production hole.
- From an operator perspective, most of these wells belong to the same operator and hence show their potential exposure commercially and environmentally.
- From a hydrocarbon perspective, eight of these ten wells are gas wells
- Although Monobore Completions are more economically viable compared to other completion methods, the single tubular structure from the surface to the reservoir compromises on integrity with increasing depth and deviation as it does not account for the varying conditions. The table shows that 50% of the priority list of higher risk are Monobore Completions.

10. Scalable, Economically Viable Forward-looking Abandonment Strategies

As seen above, the cost of executing a traditional abandonment strategy across the basin for all the wells that are yet to be abandoned is staggering. To alleviate this extreme financial burden on all operators that either own, co-own, operate or hold non-operational interest in wells in the basin, emerging technology can be used. The prioritization of the wells to be addressed first can be done via the Unified Risk Code discussed in section 7. Based on executing a worldwide preliminary market research for unique technologies pertinent to Abandonment, the following emerging technologies were identified as being potentially helpful in executing a forward-looking abandonment strategy.

10.1 Winterhawk Well Abandonment

Winterhawk Well Abandonment Ltd. has developed new technology for the economical and environmentally responsible asset retirement (abandonment) of oil and natural gas wells. Winterhawk's tools can be used to replace the standard bridge-plug-and-cement process to perform first-time abandonments, or to repair previously abandoned wells that have developed leaks of greenhouse gases (GHG). Winterhawk has also developed a means to locate leak sources in previously abandoned wells without the need for expensive and intrusive logging.

- PMAT – Polymer Modified Asphalt Tool

The Polymer-Modified Asphalt Tool (PMAT) is designed to plug and seal wells that have reached the end of their productive lives. It may be used for first-time abandonments, or to seal previously abandoned wells that have developed micro-annular leaks.

- Mechanical Diagnostic Tool

The Mechanical Diagnostic Tool (MDT) is a device to determine the location of a micro-annular gas leak from a previously abandoned well without the need for expensive and intrusive logging.

- Casing Expansion Tool

The Casing Expansion Tool (CET) is identical to the Mechanical Diagnostic Tool but has a different application. When used as a surface casing vent flow (SCVF) remediation technology, the CET expands the casing until the steel plastically deforms. This permanently shuts off the leak paths in the cement sheath.

10.2 Pluto Ground Technologies

Pluto Ground Technologies have developed a smart slurry named SmartSet®, a solution enabling better zonal isolation than traditional methods. It is a formulation of nontoxic, inorganic powders that when mixed with water provide a controlled right angle set with rapid compressive strength generation in downhole conditions. Time from mixing the slurry to the right-angle set can be engineered within minutes as desired with zero gel strength generation between the fluid and set states.

SmartSet® slurries are engineered for each application based on job placement time and temperature at depth. The slurry will be a combination of either SmartSet® LT, MT, or HT (low, medium, or high-temperature products) together with C-Set, M-Set Ultra, and I-Set (inhibitor) if required. Other operational characteristics include:

- Zero gel strength generation – thin fluid until reaches set point providing very low friction pressures in coiled tubing applications, tubing or drill pipe including most BHA components including the BIT (viscosity can be increased through additives).
- Right angle set – thin fluid to immovable solid within 120 seconds at set point always - key to stopping gas influx (time to set point can be delayed with I-Set) eliminates channeling.

- Withstands 30% contamination (organic or inorganic) with no effect on set time characteristics.
- Rapid compressive strength development - average compressive strength is 4,000 psi.
- Unaffected by hydrostatic pressure – set is only affected by time and temperature.
- Near wellbore phenomenon – within its normal temperature range (35 °C - 135 °C) it sets up faster in the wellbore periphery than in the actual wellbore, unless a squeeze is required. For colder applications an accelerator may be required.
- Easy to drill with no cuttings – approximately 10 m/hr using water, coiled tubing, and motor.
- Easy to clean up on job – can be diluted with water.
- Environmentally friendly – all materials are completely non-toxic (OCNS category D/E).
- Will not allow filter cake deposition.

10.3 Welted Technologies

Welltec's WAB range, when incorporated within the cased hole for IS0 14310 V0 barrier or open hole, for IS0 14310 V3 isolation across the cap rock during well construction phase, will provide added future value as the foundation for placement of P&A cement plug, significantly reducing the future complexity and cost associated with P&A.

10.4 Inflatable Packers International (IPI)

IPI is an Australian company based in Perth that has gained traction globally for their Plug and Abandonment Solutions such as the ones outlined below:

- Permanent Inflatable Bridge Plug (PIBP)

IPI's Permanent Inflatable Bridge Plug (PIBP) incorporates the DuraGRIP™ bidirectional sealing inflation element as an integral part of a modular system that enables adaptability to a wide range of configurations and tool sizes.

- Remedial Cementing Packer (RCP)

IPI's retrievable Remedial Cementing Packer (RCP) is a field proven innovative inflatable packer system designed for retrievability after remedial cementing. The retrievable RCP features drillable residual components, which makes it the optimal solution for shutting-off lost-circulation zones encountered during drilling operations.

- Retrievable Inflatable Bridge Plug (RIBP)

IPI's Retrievable Inflatable Bridge Plug (RIBP), utilizes its field proven PIBP and ICP inflation valving system in conjunction with a DuraGRIP™ packer element, which provides bidirectional sealing and anchoring. There are two standard mechanisms to enable deployment using drill pipe, coiled tubing, and capillary tube.

- Large Diameter Plug & Abandonment Packers

Specifically designed for the plugging of wells as part of usual cementing procedures prior to abandonment. These permanent inflatable bridge plugs have relatively small run-in diameter, large setting range and easy installation.

- Thru-Tubing Retrievable Inflatable Bridge Plug (TT-RIBP)

IPI's Thru-Tubing Retrievable Inflatable Bridge Plug (TT-RIBP) utilizes InflataLOK™ valving system in conjunction with a DuraGRIP™ packer element, which provides bi-directional sealing and anchoring. The TT-RIBP is an innovative design with an equalization mechanism allowing the operator to equalize any potential pressure below the packer with the annulus above, before activating the deflation mechanism.

- Thru-Tubing Permanent Inflatable Bridge Plug (TT-PIBP)

IPI's Permanent Inflatable Bridge Plug (PIBP) incorporates the DuraGRIP™ packer element which has bidirectional sealing and anchoring capability. The design also utilizes an equalization feature, that eliminates the effect of wellbore pressure, to ensure correct tool function regardless of setting conditions. There are three standard configurations to enable deployment on coiled tubing, capillary tube, and *wireline/slickline.

10.5 Tendeka

Tendeka offers a range of zonal isolation swellable and mechanical packer technologies designed to prevent fluid communication between individual zones.

- Tendeka's SwellRight Swellable Packers are a permanent packer solution suitable for many applications where a pressure seal or zonal isolation is required. SwellRight packers help reduce well construction costs, extend well life, and improve well integrity. These permanent packers provide the long-term stability and reliability required to isolate producing zones.
- Tendeka's Retrievable SwellRight Packer option has been designed to isolate the wellbore while enabling the easy removal of the entire assembly from the wellbore without any milling operations.
- Tendeka also offers SwellRight Ultra Packer, a cost-effective solution for high pressure applications, providing the highest-pressure rating on the swellable market. Enabling the customer to utilize smaller pup joints, Tendeka's Ultra Packers can effectively reduce the amount of rubber element required for high pressure applications, for use in horizontal and vertical wells.

10.6 Interwell

Since 2021, Interwell has been working on a groundbreaking approach to permanent well abandonment of oil and gas wells. The goal of the project is to create formation-to-formation barriers across multiple strings of pipe using wireline as the deployment method. This technology has the potential to be an alternative to today's expensive and time-consuming practice of cement plugs.

- Interwell P&A has run trials in 18 different wells since 2016.
    i. Canada Land: 15
    ii. Italy Land: 1
    iii. UK Land: 1
    iv. UK offshore: 1
- The most recent trial campaign was in Canada, with three different operators and nine wells. The focus was Surface Casing Vent Flow / Sustained Casing Pressure fix, as an alternative to today's methods.

11. Conclusions

At the completion of this research, the following conclusions could be drawn:

- In the South Australian portion of the Cooper-Eromanga basin, the portfolio of wells that are shut-in or suspended has been growing over the past 60 years. This is due to the rate of Abandonment not matching the rate of Drilling in the basin. As a result, operators in the basin face increasing environmental, regulatory, and operational risk due to potential well integrity failure over time.
- The average age of the wells in the basin is 23 years and for wells that have been shut-in, the average shut-in time is 11 years. Given that design life of downhole equipment can range between 10 – 20 years (reference), it has become paramount to develop and plan a forward-looking Abandonment strategy to address risks associated with these wells.
- From a regulatory perspective, the Department of the Premier and Cabinet have reported that 582 wells were non-compliant due to lack of zonal isolation under the current regulatory framework. However, upon completion of this research, it was discovered that in fact 622 wells are non-compliant, corresponding to 25.5% of wells being non-compliant.
- From a Wellbore geometry perspective, the hole and casing size of the wells has changed over the past 60 years of operations in the basin. Since around 1995, the wellbore and casing size has decreased from the previously standard 8.5" hole and 7" production casing to smaller options.
- To measure the efficacy of drilling, drilling rate was used. This metric is the ratio of depth drilled to total time taken to drill. Based on normalized drilling rate over time, drilling performance has improved dramatically by a staggering 50% in the Cooper-Eromanga basin. This is likely owing to multiple factors such as advancing drilling technologies and better understanding of the basin.
- Zonal isolation is a critical risk as it pertains to well integrity. Observing drilling practices over time, it is quite apparent that a larger proportion of older wells have the top of cement deeper than the production casing shoe compared to newer wells. This implies zonal exposure has reduced over time, owing to better drilling practices and better risk management strategies being in place.

- There are multiple factors that have been considered as contributors to well integrity. In this research, the following six parameters were identified to be critical. Factors can also be added, removed, or modified to make this is a comprehensive and scalable assessment:
    - Well Age (Yrs.)
    - Shut-in time (Yrs.)
    - Drilling and Production Geometry (Hole and Casing OD)
    - Well Depth (m)
    - Completion Status
    - Zonal exposure
- These six critical parameters were used to define a unique alphanumeric risk code for each well that would help provide context on risk associated with a particular well and contributing parameters. For further details see section 7.
- To calculate the cost of abandonment for all the wells in the basin, a base case was defined based on input from various engineers in the field. This base case cost accounted for 12 days taken to abandon a particular well and $ 22,000 AUD for services resulting into a total of $ 264,000 per well. This did not include mobilization and administrative costs. To account for complexities added in due to the six key parameters that would make a well vary from the base case, various cost multipliers were factored in. Following this, the total cost of Abandonment for the entire basin was calculated to be **$654 Million AUD**.
- After performing extensive quantitative analysis amalgamating various impactful parameters on well integrity, a priority list of wells was generated from the model built. Unsurprisingly, 80% of wells in the list are gas wells.
- As a part of the forward-looking abandonment strategy proposed, the magnitude of the abandonment task and associated costs are staggering. To effectively and economically execute this, emerging technologies are seen as potential creative solutions

12. Appendix 1

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