IADC GEOTHERMAL WELL CLASSIFICATION

Prepared under the auspices of the IADC Geothermal Committee

Issue 1.0 – February 17, 2025

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ISBN: 978-0-9996235-7-2

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Document Review History		
Issue	**Review Status**	**Date**
1.0	First draft issue	

Contents

Foreword

The IADC Geothermal Well Classification is the initial body of work that will be published by the IADC Geothermal Committee. It will serve as a standalone document as well as form the initial section of the IADC Geothermal Well Drilling Guidelines that will be published in 2026, as a dedicated chapter of the IADC Drilling Manual.

Acknowledgments

IADC would like to thank the following individuals and their respective organizations for their support and contribution to the development of this classification:

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The classification work group would also like to thank the wider IADC Geothermal Committee for its support and endorsement of the classification:

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Blade Energy
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Eavor
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Ensign Energy
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Halliburton
Helmerich & Payne
HP Well Screen
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Inco-Drilling
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MND
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RED Drilling
Rystad Energy
Shell
Thermaprime Drilling Corp.
Valaris
Vercana
Weatherford
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NOTE: The list of companies above reflects the company membership of the IADC Geothermal Committee at the time of publishing. For an up to date list of member companies, please refer to the committee page on the IADC website (https://iadc.org/committees/geothermal/)

Further Support

The following geothermal industry associations have supported this classification system:

- **IGA (International Geothermal Association)** serves as a global umbrella organization that facilitates collaboration, research, and policy development across the geothermal sector.

- **EGEC (European Geothermal Energy Council)** focuses on advocating for geothermal energy policies, market development, and industry growth within Europe.

- **Geothermal Rising** is a U.S.-based organization committed to public outreach, education, and fostering industry connections to support geothermal energy expansion.

Introduction to the IADC Geothermal Well Classifications

Welcome

Welcome to the International Association of Drilling Contractors (IADC) Geothermal Well Classification. This Classification was developed by IADC members to accomplish the following:

- Establish a foundational framework for the IADC Geothermal Well Drilling Guidelines, providing clear context to distinguish well types and define the necessary equipment, standards, processes, and training for their safe and efficient construction and operation.
- Act as a communication tool to bridge the gap between drilling and non-drilling professionals, using terminology familiar to the broader drilling industry to facilitate informed discussions.
- Present the complexities and unique challenges of geothermal well drilling in a clear and accessible manner, avoiding excessive technical detail while emphasizing project-specific drilling risks for comparison.
- Identify gaps in the supply chain that may hinder geothermal project development, enabling IADC members to address these challenges and develop geothermal-specific solutions.

Provide an international classification system for geothermal well construction that reflects the practicalities of "putting a hole in the ground", the risks associated with drilling operations, and the long-term operation of the well.

Background

The geothermal sector encompasses a broad and often inconsistent range of terminology, definitions, and acronyms that can blend shallow, non-drilling ground source heat pumps with deeper geothermal applications. The rapid emergence of new concepts further compounds this inconsistency, with some adapted from earlier approaches and others newly developed or in the prototype stage. As a result, professionals outside the sector frequently struggle to navigate and differentiate between these evolving technologies.

Even major organizations, such as the International Energy Agency (IEA), continue to refine their language to accurately describe various geothermal concepts, including (but not limited to):

- Hydrothermal.
- Low Enthalpy.
- High Enthalpy.
- Enhanced Geothermal Systems (EGS).
- Advanced Geothermal Systems (AGS).
- Hot Dry Rock (HDR).

- Hot Sedimentary Aquifers (HSA).
- Closed Loop Geothermal Systems (CLGS)
- Advanced Closed Loop (ACL).
- Underground Thermal Energy Storage (UTES).

The challenge lies in ensuring clarity and consistency as the sector evolves.

Additionally, classifications such as "conventional" and "unconventional" are not particularly useful, due to their transient nature. An example is the shale gas revolution in the United States, initially categorized as an "unconventional" resource, shale gas has since become the dominant and most prolific source of natural gas production in the country. In this situation, it is worth considering whether it could still be considered unconventional.

Similarly, the IEA's "Next-Generation Geothermal" terminology [IEA, 2024] suggests a shift away from more "conventional" geothermal systems toward newer concepts and technologies. However, what happens when these so-called "next-generation" approaches become mainstream while conventional systems continue to expand? If these technologies scale as successfully as shale gas did, then the distinction between conventional and next-generation will eventually lose relevance.

Rather than relying on these shifting definitions, the industry would benefit from a more structured and descriptive classification system. This classification aims to provide clarity by focusing specifically on the drilling and operation of geothermal wells, avoiding unnecessary complexity and contributing to a more consistent understanding within the sector.

Application and Status

The IADC Geothermal Well Classification is intended for "deep" geothermal wells. As there are a variety of definitions of "deep" in the industry and different countries, our notion of "deep" is intended for wells generally deeper than 200–300 m that require multiple hole sections or casing sizes to reach the intended target.

While efforts have been made to create a comprehensive classification, it is expected to accurately cover approximately 80% of geothermal concepts. Notable exceptions include offshore geothermal projects, which remain in the feasibility stage, and the repurposing of existing wells for geothermal use. The latter represents a significant outlier, potentially warranting a separate classification, as the challenges of re-entering and working over existing wells differ fundamentally from drilling new ones.

This classification will also serve as the foundation for a complexity calculator, designed to provide a clear and accessible visual representation of the complexities and unique challenges associated with geothermal wells. While the calculator is still in development, it is expected to be released following the publication of this document.

In addition to the calculator, worked examples are provided to illustrate the practical application of the classification system, demonstrating how it can be used to assess and compare different geothermal well projects.

Structure and Contents

The classification has been developed in three parts.

- Part 1: Classification Definitions
- Part 2: Complexity Calculator and Technical Appendix (under development)
- Part 3: Worked Examples to show the practical application of the classification system (under development)

Classification Definition

The IADC Geothermal Well Classification is split into three levels, with a total of eight categories:

- Project: provides the overall context for the well's purpose, including:
  - Reservoir Dependency.
  - Asset Purpose.
- Site: focuses on operational and environmental constraints related to the location of the project, including:
  - Location Sensitivity.
  - Rig Capacity.
- Well: defines the technical and engineering complexities related to constructing and operating the well, including:
  - Design.
  - Construction.
  - Drilling Complexity.
  - Well Control.

Each category includes the main classification(s), binary flags that indicate the presence or absence of specific challenges, and specific attributes, which are typically represented as integer values (e.g., maximum temperature).

IADC Geothermal Well Classification Visual Color Key		
Category	**Color**	**Description**
Classification		The main classification is generally a single selection, except for Asset Purpose. Monotone shades, ranging from white to dark grey, indicate increasing levels of complexity; darker shades generally represent greater complexity, except for project-level categories, which are not subject to this scale.
Binary Flags		Binary flags indicate specific challenges that increase the well's complexity or require special attention. These flags can either be selected or not.
Specific Attributes		Specific attributes are key parameters chosen from a predefined list or provided as integer values to help determine equipment requirements and operational complexity.

The classification is illustrated in Figure 1 and each category is defined in the following sections.

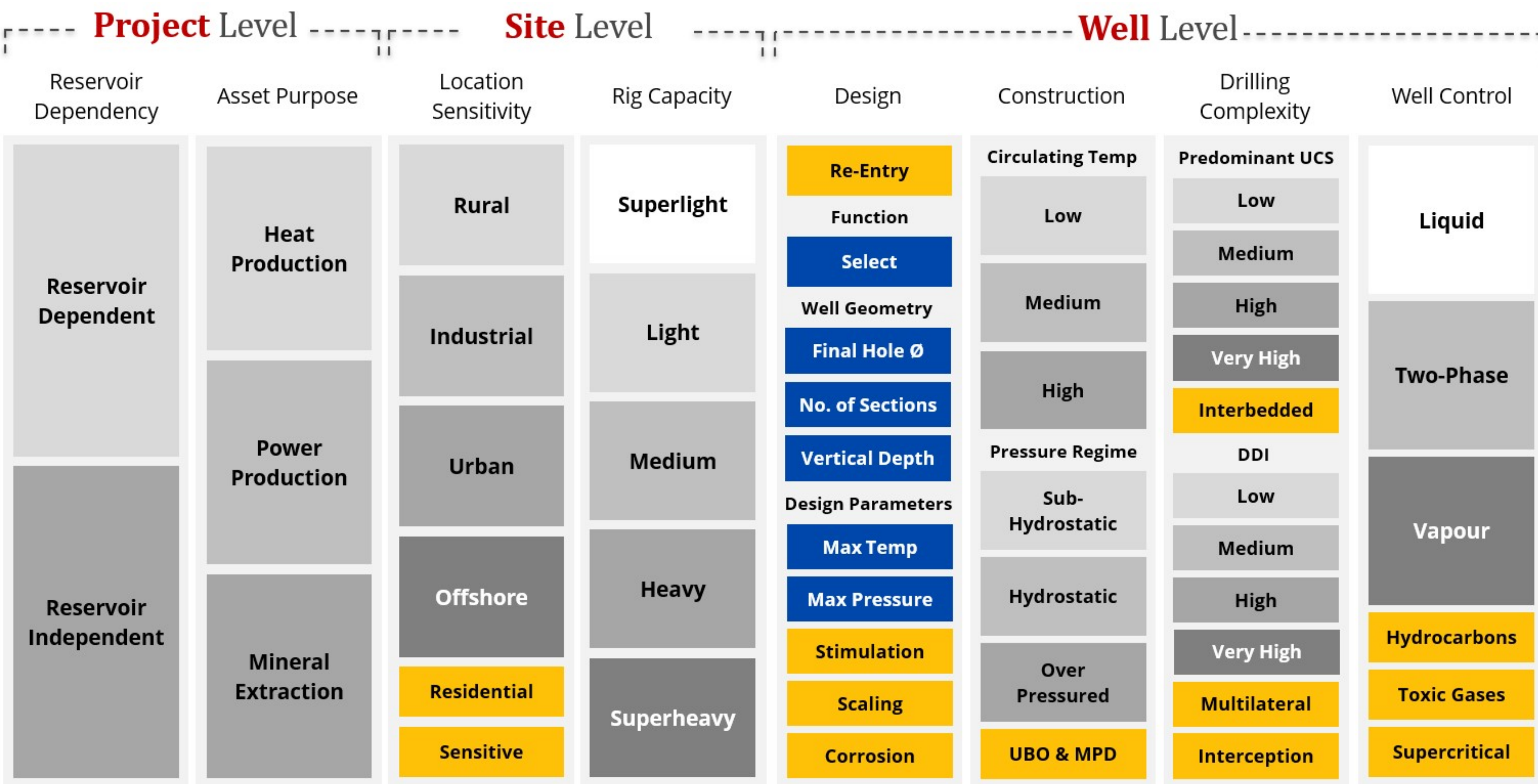

Figure 1: IADC Geothermal Well Classification Visual

1.0 Reservoir Dependency

Geothermal resources and technologies can be classified in various ways, with frameworks evolving as the sector expands and new technologies emerge. This category distinguishes geothermal resources based on their dependence on a natural reservoir, characterized by the presence of heat, permeability and fluid, without considering other attributes such as temperature, enthalpy, or extraction methods.

Historically, the reliance on a natural reservoir has been the primary distinction between what has been referred to as conventional and unconventional geothermal resources [Khodayar & Björnsson, 2024]. Most recently the International Energy Association released a report that made a distinction between conventional and next-generation geothermal projects [IEA, 2024]. The transient nature of these definitions does not lend itself to a classification system, just as unconventional (e.g., shale gas) wells have become the norm in areas like the United States. Instead, emphasizing the physical differences between resources is sufficient to highlight the varying geological risks associated with different project types.

The Reservoir Dependency category is defined in Table 1.

Table 1: Reservoir Dependency

Classification	Definition
Reservoir-Dependent	The geothermal resource possesses the necessary conditions of heat, permeability and fluid.
Reservoir-Independent	The geothermal resource has sufficient heat but lacks permeability and/or fluid.

2.0 Asset Purpose

The value of a geothermal project is derived from the produced fluid. The produced fluid has a wide range of uses (refer to Figure 2) but can be broadly categorized into three primary functions:

- Producing heat.
- Generating power.
- Extracting valuable minerals.

Arguably, the extraction of minerals from a geothermal fluid can be classified as a secondary function. However, there are an increasing number of projects where the main economic driver is the extraction of minerals. Therefore, this has been included as one of the primary functions.

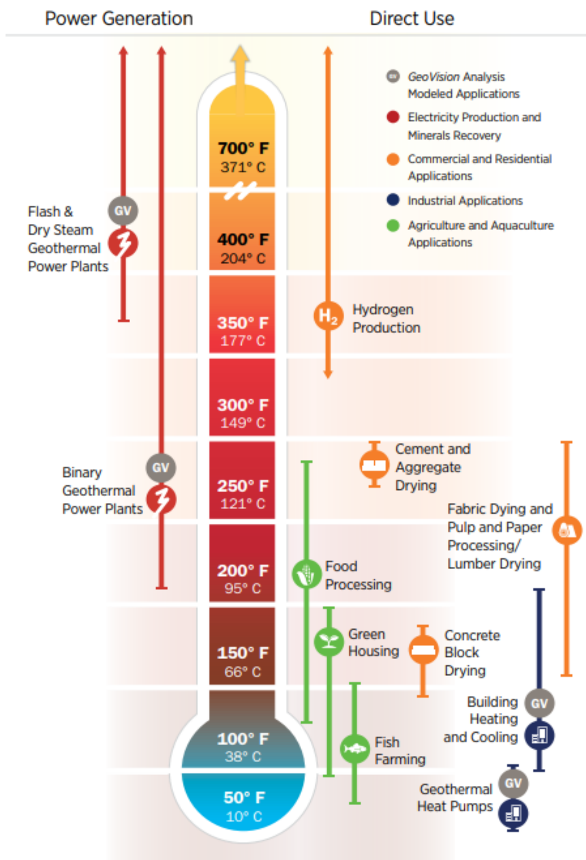

Figure 2: The Continuum of Geothermal Energy Technology Application and Uses (U.S. Department of Energy, 2019)

The project's overall value can come from a cascade of purposes, especially for projects where lower-temperature fluids are extracted. For example, the hot fluid produced from a well can produce power using a binary (e.g., Organic Rankine Cycle) plant with the lower temperature output of the plant being fed into a district heating network, before being reinjected. Therefore, the Asset Purpose selection can be singular or multiple. Refer to Table 2.

Table 2: Asset Purpose

Classification	Definition
Heat Production	Hot fluid is directly used to provide heat for district heating systems, greenhouses and aquaculture, and various industrial processes.
Power Production	Hot fluid or vapor is used to generate power in power plants, which range from binary systems for low-enthalpy resources to dry steam systems for high-enthalpy resources.
Mineral Extraction	Minerals such as lithium, silica, and various metals can be extracted from the hot fluid.

3.0 Location Sensitivity

The location of a geothermal project is often guided by its intended purpose (i.e., asset). Projects delivering heat directly to end-users are typically located nearby to reduce inefficiencies in long-distance heat transport. Drilling operations may be subject to additional considerations and restrictions based on the sensitivity of the location. Rural areas generally present fewer constraints related to noise, light pollution, and the footprint of the operational site. In contrast, urban environments tend to impose more stringent regulations and restrictions on drilling activities, logistical operations, site access, and footprint due to the heightened sensitivity of these settings.

The location of a geothermal project can be classified as rural, industrial, urban, or offshore. The first three categories generally correspond to increasing levels of restrictions or regulations, with rural locations facing the fewest and urban environments the most. While there are currently no operational offshore geothermal projects [Batir et al., 2024], feasibility studies have explored the potential for repurposing oil and gas wells for geothermal use (see design category). As a result, the offshore classification has been included to reflect its future potential. Refer to Table 3.

Table 3: Location Sensitivity

Classification	Definition
Rural	An area with low population density and minimal development, often characterized by open landscapes, agricultural activities, or desert regions
Industrial	An area designated for industrial activities, which may include manufacturing facilities, warehouses, and heavy industrial infrastructure
Urban	A densely populated area with significant residential, commercial, and infrastructural development
Offshore	A marine environment using fixed surface installations, such as manned production facilities or wellhead platforms

In some cases, additional flags may be required to capture specific sensitivities or constraints associated with a location. These flags provide further granularity to the classification system by highlighting challenges that may influence operations; two examples of these flags are the Residential Flag and the Sensitive Flag (refer to Table 4). The Residential Flag applies to rural or industrial locations only, where the proximity of residential properties imposes additional constraints. The Sensitive Flag serves as a broader marker for complex scenarios, including heightened environmental concerns, limited public acceptance, potential activism, or resource scarcity (e.g., water limitations in desert areas).

Table 4: Location Sensitivity – Flags

Flag	Definition
Residential	Indicates the presence of nearby residential properties, leading to additional constraints related to noise, light pollution, and community considerations
Sensitive	Represents heightened complexity due to environmental concerns, poor public acceptance or activism, or scarcity of critical resources (e.g., water in desert regions)

4.0 Rig Capacity

The design of a geothermal well determines the required rig capacity, encompassing key parameters such as hook load, hoisting and pumping capacity, and the torque output of the driving system. Onshore drilling rigs are commonly categorized by their hook load capacity, power rating, and depth range. While these categorizations are intrinsically linked, the hook load capacity is the most relevant criterion for defining the rig requirements when classifying a geothermal well.

The rig's maximum hook load must be sufficient to safely handle the heaviest casing string. This hook load is determined by the size, linear weight and length of casing as well as the trajectory, fluid density and running method.

NOTE: Casing strings can be floated for long sections to take advantage of buoyancy forces.

This calculation can be performed to estimate the hook load capacity, considering the heaviest casing string with the following formula:

$$Hook\ load = L\omega B_f + Block\ Weight$$

In this formula, L = total length of casing, ω = linear weight of casing, and Bf = buoyancy factor. The buoyancy factor is calculated by the density difference between the casing being run and the density of fluid, which can be assumed to be 0.87 for a steel casing run in water. The block weight considers the weight of the hook and top drive and can be assumed to be 22 mT (50 klbs). This calculation assumes that the well is vertical. Additionally, for deviated wells, the impact of additional drag must be considered. In general, the higher the Drilling Difficulty Index (refer to Section 7.0 Drilling Complexity) the more complicated it can be to determine the maximum hook load, frequently requiring torque and drag simulations to be performed.

The classification of rig capacity as per the required hook load range has been aligned with the RystadEnergy Land Rig Market Analysis [RystadEnergy, 2024], with the addition of the Super Light classification for rigs with a hook load capacity under 100 mT (221 klbs). This alignment should allow users to draw comparisons with the classification of their geothermal well and the availability of suitable rigs in the project region. Refer to Table 5.

Table 5: Rig Capacity

Classification	Hook Load Range	
	Metric Units	Imperial Units
Super Light	<100 mT	<221 klbs
Light	100–199 mT	221–440 klbs
Medium	200–399 mT	441–881 klbs
Heavy	400–599 mT	882–1,322 klbs
Super Heavy	>600 mT	>1,323 klbs

5.0 Design

The design of a well is critical to confirm it can fulfill its purpose of being the conduit for the working fluid(s) of a geothermal system between the heat resource and the surface. Many key attributes impact the design and the overall complexity of the project. Therefore, this category is the most complicated and cannot be simplified without the loss of fundamental detail.

There are geothermal systems that are designed to use existing wells, working over existing wells to effectively turn them into closed-loop heat exchangers. As these wells have already been designed for their prior use, this category becomes limited in its use to define the complexity of the operation. Each re-entered well comes with unique challenges that cannot be well captured in a classification system, as proposed (refer to Table 6). As a result, a logic switch is provided to identify these wells in the classification system.

Table 6: Design – Logic

Flag	Definition
Re-entry	The well to be converted into a geothermal system has already been designed and drilled. The operations required to workover the well will provide unique challenges that cannot be captured well in the proposed classification system.

Defining the function of the well allows the design to be specifically adapted. The design requirements of a production well can vary significantly from an injection well as they will be subject to different load cases and potentially exposed to different working fluids.

The five functions in Table 7 have been defined with a focus on design considerations, rather than being an exhaustive list:

Table 7: Design – Function

Function	
Selection	**Definition**
Injection	Used to inject or re-inject a cool liquid
Production	Used to produce a hot fluid
Dual	Fluids that are injected and produced from the same well
Storage	Hot fluids are circulated or injected, before being stored for a period with the possibility of being produced from the same well.
Data Acquisition	Wells specifically drilled for exploration, appraisal, or long-term monitoring purposes

The geometry of a well is defined by the required final hole diameter, total number of sections, and the depth of the well (refer to Table 8). These fundamental parameters can reveal a lot about the well and be indicative of the time required to drill the well, the requirements for surface equipment (e.g., the wellhead and the size of rig).

The final hole diameter of geothermal wells tends to be larger than oil and gas wells and can reach up to 12-1/4 in. [Bush et Siega, 2010], with some feasibility studies considering up to 14-3/4 in. The number of sections depends on the location the well is being drilled, the geology, the formation pressures, and the existence of formations to be isolated (e.g., shallow freshwater aquifers).

Knowing the final hole diameter and the number of sections helps determine the minimum diameter of the surface section and the first section where a Blowout Preventer (BOP) will be installed.

The vertical depth of the well indicates the feasibility of a well, as deeper wells being more expensive and technically challenging to drill and complete. As with most measurements, it is critical that any depth is accurately referenced, as the classification is used at the early stages of a project. The vertical depth is referenced to Ground Level.

Table 8: Design – Design Parameters Attributes

Well Geometry	
Attribute	**Definition**
Final Hole Diameter	The drilling diameter of the final hole selection, which is frequently referred to as the production hole size. This is defined as standard oilfield diameters between 3-3/4" and 17-1/2".
Number of Sections	The total number of sections, including the final or production hole, required to reach the objectives of the well **NOTE:** The conductor pipe is excluded, as it is commonly installed by civil works before the arrival of the drilling rig.
Vertical Depth	The maximum vertical depth of the well, when measured from Ground Level

The most important design parameters for a well is the maximum temperature and pressure it will encounter. Both parameters detail the selection of casing, wellhead equipment, and cement recipes used to construct the well.

The maximum temperature must be defined as the maximum bottom hole static temperature encountered at the deepest part of the well (i.e., maximum true vertical depth). The maximum pressure is defined as the highest surface pressure the well will have to contain during construction or operation and will be used to determine the pressure rating of the wellhead, well control equipment and casing. Refer to Table 9.

If stimulation of the well is required, such as for EGS, then the maximum pressure exerted on the well may occur after drilling is complete. Therefore, a distinction between the maximum pressure of drilling and stimulation is required to confirm well control equipment is not oversized.

Table 9: Design – Design Parameters Attributes

Design Parameters	
Attribute	**Definition**
Maximum Temperature	The maximum bottom hole static temperature encountered at the deepest part of a well (i.e., maximum true vertical depth)
Maximum Pressure	The maximum surface pressure a well may encounter during drilling or operational phases

Wells that require stimulation (e.g., those undergoing hydraulic fracturing) demand particular attention during the design phase, especially when evaluating the pressure ratings of equipment. These wells should be clearly distinguished from other types due to their unique operational demands. Moreover, scaling and corrosion are critical considerations that can greatly influence the well's design.

Scaling occurs when mineral deposits accumulate within the well or equipment, which can reduce the efficiency and performance of the well, requiring careful consideration of preventive measures or intervention strategies during the design process. Conversely, corrosion poses a critical threat to well integrity. Corrosion can arise from several factors, including the presence of hydrogen sulfide (H_2S) or carbon dioxide (CO_2) in the working fluid, the introduction of aerated fluids (containing oxygen (O_2), or exposure to chlorine (Cl). Selecting appropriate casing materials or incorporating corrosion-inhibiting measures is essential to mitigating these risks and confirming the long-term integrity of the well. Refer to Table 10.

Table 10: Design – Flags

Flag	Definition
Stimulation	Injection of high-pressure fluids to fracture the formation and enhance the flow from the reservoir
Scaling	A potential for mineral scale to form within the well or associated equipment
Corrosion	The presence of H_2S, CO_2, O_2, or Cl in the produced or injected fluid

6.0 Construction

This category defines the classifications for selecting the appropriate surface and well control equipment, downhole pressure control methods, and downhole tools required for well construction. These tools must perform under varying temperatures and pressures, and the classifications ensure that selections align with the specific demands of the construction environment.

The circulating temperature during drilling operations determines the temperature rating of downhole tools, regardless of whether they are constrained by elastomers or electronics. Additionally, return temperatures play a critical role in defining the specifications for well control equipment and assessing personnel safety risks. For example, return fluid temperatures exceeding 68 °C (150 °F) can cause second-degree burns in less than one second upon skin contact [American Burn Association, 2013]. The circulating temperature is the maximum expected bottom-hole temperature during fluid circulation in the well construction phases (refer to Table 11).

- The temperature range classifications were determined based on several key considerations within the Oil and Gas sector, including: Downhole Electronics Nomenclature. Industry standards classify temperatures as follows:
  - Normal: Up to 150 °C (300 °F)
  - High Temperature: 150 °C to 175 °C (300 °F to 350 °F)
  - Ultra-High Temperature: Above 175 °C (350 °F)
- BOP Elastomer Standards. The standard operating range for Blowout Preventer (BOP) elastomers is commonly recognized as -18 °C to 121 °C (-0 °F to 250 °F). The specific classifications for elastomer performance are detailed in API Specification 16A.

- Downhole Mud Motor Elastomers. Standard elastomers, such as Nitrile Butadiene Rubber (NBR), perform effectively up to approximately 120 °C (250 °F). For higher-temperature applications, High-Temperature Elastomers (HTE) can be employed, with functionality extending to 180 °C (356 °F).
- Sector-Specific Temperature Perception. Temperature range nomenclature in the Oil and Gas sector tends to skew towards lower thresholds. For instance, “Ultra-High Temperature” in Oil and Gas (above 175 °C) would be considered as potentially moderate in geothermal operations, while “Standard” temperatures up to 120 °C (250 °F) are relatively low by geothermal standards.

Based on these considerations, the classification and associated temperature ranges in Table 11 were established to provide a comprehensive framework for tool and material selection:

Table 11: Construction – Circulating Temperature

Circulating Temperature		
Classification	Definition	
	Metric Units	Imperial Units
Low	<120 °C	<250 °F
Medium	120–175 °C	250–350 °F
High	>175 °C	>350 °F

Understanding pressure regimes is critical in geothermal operations, as they dictate the design and execution of drilling and well control strategies. Each pressure regime (e.g., sub-hydrostatic, hydrostatic, and over-pressured) poses unique challenges that directly influence the selection of drilling fluids, equipment, and safety measures. Properly identifying and preparing for these regimes ensures well stability, minimizes risks (e.g., kicks and blowouts), and enhances overall operational efficiency.

Table 12 summarizes these classifications.

Table 12: Construction – Pressure Regime

Pressure Regime	
Classification	Definition
Sub-Hydrostatic	Formation pressure below the hydrostatic gradient due to fluid depletion or escape
Hydrostatic	Formation pressure is equal to the weight of a water column (0.098bar/m or 0.433psi/ft) extending from the surface to the depth
Over Pressured	Formation pressure exceeds the hydrostatic gradient due to artesian conditions, fluid trapping, thermal expansion, or tectonic forces

In geothermal drilling, Underbalanced Operations (UBO) and Managed Pressure Drilling (MPD) offer significant advantages when used selectively or combined based on the specific challenges of the geothermal well (e.g., managed sub-hydrostatic, over-pressured pressure regimes, fractured formations, or desired reservoir outputs). UBO enables optimal reservoir management and productivity enhancement whereas MPD provides safe pressure control and mitigates well control risks. Refer to Table 13.

Table 13: Construction – Flags

Flag	Definition
UBO & MPD	Intentionally maintaining wellbore pressure below formation pore pressure to allow controlled influx of formation fluids to the surface Managed Pressure Drilling (MPD) is an adaptive process for precisely controlling the annular pressure profile in the wellbore to avoid continuous influx of formation fluids, with any incidental influx managed safely.

7.0 Drilling Complexity

The drilling complexity category represents the demands placed on the drilling Bottom Hole Assembly (BHA), including the downhole tools and drill bit, to achieve the desired well objectives. This complexity is influenced by factors such as the strength of the rock being drilled, which dictates the performance and durability requirements of the BHA. The trajectory of the well, including its directional path and any deviations, impacts the precision and capabilities needed from the tools. Additionally, the need to drill multiple wellbores or sidetracks increases operational complexity, while requirements for wellbore intersections add further precision demands. Together, these factors affect the drilling duration by influencing the Rate of Penetration (ROP) and may necessitate additional steps or specialized tools to meet operational objectives.

The strength of the rock must be classified as per the predominant Unconfined Compressive Strength (UCS) of the formation that will impact the delivery of the well the most. Refer to Table 14.

Table 14: Drilling Complexity – Predominant UCS

Predominant UCS			
Classification	UCS Range		Rock Type Examples
	Metric Units	Imperial Units	
Low	<58 MPa	<8 kpsi	Soft shale, weathered limestone, chalk, and weak sandstone
Medium	58–110 MPa	8–16 kpsi	Stronger sandstone, limestone, siltstone, and dolomite
High	110–220 MPa	16–32 kpsi	Granite, basalt, gneiss, and quartzite
Very High	>220 MPa	>32 kpsi	Dense granite, quartzite, and some basalts

Generally, as the classification of predominant UCS increases, drilling rates and length of bit runs tend to decrease. However, interbedded formations pose unique challenges for optimizing the drilling BHA, selecting appropriate drill bits, and setting effective drilling parameters (refer to Table 15). Formations with fluctuating rock strengths or alternating layers of different lithologies require special consideration, as the varying properties can significantly impact drilling performance and tool wear. Designing for these conditions requires a tailored approach to ensure operational efficiency and minimize risks.

Table 15: Drilling Complexity – Flag 1

Flag	Definition
Interbedded	Formations consisting of alternating layers of different rock types with varying properties, such as strength, hardness and abrasiveness

The Directional Difficulty Index (DDI) is a valuable measure for assessing the complexity of directional drilling operations because it provides a quantifiable representation of the challenges posed by well geometry and path [Oag et Williams, 2000]. By incorporating factors such as measured depth, along-hole displacement, and tortuosity, DDI offers a consistent and objective way to evaluate well difficulty. The DDI is calculated as follows:

$$DDI = Log_{10}\left[\frac{MD\ x\ AHD\ x\ Tortuosity}{TVD}\right]$$

In this formula, MD = measured depth in ft, AHD = along hole displacement in ft, Tortuosity = cumulative change in angle along well path in degrees, and TVD = true vertical depth in ft.

A comprehensive well path with detailed survey data (e.g., encompassing measured depth, inclination, and azimuth) is required for accurately calculating the DDI. However, general classifications can be defined based on the representative DDI range, as illustrated in Table 16.

Table 16: Drilling Complexity – Directional Difficulty Index

Directional Difficulty		
Classification	**DDI**	**Well Type**
Low	< 6	Relatively short wells with simple profiles and low tortuosity
Medium	6–6.4	Either shorter wells with high tortuosity or longer wells with lower tortuosity
High	6.4–6.8	Longer wells with relatively tortuous well paths
Very High	> 6.8	Long tortuous well profiles with a high degree of difficulty

- To illustrate the relationship between different well trajectories and their respective DDI scores, four examples are provided (refer to

Table 17 and Figure 3):

- High Enthalpy Well: A simple J-shaped trajectory with a build to approximately 30° inclination and a total measured depth of 1,710 m (5,610 ft).
- Low Enthalpy Well: A deviated well featuring multi-laterals within the reservoir, reaching a maximum inclination of 70° and a total measured depth of 2,200 m (7,218 ft).
- EGS Well: A horizontal well with a lateral drain length of 1,600 m (5,249 ft).
- ACL Well: A deviated well path forming the outermost lateral of a multi-lateral well, with a total measured depth of 8,400 m (27,559 ft).

Table 17: Directional Drilling Index – Example Trajectories

Trajectory	MD		TVD		AHD		Tortuosity	DDI	Classification
	m	ft	m	ft	m	ft	deg	-	
High Enthalpy	1,710	5,610	1,603	5,258	427	1,400	30	4.65	Low
Low Enthalpy	2,200	7,218	1,560	5,118	1,152	3,780	84	5.65	Low
EGS	4,400	14,436	2,615	8,579	2,176	7,138	125	6.18	Medium
ACL	8,400	27,560	4,560	14,960	4,180	13,714	218	6.74	High

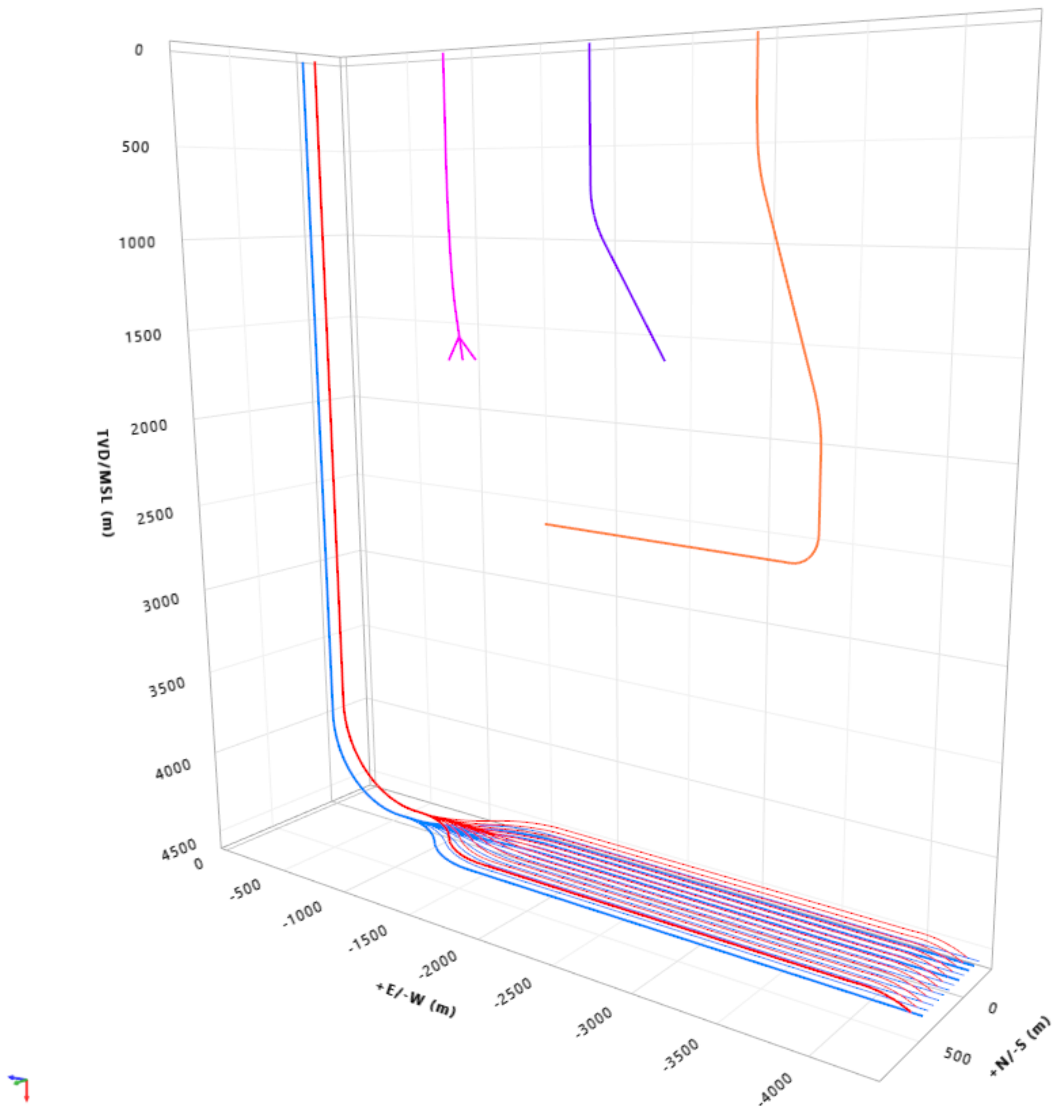

Figure 3: (Far Left) ACL Producer and Injector, (Mid-Left) Low Enthalpy Multi-Lateral, (Mid-Right) High Enthalpy, (Far Right) EGS Well

The DDI exclusively reflects the complexity of the well path and does not account for additional challenges such as multilateral drains (i.e., drilled to enhance well productivity) or trajectory interceptions, often associated with ACL. Both challenges are illustrated in Figure 3.

Table 18: Drilling Complexity – Flag 2 and Flag 3

Flag	Definition
Multilateral	A well design incorporating multiple branches (i.e., laterals) extending from a single main wellbore, typically used to increase reservoir contact and enhance productivity
Interception	The intentional targeting and intersection of one wellbore with another, often for purposes such as reservoir connectivity, production enhancement, or ACL

NOTE: If the well design incorporates multiple branches, then the outermost or most deviated branch should be considered when calculating the DDI, as illustrated in Figure 4.

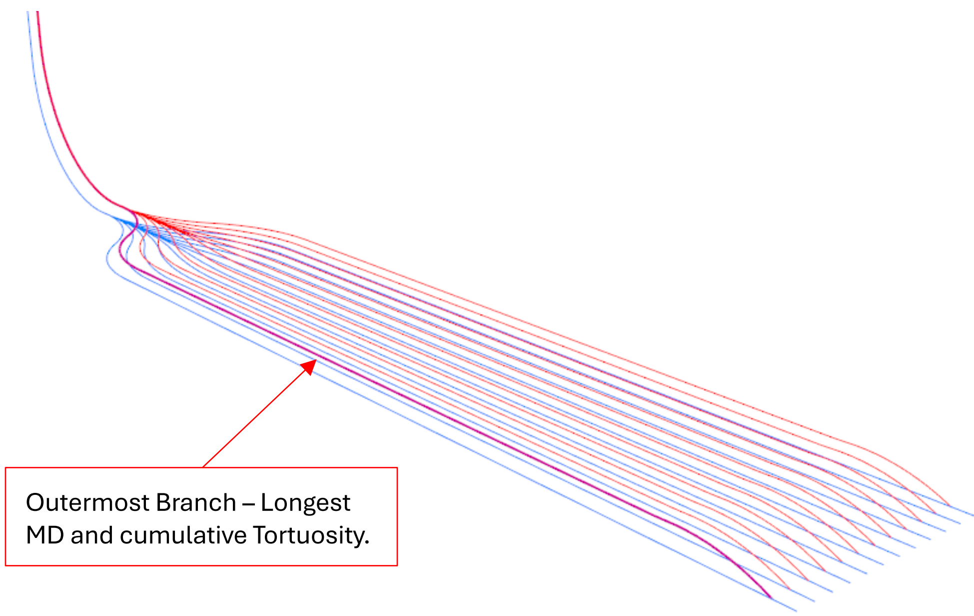

Figure 4: ACL System – Outermost Branch

8.0 Well Control

Well control is crucial to ensuring the safety of personnel and protecting the environment when drilling a well. It is vital to understand the risks associated with the formations being drilled, the state of the in-situ fluid, and the presence of hydrocarbons and toxic gases. A clear distinction between the well control methods applicable to reservoir-dependent and reservoir-independent geothermal wells must be established. For reservoir-dependent wells, the state and properties of the reservoir fluid dictate the appropriate well control techniques.

In contrast, reservoir-independent wells typically rely on conventional well control methods during the well construction phase. However, this definition should be tested once permeability and fluids have been introduced to a reservoir-independent system. For example, in field developments of an EGS, where there is a risk of encountering charged fracks, the well control method, equipment, and personnel training needs to be adapted.

In reservoir-dependent systems, the state of the fluid to be controlled will dictate the method of well control to be employed. The state of the fluid is dependent on its temperature and pressure. A typical Pressure-Enthalpy chart can illustrate the regions where the state of the fluid changes from liquid to a two-phase fluid (e.g., liquid and vapor) to vapor. Sanyal proposed a classification system for geothermal resources based on temperature and the related application of technology to generate electricity [Sanyal, 2005], as illustrated in Figure 5.

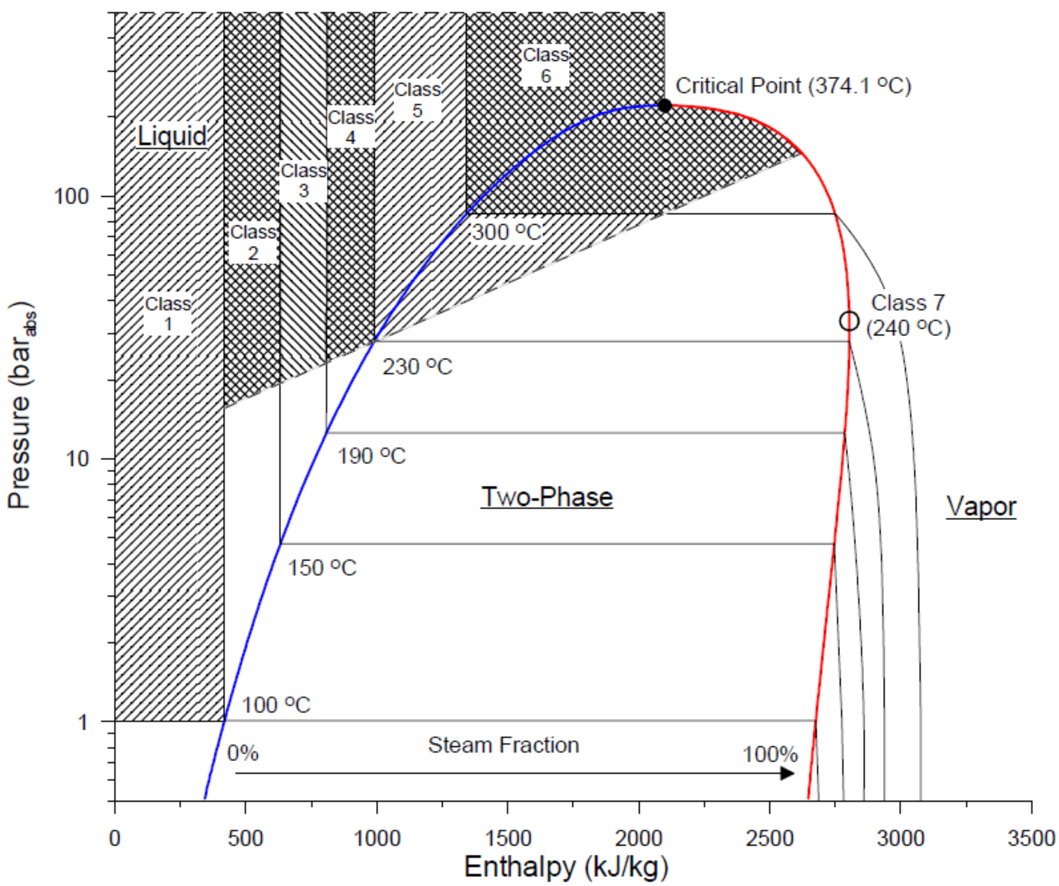

Figure 5: Pressure – Enthalpy Graph for Water (Sanyal, 2005)

The state of fluid changes when the combination of pressure and temperature crosses the liquid saturation line, as illustrated by the blue line in Figure 5. This is referred to as the liquid's flash point, changing from a liquid to a two-phase fluid (i.e., mixture of liquid and vapor) (refer to Table 19). These conditions can be met in a well control situation and can lead to a self-sustaining process where boiling can occur over most or all the well depth (NZS 2403:2015).

Superheated steam (i.e., vapor) geothermal fields occur under highly-specific conditions and are found in select locations worldwide, including Kamojang, Indonesia, the Geysers in California, and Larderello, Italy [Sanyal, 2005]. In these fields the production interval is drilled with air to avoid formation damage and plugging, resulting in the drilling returns including produced steam from the reservoir [Finger and Blankenship, 2010]. This process requires the use of a rotating head with the gaseous returns being sent through a manifold called a “banjo box”.

The in-situ state of the reservoir fluid should be used as the initial conditions to determine the well control classification. However, due to the potential for a hot fluid to flash under certain conditions, the likeliness of this occurring must be assessed to determine the well control classification as illustrated in Figure 6. The complex relationship between the fluid's pressure, temperature, and composition must be understood to help with this determination.

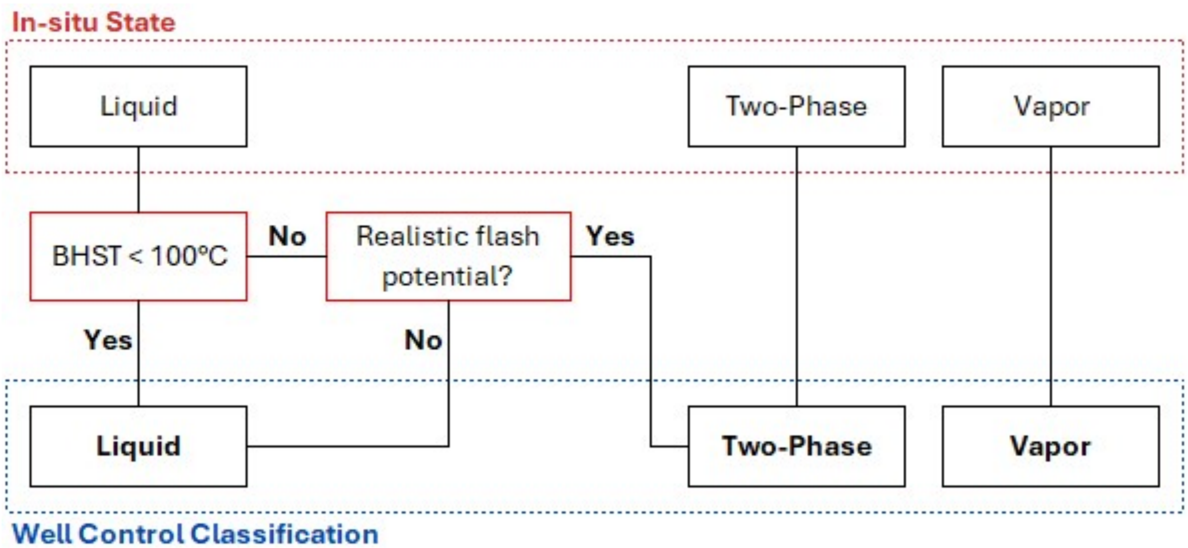

Figure 6: Well Control Flowchart

NOTE: Figure 6 assumes standard atmospheric pressure (1 bar or 14.7 psi), a liquid can boil or flash to steam at lower temperatures at pressures below the standard atmospheric pressure (i.e., at drilling sites at high altitudes).

Table 19: Well Control – Expected Phase

Classification	Definition
Liquid	There is no (i.e., negligible) chance for a two-phase fluid to be encountered. Conventional well control methods, equipment, and training can be employed to drill the well.
Two-Phase	The in-situ state of the reservoir fluid is two-phase, or there is a significant possibility that fluids in the well can flash. Specific well control methods (e.g., quenching), equipment, and training are required to drill the well safely.
Vapor	The method employed to drill reservoirs results in permanent production of the in-situ fluid which requires specific well control methods, equipment, and training to drill the well safely.

In the oil and gas industry, the presence of hydrocarbons is assumed to be the primary target. However, hydrocarbons are typically absent in geological settings that are common or advantageous for geothermal wells (e.g., volcanic regions, metamorphic zones, or crystalline basements). To address this distinction, a flag has been introduced to indicate the potential presence of hydrocarbons in any well section, as detailed in Table 20. While hydrocarbons in intermediate sections (e.g., crossing a sedimentary basin before reaching the crystalline basement) may pose some risk, the risk is significantly lower than those associated with drilling reservoir sections in oil and gas wells. This reduced risk could justify less stringent practices, such as less frequent BOP testing when drilling production sections in reservoir-independent geothermal wells without the threat of hydrocarbon or fluid kicks.

Toxic gases, including H_2S, CO_2, and occasionally methane (CH_4), are more commonly encountered in geothermal wells due to the interaction of geothermal fluids with surrounding rocks and the elevated temperatures typical of these environments. The Toxic Gas Flag should be selected when there is a significant risk of exposure to these gases.

Supercritical geothermal wells, which access fluids exceeding water's critical point (374°C and 221 bar), offer immense power potential due to their high enthalpy. However, these wells pose significant control challenges, including extreme temperatures, pressures, and corrosive conditions. To address these risks, a dedicated flag has been introduced, as detailed in Table 20.

Table 20: Well Control – Flags

Flag	Definition
Hydrocarbons	The potential presence of hydrocarbons in any section of the well.
Toxic Gases	The potential presence of toxic gases such as H_2S, CO_2, and CH_4 in any section of the well.
Supercritical	The potential to encounter fluids at temperatures and pressures exceeding the critical point of water (374.3 °C and 221 bar).

Appendix A Abbreviations and Conversions

A.1 Abbreviations

Abbreviations	
ACL	Advanced Closed Loop
AGS	Advanced Geothermal Systems
AHD	Along Hole Displacement
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
CH_4	Methane
Cl	Chlorine
CO_2	Carbon Dioxide
CLGS	Closed Loop Geothermal Systems
DDI	Directional Difficulty Index
EGEC	European Geothermal Energy Council
EGS	Enhanced Geothermal Systems
H_2S	Hydrogen Sulfide
HDR	Hot Dry Rock
HSA	Hot Sedimentary Aquifers
HTE	High-Temperature Elastomers
IADC	International Association of Drilling Contractors
IEA	International Energy Agency
IGA	International Geothermal Association
MD	Measured Depth
MPD	Managed Pressure Drilling
NBR	Nitrile Butadiene Rubber
O_2	Oxygen
ROP	Rate of Penetration
TVD	True Vertical Depth
UBO	Underbalanced Operations
UCS	Unconfined Compressive Strength
UTES	Underground Thermal Energy Storage

A.2 Conversions

Unit	Conversion
1 metric tonne (mT)	2,205 lbs
1 deg C	(1 deg C x 9/5) + 32 deg F
1 bar	14.504 psi
1 MPa	145.04 psi
1 m	3.281 ft

Appendix B: References

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