Exploration Cost Benchmark: Reference Manual

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Nomenclature

AFE – Authority for Expenditure
CPI – Consumer Price Index
CUD – Cost per Unit Depth, Cost/ft or Cost/m
DPI – Drilling Price Index
EIA – US Energy Information Agency
HPHT – High Pressure, High Temperature
IOC – International Oil Company
NOC – National Oil Company
OPI – Oil Price Index
OPIM – Oil Price Index Multiplier
PSAC – Petroleum Services Association of Canada
ROP – Rate of Penetration

1. Introduction

1.1. Background and context

This project entails the development of a web application that will serve as a database for exploration cost benchmark.

The New Petroleum Producers Discussion Group is a cooperative network of 31 emerging producer countries. Many of the members are from Africa. The main aim of the New Producers Group is to improve capacity and governance through knowledge sharing between emerging producers. This initiative, which is co-organized by Chatham House, the Commonwealth Secretariat and the Natural Resource Governance Institute, is non-profit and independent from commercial interests. The African Natural Resources Center is a partner of the initiative. At its fifth annual meeting in October 2017, the New Petroleum Producers expressed a clear need for better understanding of the sources and make-up of exploration costs for upstream petroleum operations. A working group was established to consider practical ways to understand benchmark and possibly codify procedures to guide government officials who are not fully conversant with detailed exploration costs. This exercise is considered of significant value to new producers due to the potential benefits in the enhancement of regulator due diligence capacity, the minimization of revenue leakage the enhancement of government audit capabilities. The New Producers Group and the African Natural Resources Center are collaborating to produce practical tools to support exploration cost benchmarking.

1.2. Objectives and features of the cost benchmark platform

The main objective of the cost benchmark platform is to serve as a tool for regulators, auditors and other stakeholders of the oil and gas industry, to get acquainted will major stages and activities of exploration drilling and quickly estimate the cost of drilling a well in their countries and in a particular basin in the country. It consists of a **web application** with the following features:

- A regional costs datatable used for quick and high level comparison of the booked cost (in US$/ft or US$/m) with the historical costs achieved in same region
- A reference well with costs, used to generate benchmark costs to compare with booked and/or AFE costs entered by end-users.
- A straightforward procedure used to generate (build) benchmark costs
- A scalable and extensible database of costs of exploration from different countries (entered by end-users) and their underlying uncertainties;
- A convivial user interface that will enable users to input costs of executed projects and compare those with reference costs in the database

1.3. End users of the framework

The primary end users of the application are regulators and auditors of the oil and gas industry. The application aims at giving them more confidence of what major factors have costs repercussions and helping them to much easily determine the deductible expenses and firm up tax liabilities.
Oil and Gas exploration drilling activities

Exploration drilling activities are those following immediately the identification of a drill-ready prospect during oil and gas exploration. It consists of drilling one or many wells through the prospect to confirm existence of hydrocarbons in quantities that are enough to warrant developing the field for production. Thus exploration wells consist of two broad categories: (1) Wildcats and (ii) appraisal wells.

Wildcats are drilled to determine existence of hydrocarbons bearing formations. They are most commonly known as exploration wells in the sense that little is known about the subsurface geology with certainty, especially the pressure regime. Therefore, the drilling crews must be appropriately skilled, experienced and aware of what various well parameters are telling them about the formations they drill. The crews must operate top-quality equipment, especially the blowout preventers, since a kick could occur at virtually any time.

A critical step during drilling exploration well is formation evaluation. It is the stage in which information about the presence or absence of hydrocarbon-bearing reservoirs is acquired. Time spent coring, logging, reaming, and testing is a very important consideration in drilling time and thus cost. The well will be surveyed with logging tools both from the MWD/LWD and wireline logging. The well will be tested to determine pressure, temperature and obtain fluid samples. Thereafter the well will be plugged and abandoned or plugged for future re-entry or usage as observation well.

Appraisal wells are drilled subsequent to wildcats to qualify and quantify the reservoir in the sense that they aim to confirm the size and structure of the field. They may have a horizontal or highly deviated section. Logging and log interpretation provide data on the hydrocarbon-bearing rocks. A series of tests amongst which Drillstem and/or Surface testing, might be performed. Drillstem test can be performed in an open or cased hole and generally in a relatively short period. Surface testing would include different types of tests (Banker's test, buildup test, drawdown test, production test, etc.) and may last for few days or a lot more. Extended testing may even last for 90 days. If appraisal confirms a commercial reservoir, the operator may then proceed to development. An appraisal well may be equipped with temporary completion close to actual completion of a production well in the development phase. Appraisal wells can be abandoned after drilling or kept as future production wells. An appraisal well usually has a chance of success greater than an exploration well. It is also less constrained than an exploration well, though drilling crew must also be appropriately skilled and drilling equipment of top quality. This is because exploration well has provided information useful to reduce uncertainties, especially on the pressure regime in the formation. In order to eliminate the cost of well suspension and re-entry, the testing program may follow-on immediately after completion of the drilling phase. Figure below summarizes typical phases of well drilling.

Figure 1 xxxxxxx Table 1 summarizes activities that are executed in order to drill a wildcat and an appraisal well.

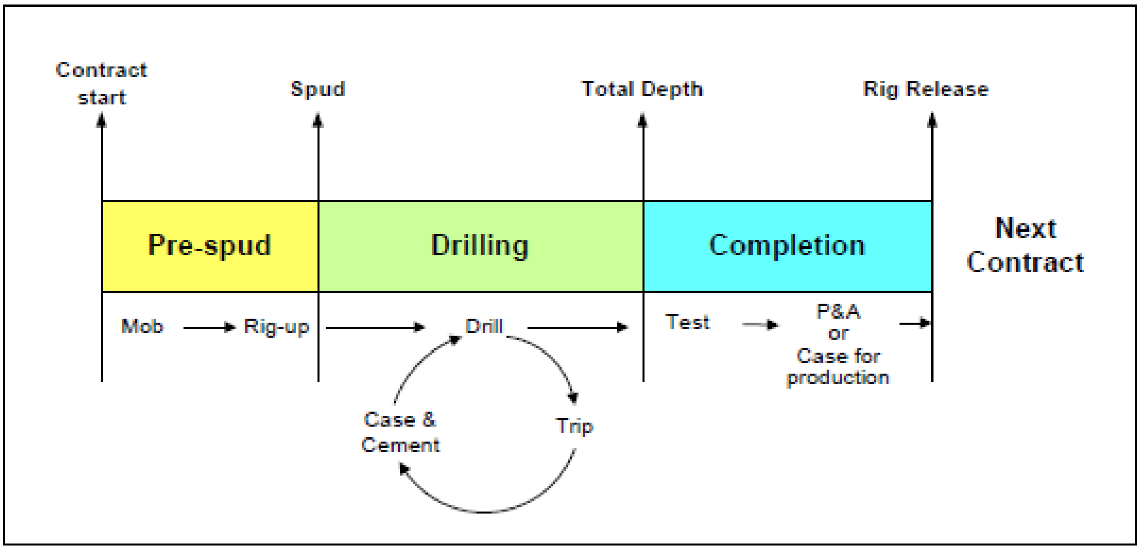

Table 1: activities executed during drilling exploration wells

activity		Wildcat	Appraisal
Well planning and studies		X	X
Mobilization, demobilization and site survey, furbishing/construction		X	X
drilling	Rig rental	X	X
	Drilling	X	X
	Mud logging		
	Casing & cementing	X	
	Wireline logging	X	X
	Coring	X	X
Well testing	Drill Stem Test	X	X
	Modular Dynamic formation Tester (MDT)	X	
	Extended Well Testing		X
	Buildup, drawdown, multirate, banker's test, production tests		X
Completion	Production casing		X
	Production casing		X
	Plug and abandoned	X	
	Plugged for reentry	X	X
Waste disposal		X	X
Others	Logistics, catering, etc.	X	X

3. Oil and Gas drilling costs drivers and factors

Exploration drilling costs are accrued from execution of drilling and pre and post drilling activities. They depend on the one hand on specificities of the project and the capacity of the organization to control costs and use its position in the market and the economies of scale to keep costs low and on the other hand, on the position of the country with respect to supplies market, the stage of its infrastructural development, the degree of maturity of its oil and gas industry and related support infrastructure, the local workforce and local suppliers' capabilities, the oil price and related level of drilling activities in the world amongst others. In the cost benchmark platform, project specificities are technical and operational and are referred to as cost drivers, whereas organization's and country's specificities and the oil price are referred to as cost factors. Costs can be grouped into many categories which are related to the activities (drilling, pre-drill and post-drill). Figure 2 below shows typical categories of well costs and their contribution (%) to the total well cost onshore. Drilling costs in turn can be grouped into two broad groups: tangibles and intangibles.

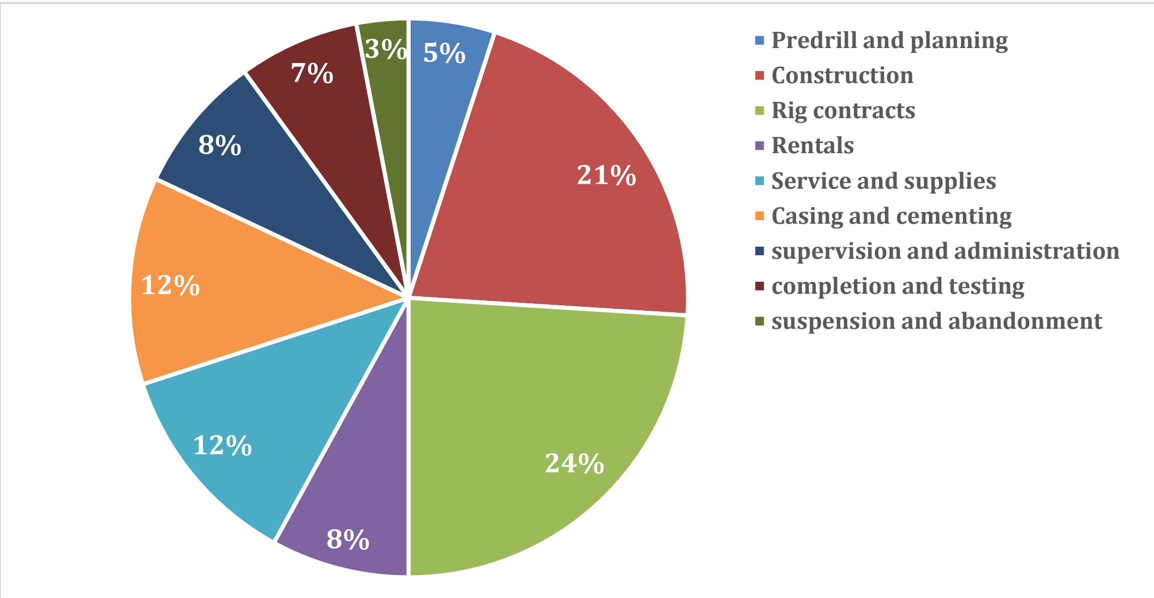

Figure 2: Well cost categories and their contributions in percentages to the total cost onshore (adapted from PSAC, 2015)

3.1. Drilling Cost Drivers

3.1.1 Onshore cost drivers

Onshore drilling costs are majorly driven by the rig contract costs, which include rental and associated services and may account to up to 40% of the total cost of the well. The longer the drilling time the higher the rig costs because the rig is normally charged at a daily rate or a combination of turnkey and daily rate. There are many parameters and events that affect the time and cost to drill a well. Measurable parameters include the physical characteristics of the well, geology, and drill parameters. Non-measurable parameters are operator experience, wellbore quality, proximity to support infrastructure, project management skills, team communication, leadership, etc.

Physical parameters determine well complexity, which arise from diverse factors, including the nature of the geologic formation, depth of the target, size of the reservoir sands, trajectory of the wellbore and technology applied. Though difficult to quantify, well complexity will affect the drilling costs dramatically or not, depending on the experience of the operator and the technology used. In general, more complex wells may result in higher drilling costs. Some indicators of complexity are abnormally pressured formations, High Temperature and High Pressure conditions (more than 300F and 10000psi), the Aspect Ratio of the well (aggregate curvature of the well) and the Extended Reach Ratio (ratio of total depth to total vertical depth).

Well complexity along with operator's experience and technologies used are often linked with common problems encountered in drilling a hole. A typical problem is that something breaks inside the well, such as a piece of bit or drill string, or something falls down the wellbore, such as a wrench or other tool. If fishing is unsuccessful, the hole will either be side-tracked or the driller will set a whip stock, and in the worst case, a new hole may need to be spudded. Other drilling problems may include stuck pipe, sloughing shale, lost mud circulation, formation damage, embrittlement, and abnormal pressure.

Another important cost driver is the drilling fluid. The cost of drilling fluid represents 5% to 10% of the total well cost. Experienced mud engineers and good drilling practices can help reduce the cost of the drilling fluids. When many wells are drilled or an appraisal well is drilled subsequent to a wildcat, the drilling mud can be recycled and reused.

3.1.2. Offshore cost drivers

Offshore cost drivers are similar to those of onshore drilling. The same well challenges and complexities are encountered offshore with different degrees of severity and level of influence on the cost of the well. Key cost drivers for offshore drilling include water depth, well depth, reservoir pressure and temperature, field size, and distance from shore.

A common decision in offshore operations involves the use of Logging While Drilling (LWD) vs. wireline (WL) techniques. Adding LWD to a directional well can add a few hours to each hole section for rig up and servicing, while drill pipe-conveyed WL logging may take days leaving the rig idle. Total formation evaluation cost may be less with LWD in cases where the well is deep and highly deviated, rig day rates and penetration rates are high.
Rig contract costs is a much larger share of the total cost for offshore than for onshore drilling. It can be in excess of 50% of the total well cost. Offshore drilling may be delayed significantly by the weather. Weather downtime can severely affect drilling operations and drive costs up.

- A too severe weather for operations involving supply boats may lead to delay if stock levels on the rig decline to a critical level;
- A bad weather may slow anchoring-up and moving time;
- weather may be too severe for drilling to occur;
- extreme weather may result in damaged or lost drill strings and risers;
- etc.

If operating limits are exceeded because wave heights, ocean currents, or eddies are too strong, drilling operations will be temporarily abandoned and resumed when conditions fall within the operating capabilities of the equipment. This situation is generally termed Waiting on Weather (WOW).

In the light of the foregoing, it is obvious that many problems during drilling may require suspension of the activity. It is custom that most contracts specify a certain amount of “free” downtime (24 hr/month is typical), but outside this allowance, the contractor does not receive payment for the time the rig is inactive. Also, delays that are not directly accountable to the driller are usually charged at a reduced rate.

Drilling itself is also a much larger share of total well costs in offshore development than in onshore development. Tangible and intangible drilling costs can exceed 60% whereas onshore they typically represent only about 30% to 40% of total well costs. Table 2 below recapitulates the key cost drivers onshore and offshore

Table 2: Key costs drivers important for costs benchmarking.

Cost driver	Onshore	Offshore
Well depth	**X**	**X**
Water depth		**X**
Rig load capacity	**X**	**X**
Waiting on weather		**X**
Well complexity		
Abnormal pressure[1]	**X**	**X**
HTHP	**X**	**X**
Extended Reach Ratio	**X**	**X**
Aspect Ratio	**X**	**X**
Severe problem		
Side tracked	**X**	**X**
New spud	**X**	**X**
Fishing	**X**	**X**

3.2. Drilling Cost Factors

3.2.1. Organizational cost factors

Low oil prices and regulators’ monitoring compel companies to control costs, increase efficiencies, and access improved technologies. Low oil prices also drive services and supply costs down. Operators can leverage their experience in similar basins or analogue reservoirs to anticipate drilling challenges and avoid well overdesign that is common in new basins or unexplored frontier areas. Experience of the operator in project management is also an important factor that can help drive the cost down. The position and influence of the operator in the industry are also important. A large multinational can rely on relationship with suppliers, contractors and large commands to significantly reduce drilling costs. It may also have access to best technologies that will improve drilling performance and as a consequence drive the cost down, even in frontier areas. Conversely an operator lacking experience and having little influence in the industry may cause costs to soar. Drilling technology improvements include longer

[1] Geopressures, unanticipated low pressures

laterals, improved geosteering, increased drilling rates, minimal casing and liner, multi-pad drilling, and improved efficiency in surface operations.

It is worth noting that operators (with approval of the government) majorly decide where to drill, how to drill, and how to let the contract. The contract type (day rate, turnkey, combination) and duration, job specification (one well, multiple wells, sharing mobilization and demobilization costs, etc.), supply and demand conditions at the time and negotiating strategies are important factors in determining drilling time and cost.

Many different rigs can be used to drill an offshore well; rig selection depends upon such technical factors as type of the well being drilled, water depth and environmental criteria, vessel availability, type and density of seabed, expected drilling depth, and load capacity. Equipment selection involves trade-offs that balance weather risk and the potential cost of delay. Still, operator's experience and position in the market are critical factors in taking the optimal decisions.

Regulators' actions can help operator improve drilling performance. For instance, asking operators to justify nonproductive drilling time may force them to avoid nonproductive times that can be avoided and thus reduce drilling costs.

3.2.2. Country and location cost factors

Primary wellsite characteristics include geographic location and, for offshore environments, distance to the nearest onshore service station and water depth at the site. Water depth and environmental conditions expected to be encountered is a primary determinant in selection of the rig required for drilling. As the water depth increases and environmental conditions become harsher, larger and more robust rigs are required with extra hoisting capacity, mud-circulation systems, mooring systems. This goes with an increase in drilling costs.

The region and country in which a well is located is an important consideration in obtaining government regulations and permits, customs, port handling, and transportation. The maturity of the infrastructure support services and the knowledge and experience of contractors and suppliers will also play a role in determining drilling cost as also earlier recognized by porter (1990) and Kostovski (2012). They both emphasized on the competitive advantage of a nation and advantages of clusters to a particular industry. Some of the competitive advantages derived as a result of geographic proximity are reduced costs of tangible and intangible inputs development of a common supplier base, availability of skilled labor, spill-over of technical know-how and the diffusion of the working knowledge of a particular industry into individuals and firms. Likewise, clusters can provide a network of supporting firms that supplies inputs and sub-contracting functions more efficiently and at lower costs.

It is worth noting that security issues can cause drilling costs to rise due to high risks allowances. And even though security in the country of operations is good, security issues in neighboring countries may also attract high risk allowances.

3.2.3. Global market and economics' factors

Drilling activities levels are tied to achievable oil prices. The higher the oil prices the higher the activity level and as a consequence higher demands for drilling rigs, services and consumables. Equally, low oil prices result to low demand for drilling rigs, services and consumables. Thus the cost of drilling a well is closely tied to oil price volatility, which dictates the dynamics of offshore and onshore drilling market. The same well drilled in high oil price period will definitely cost less if it were drilled in low oil price period.

The US Energy Information Administration, EIA (2015) in a study of the cost of drilling in the US, pointed out that the rig rental rate, material and services costs are not necessarily tied to Consumer Price Index (CPI), but to a Drilling Cost Index (DCI) that reflects changes in Drilling Costs. They also identified that the DCI is an annualized record and thus of little help if costing a current well. Leamon (2006) earlier recognized the limitations of CPI to costing a current well, due to a higher dependency of drilling costs to escalation in the industry rather than price inflation. He proposed to adjust costs estimates with historical costs, to reflect fluctuations in oil prices and its effects on price escalation. He identified that future well cost may be estimated from known or estimated rig rate. His analysis led to the conclusion that 50% increase in rig costs may result in 25% increase in total onsite cost, and 100% increase in rig cost and tubulars together with 50% increase in services 'cost may lead to 60% increase of the total well cost. This is consistent with the fact rig and tubular cost may account for more than 60% of the total well cost.

In the light of the foregoing, the cost benchmark platform uses Oil Price Index (OPI) to estimate benchmark costs. The OPI reflects the contribution of the rising oil price to the escalation of prices of services and supplies in the industry. It is in this context, the ratio of the difference of the average oil price of the 12 months before the reference well was drilled and average oil price of the 12 months before the well of which the costs is being benchmarked was drilled, to the average oil price of the 12 months before the reference well was drilled. One is added to avoid negative values.

4. Exploration drilling costs

4.1. Costs categories

Drilling costs can be grouped under two broad categories: tangible and intangible costs. Tangible costs are those related to equipment and tubular goods amongst which wellhead equipment, casing strings, and packers in the context of exploration and appraisal wells. Intangible costs are those related to rentals, and services. They include rig and rig crew rates, mobilization and demobilization, logging, coring, testing and geosteering services. Figure 3 below shows a summary of tangibles and intangible costs' items.

Costs items can further be broken down into variable and fixed costs. Variable costs are also time-dependent and time-independent. Time-dependent variable costs are costs such as services and supplies, drilling rig contract and rental costs. Time independent variable costs are costs such as cement, drillbits, drilling fluids, chemicals and other consumables. Fixed costs are casing and wellheads, lump sum mobilization costs, etc. Marshall (2001) reported that time dependent costs could account for 40 – 70% of the total drilling cost. This is in line with other analysis of well costs where for offshore wells with high rig and boat rates rental costs will be toward the upper range of 70%. For land wells with relatively low rig day rates, but high time-independent costs such as civil works and equipment mobilization and demobilization, the proportion of time dependent costs will be toward 40% range. It is noteworthy that the relative proportion of time dependent variable costs for all wells may increase as the duration of the well increases.

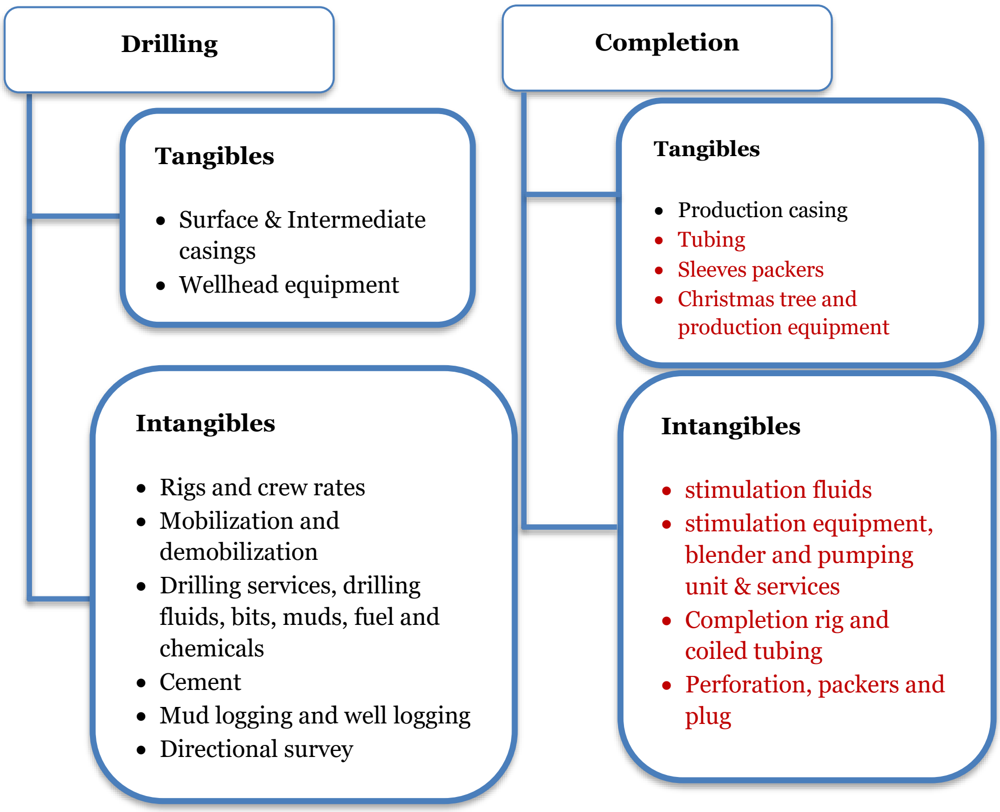

Figure 3: Summary of tangible and intangible costs items

4.2. Classes of Costs (benchmark, booked, AFE costs)

Two broad classes of costs exist and depend on the stage of the well. Before the well is drilled, its cost estimate is referred to as Authority for Expenditure (AFE) because it stands also as a request for funds. After the drilling is completed the booked costs, which is the actual cost of the well is reported in the Well Costs Report (WCR). There appears to be no convention across the petroleum industry as to what should be included in, or excluded from, a cost report, be it AFE or Booked cost. According to Williamson et al. (2004) common questions are the following: Should planning costs, or corporate or country head office costs, be allocated to the AFE? If the well is the first in the campaign, should the cost estimate include rig mobilization? It is important for regulators and auditors to have a common costs format and report procedure across operators in a country.

Kaiser (2009) also expatiated on the AFE estimation process. He described that the usual procedure is to decompose costs into general categories: site preparation, mobilization and rigging up, drilling, tripping operations, formation evaluation and surveys, casing placement, well completion, and contingencies. Several categories are typically specified, and the drilling engineer itemizes the expected time and cost per category. Each cost component is then identified and categorized into minor cost elements, and the percentage contribution of the total cost is computed to identify the key cost drivers. To improve the range of the estimate, the uncertainty of the cost drivers is frequently quantified. This forms the framework of the well budget which is then sent to management for an Authorization for Expenditure (AFE) to drill the well.

Leamon (2006) in his MSc thesis at the university of New South Wales in Australia, reported important deviations between AFE and Booked cost up to +/- 35% depending on the methods used in estimating AFE. He further pointed out a practice which is still existing in many companies, which is that well costs estimates are primarily based on time estimated to drill a 'trouble free' well with 0% Unplanned Events (i.e. no Trouble Time) and to assign a gross contingency factor that will account for possible unknowns.

It is noteworthy that the above practice often relies on experience and discrete observations of average drilling costs in different areas, regions and basins. Nowadays with advances in computing capabilities and progresses in Data Sciences and Artificial Intelligence, majors and large independents are increasingly using data mining techniques to analyze their historical data to generate more accurate predictors of costs estimates during well planning.

5. Oil and gas drilling costs database and sources

Operators routinely acquire massive volumes of drilling data and often at great expense. Yet at the same time, researchers in the field of drilling performance lament the lack of quality benchmark data with which to conduct statistical analyses of well performance. Several factors contribute to this apparent paradox. It is important to recognize that documents and databases are not knowledge. These large operators also maintain their own extensive well databases, but there is little open standardization of analysis and no public comparison of results.

Another reason for scarcity of useful and sufficient well costs and performance data in the public domain is that Oil & Gas companies regard information and knowledge base as competitive advantage.

The good news as earlier mentioned is that many of the operators are making huge investments in databases across the industry. Their data is often related to the fields, countries and regions in which they operate. Their databases can be accessible to the national oil companies or government agencies depending on the clauses on data and information in the petroleum contracts.

Some national oil companies also collect data and manage similar databases. Their data is generally limited to the petroleum domain of their countries.

There are also management and service companies that specialize in the sale of drilling and cost information acquired from industry sources at considerable costs. Their data often cover a wider scope in terms of wells, regions, countries, basins and geology but seldom contain all relevant details for drilling performance and cost analysis.

Other sources of data are journal publications, companies' annual reports, institutional reviews, etc. This data is often high level and insufficient. They give a more qualitative than quantitative trend of drilling cost and performance.

Table 3 below presents different sources of useful well drilling costs data.

Table 3: important sources of well costs data

Organization	Country	Type of Organization	Data form	Free access Yes/No
Norwegian Petroleum Directorate (NPD)	Norway www.npd.no/en	State owned regulatory agency	Data base Reports	No Yes/No
Nigerian Department of Petroleum Resources (DPR)	Nigeria www.dpr.gov.ng	State owned Regulatory agency	Reports	Yes/no
Petroleum Services Association of Canada (PSAC)	Canada www.psac.ca	Professional association	Database Reports	No Yes/No
Energy Information Administration (EIA)	USA www.eia.gov	State owned	Reports	Yes/No
Institut Francais du Petrole (IFP)	France	State owned	Reports	Yes/no
American Petroluem Institute (API)	USA www.api.org	Trade association	Reports (JAS)	No
USAID	USA www.usaid.gov	State owned	Reports publications	Yes
Other national industry regulators and organization	Many	State owned and NGO	Reports and publications	Yes/No
National Oil Companies	All countries	State owned	Database Reports	No Yes/No
International Oil Companies	Global	Private	Database Reports	No Yes/no
IHS Marktit	Global www.ihsmarkit.com	IHS	Database Reports	
Woods Mackenzie	Global www.woodmac.com		Database Reports	
ENIGMA	USA www.enigma.com		Database Reports	No Yes/No
Society of Petroleum Engineers	USA www.spe.org	Trade association	Publications www.onepetro.org	No

Organization	Country	Type of Organization	Data form	Free access Yes/No
Oil & Gas Journal	USA www.ogj.com	Private	Publications	No
Associations of drilling contractors	Various	Trade organisations	Reports publications	No

6. Developing and updating of Benchmark costs

Two approaches to costs benchmark are developed in the platform: Quick benchmark and detailed benchmark approaches. The quick benchmark approach uses a table of regional cost data, which is presented in the section related to benchmark procedures. The detailed benchmark approach is described in the following sections starting with the methodology.

6.1. Methodology

It is common to benchmark cost by looking at drilling performance first and its major indicator which is the Rate of Penetration to which the cost/unit depth (CUD - cost/ft or cost/m) is closely related. There have been two methods commonly used to determine these parameters: Experimental Design and Data Mining. In Experimental Design, one or more parameters of the drilling process are varied and the impact of the variable on ROP and CUD are observed. Data mining examines a large set of well costs data and performance and analyses them with various regression methods to establish relationships between factors of the drilling process. These relationships expressed in forms of linear or quadratic equations are used to estimate CUD and ROP. In the US, the Joint Association Survey and Mechanical Risk Index are two well documented methods used to estimate drilling cost data and complexity (Kaiser, 2009). In general, wells drilled under a wide range of conditions provide the raw data to explore the manner in which cost drivers and factors contribute to drilling costs. The disadvantage of this method is that analysis of historical cost data is difficult because it has probably not been captured accurately or in sufficient details. Also CUD may vary over time not always because of better drilling performance, but sometimes because of different market conditions.

As earlier mentioned it has also been custom in the industry to estimate drilling cost based on an ideal well drilled in ideal conditions (drilled with time estimated to drill a ‘trouble free’ well with 0% Unplanned Events) and assign large contingencies factor that will account for the unknown. The cost benchmark database is combining this approach with Experimental Design method for the beginning. The rationale behind it is that in the beginning, there will be few and very sparse data in the database to warrant any attempt of regression analysis.

The benchmark costs are estimated based on a reference well drilled in ideal conditions. The costs are categorized as described by Kaiser (2009) and presented above. The categories of this reference well are varied with multipliers of costs drivers and costs factors generated by Experimental Design. The major issue is the source of the costs data, their accuracy and reporting precision. It is often the case that without a rigorous cost accounting system, the accuracy of the booked well cost cannot be guaranteed.

To improve accuracy in early estimations, booked costs and related AFE costs are simultaneously examined to identify deviations and verify that they fall within deviations reported by operators in data used to analyze and forecast their own drilling performance. Published rigs' day rates may also be used as proxy to verify validity of well costs.

As the database is populated and will provide sufficient data to justify regression analysis, data mining and Artificial Intelligence techniques will be used to establish relationships amongst various parameters that will be used to generate and continuously update benchmark costs. A critical issue will still be accuracy of data. Therefore, end-users have to make sure that the data they enter is accurate.

6.2. Assumptions of the reference well and uncertainties in costs estimation

Two reference wells are considered for the benchmark process. An onshore reference well and an offshore reference well. The concept of reference costs follows in part the same rationale as the concept of reference Oil for oil prices such as Brent or WTI. Price of oils from different fields are determined by using multipliers (factors) calculated based on the difference in quality, proximity to markets and other country and regional specific parameters.

The onshore reference well used is a representative of commonly drilled exploration wells in almost ideal conditions (trouble free with just 5% nonproductive time). It is an onshore European well of 2000-meter (6562 ft) vertical depth with no deviated section, drilled during 40 days in 2015, for a global IOC and by a renowned contractor. There are two days spent for coring and the well is logged and abandoned. The well costed US$ 3 7 10 000 in total with cost/m of US$ 1855 or cost/ft of US$ 566.

The offshore reference well is also a representative of commonly drilled offshore exploration wells in almost ideal conditions (trouble free with just 5% nonproductive time), in shallow waters 50 m water depth and almost at shore, 1km distance to shore. It is a vertical well drilled in 52 days to a total depth 2000 meters (6262 ft). The well was drilled for a global IOC and by a renowned contractor. There are three days spent for coring and the well is logged and abandoned. It costed $US 14 740 742 in total, for a cost/m of 7370.4 US$ /m or 2247 US$ /ft.

The multipliers are adjusted to cater for other offshore situations and locations (deep waters, ultra-deep waters). This approach is further reasonable for the fact that the main focus is on categorized costs. Detailed costs help more to understand in details the items driving costs. Those will vary from well to well, and from location to location.

Other characteristics useful for the benchmark procedure are listed in table 4 below:

Table 4: Other characteristics of the reference well

Reference well characteristics
Well program

Reference well characteristics						
	number	Hole diameter (inches)	Casing diameter (inches)	Setting depth (ft)	Drilling fluid	Formation evaluation
Conductor	1		14 3/8	80	none	none
Surface casing	1	12 1/4	9 5/8	875	Fresh water	none
Intermediate casing	1	8 3/4	7	4900	Water based	wireline
Production casing	0	n/a	n/a	n/a	Water based	LWD

logging		
	type	Tool configuration
	wireline	Triple combo

Testing			
	Test type	**Tool configuration**	**duration**
	MDT wireline conveyed	standard	2 h

Coring onshore	**Coring offshore**
2 days	3 days

Rig Information						
Day rate onshore	Day rate Offshore	Load	origin	Contract type	Days onshore	Days offshore
50 000 $US	180 000 $US	200 tons	In field	turnkey	42	50

The uncertainties in costs estimation may still be acceptable and analyzed with respect to cost factors primarily. A deviation of up to 10% may be acceptable, for it is also the level of uncertainties in the booked costs and reference costs, recalling that booked costs accuracy sometimes may depend on accounting policies of operator. A larger deviation of up to 20% should be analyzed with respect to organizational and location costs factors, and cost drivers except for problems of high severity. A deviation larger than 20% should be justified with very high nonproductive time and/or problems of high severity that might have led to expensive fishing, sidetrack, or a new spud.

6.3. Benchmark Cost Development

6.3.1. Generation of costs multipliers

The benchmark cost is developed using the reference well, presented above. As earlier mentioned, multipliers are generated based on location, technical difficulties, organizational and geology differences between the reference well and the well of which the cost is being benchmarked. The benchmark cost is then estimated by multiplying the costs and performance parameters of the reference well by the generated multipliers.

As elaborated upon by Leamon (2006) and Kaiser and Pulsipher (2007), evaluation of drilling performance commands a high degree of visibility across oil and gas companies. They also pointed out that drilling rates are often constrained by factors that the driller does not control and in ways that cannot be documented. Kaiser (2009) further emphasized that understanding the drilling process requires isolating the factors of drilling and quantifying their interaction. He also recognized that the drilling objectives frequently conflict and depend on factors that interrelate; vary with respect to time, location, and personnel; and are subject to significant organizational and market uncertainty. In fact, it will be hard to identify all of the characteristics of drilling that might be important for cost estimation and benchmark. However, many characteristics can be observed. In practice it is usually sufficient to consider a set of factors that adequately represent operational, technical, location, organizational and market conditions.

In the framework of this cost benchmark platform, characteristics considered are grouped under following categories that contain important cost drivers and factors.

- Well program
- Testing and Coring
- Rig Information
- Problems and Complexity
- Drilling performance
- Well location
- Miscellaneous

Multipliers are generated under these categories and are then used for benchmark costs estimation. The next paragraphs shortly describe those categories and explain how the multipliers are generated.

6.3.1.1. Well program

Well program section contains information related to well diameter, casings, drilling fluids and cements. Multipliers are generated by: (i) assigning values 1.0 and 2.0 (based on data analysis, experience, and Experimental Design); (ii) where applicable, using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are calculated as presented in table 5 below.

Table 5: multipliers of well program section

Item	Multipliers
Casing	$\frac{Number\ of\ casing\ strings\ of\ well - number\ of casing\ strings\ reference\ well}{Number\ of\ casing\ strings\ of\ reference\ well} + 1$
Well Diameter	$\frac{Diameter\ of\ well - Diameter\ of\ reference\ well}{Diameter\ of\ reference\ well} + 1$
Drilling fluid	
Water based	1.0
Oil based	1.25
Synthetic	1.5
Extreme	2.0
Average DF	Sum drilling fluid multipliers/number of drilling fluid
Logging & Probes	
wireline	1.0
LWD	1.2
MWD	1.2
Probes	
Express	0.8
Standard	1.0
Tripple Combo	1.25
Quad Combo	1.25
Av. Loging & Probe	$\frac{Logging + probe}{2}$
Multiplier	$\boldsymbol{Casing * 40\% + Diameter * 10\%\ \ Ave. Drilling\ fluid * 30\% + Ave. Logging * 20\%}$

6.3.1.2. Coring and Testing

Coring and Testing section contains information related to number of cores, test types and duration. Multipliers are generated by using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are estimated as presented in table 6 below.

Table 6: multipliers of coring and completion & testing section

Item	Multipliers
Coring	$\frac{Number\ of\ days\ to\ core\ of\ well - Number\ of\ days\ to\ core\ reference\ well}{Number\ of\ days\ to\ cores\ of\ reference\ well} + 1$
Testing	$\frac{Test\ duration\ of\ well - Test\ duration\ of\ reference\ well}{Test\ duration\ of\ reference\ well} + 1$
Multiplier	$\boldsymbol{Coring} * \mathbf{50\%} + \boldsymbol{Testing} * \mathbf{50\%}$

6.3.1.3. Rig Information

Rig information section contains information related to rig contract (day rate and drilling time and contract type). Multipliers are generated by using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are estimated as presented in table 7 below.

Table 7: multipliers of Rig Information section

Item	Multiplier
Day rate	$\frac{Day\ rate\ of\ well - Day\ rate\ of\ reference\ well}{Day\ rate\ of\ reference\ well} + 1$
Rig contract time	$\frac{contract\ time\ of\ well - contract\ time\ of\ reference\ well}{contract\ time\ of\ reference\ well} + 1$
Contract type	
Turnkey	0.85
Day rate	0.95
Mix	0.90
Rig build status	
Old build	1.0
New build	1.25
Multiplier	$\boldsymbol{Day\ rate} * \boldsymbol{contract\ time} * \boldsymbol{contract\ type} * \boldsymbol{Rig\ build\ status}$

Where,

Contract time = days mobilizing + drilling days + WoW + Non-productive time + days demobilizing.

6.3.1.4. Problems and Complexity

Problems and complexity section contains information related to well complexity and problems encountered during the drilling process. Multipliers account for extended reach ratio, non-productive time, etc. Multipliers are generated by: (i) assigning values 1.0 and 2.0 (based on data analysis, experience, and Experimental Design); (ii) where applicable, using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are estimated as presented in table 8 below.

Table 8: multipliers of problems and complexity section

Item	Multipliers
Extended Reach Ratio (ERR)	$\frac{Extended\ Reach\ Ratio\ of\ well - Extended\ Reach\ Ratio\ of\ reference\ well}{Extended\ Reach\ Ratio\ of\ reference\ well} + 1$
Waiting on Weather (WOW)	$\frac{Waiting\ on\ Weather\ of\ well - Waiting\ on\ Weather\ of\ reference\ well}{Waiting\ on\ Weather\ of\ reference\ well} + 1$
Non-productive Time (NPT)	$\frac{Non\ Productive\ Time\ of\ well - Non\ Productive\ time\ reference\ well}{Non\ Productive\ Time\ of\ reference\ well} + 1$
Depth Ratio	$\frac{Total\ depth\ of\ well - Total\ depth\ of\ reference\ well}{Total\ depth\ of\ reference\ well} + 1$
HTHP	1.25
Problem Severity (PS)	
Sidetrack	1.5
New Spud	2.0
Fishing	1.25
None	1.0
Multiplier	$(\boldsymbol{ERR} * 20\% + \boldsymbol{WOW} * 20\% + \boldsymbol{NPT} * 30\% * \boldsymbol{HPHT} * 10\% + \boldsymbol{DR} * 20\%) * \boldsymbol{PS}$

6.3.1.5. Drilling Performance

Drilling performance section contains information related to the performance of the drilling process. It compares parameters such as Rate of Penetration, Organizational capabilities of operators and contractors, effectiveness of regulators' actions, etc. Multipliers are generated by: (i) assigning values 1.0 and 2.0 (based on data analysis, experience, and Experimental Design); (ii) where applicable, using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are estimated as presented in table 9 below.

Table 9: multipliers of Drilling Performance section

Item	Multipliers
Rate of Penetration (ROP)	$\frac{Average\ ROP\ of\ well - Average\ ROP\ of\ reference\ well}{Average\ ROP\ of\ reference\ well} + 1$
Operators' capability and experience (OPCE)	
Capability	
Small Independent	1.5
Medium Independent	1.25
Major	1.0
Experience with the basin	
Experienced	1.0
Not experienced	2.0
Average OPCE	(Capability + experience) /2
Drilling contractors Capability and experience(DCE)	
Capability	
Small and/or new	1.5
Medium and/or known	1.25
Large and/or well known	1.0
Experience with the basin	
Experienced	1.0
Not Experienced	2.0
Average DCE	(Capability + experience) /2
Regulators efficiency/ business climate (REB)	
Poor	1.5
Fair	1.25
Good	1.0
Multiplier	$\boldsymbol{(ave.OPCE * 40\% + ave.DCE * 30\% + REB * 30\%)/ROP}$

6.3.1.6. Well Location

Well location section contains information related to the location of the well such as physical location (country, onshore/offshore, etc.) and information related to the economy and the maturity of oil industry in the country or region where the well is located. Multipliers are generated by: (i) assigning values 1.0 and 4.0 (based on data analysis, experience, and Experimental Design); (ii) where applicable, using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that of the reference well. The multipliers are estimated as presented in table 10 below.

Table 10: multipliers of location section

Item	Multipliers
Distance to shore (DTS)	Onshore = 0 Offshore $\frac{Distance\ to\ shore\ of\ well\ in\ km}{10} + 1$
Water Depth (WD)	
Offshore shallow water	1.0
Offshore Deep water	2.0
Offshore ultra-deep water	3.0
Maturity of Industry (MI)	
Non producer	1.5
New producer (1-10 years)	1.25
Mature producer > 10 years	1.0
Economic development	
Low	1.5
Medium	1.25
High	1.0
Local Content Level (LCL)	
Low	2.0
Mean	1.5
High	1.0
Remoteness to existing Oil & Gas infrastructure (REM)	
No remote	1.0
Fairly remote	1.5
Very remote	2.0
Political/social stability (PSS)	
Low	2.0
Fair	1.5
High	1.0
Onshore multiplier	$(MI * 30\% + ED * 20\% + LCL * 25\% + PSS * 25\%)$ + **(Rem-1)**
Offshore multiplier	$(DTS * 20\% + WD * 80\%) + (MI * 30\% + ED * 20\% + LCL * 25\% + PSS * 25\%)$ + **(Rem-1)**

6.3.1.7. Miscellaneous

The miscellaneous section contains information related to oil price indexation. Inflation has not been considered because it does not play a major role in pricing and oil & gas market dynamics. The dynamics is more influenced by escalation, which is closely tied to achievable oil prices. Multipliers are obtained by using the ratio of the difference of the parameter of the well to benchmark and that of the reference well to that same parameter of the reference well. The multipliers are estimated as presented in table 11 below. OPI is the raw index and OPIM is the multiplier accounting for the price index. The rationale behind it is that 100% change in oil price will not definitely lead to 100% change in well cost items. It is most likely that 100% change in oil price will most likely lead to around 50% to 60% change in rig contract costs and 25%-40% change in other items' costs. Rig daily rates are strongly tied to demand-supply dynamics and other costs may also increase with increase rig daily rates.

Table 11: multipliers of miscellaneous section

Item	Multipliers
Oil Price indexation (OPI)	$\frac{past\ 12\ months\ ave.brent\ price\ \ year\ of\ well - Past\ 12\ monts\ ave.brent\ price\ year\ of\ reference\ wel}{Past\ 12\ months\ average\ brent\ price\ year\ of\ reference\ well}$ $+ 1$
OPIM offshore	If OPI < 1 OPIM = OPI +((1-OPI) *0.5*0.6) +((1-OPI) *0.25*0.4) If OPI >1 OPIM = OPI -((OPI-1) *0.5*0.6) +((OPI-1) *0.25*0.4) If OPI =0 OPIM=1
OPIM onshore	If OPI < 1 OPIM = OPI +((1-OPI) *0.5*0.4) +((1-OPI) *0.25*0.6) If OPI >1 OPIM = OPI -((OPI-1) *0.5*0.4) +((OPI-1) *0.25*0.6) If OPI =0 OPIM=1
Multiplier	**OPIM**

6.3.1.8. The overall Multipliers

The overall multiplier is calculated depending on the location, whether it is onshore or offshore. This relates to the average contributions of each cost category in both locations. To recall, rig rental has a much higher contribution offshore than onshore (around 50%), whereas sites surveys, ROW and constructions have a higher contribution onshore than offshore (around 20%). In this respect overall multipliers have been calculated as shown in table 12 below.

Table 12: formulae for the Overall Multipliers

Item	Multipliers
Onshore	(((average well program +average coring and testing)*30%) (average rig information *40%) + ((average problem and complexity +average well location+ average drilling performance)*30%)))*OPIM
Offshore	(((average well program +average coring and testing)*20%) (average rig information *60%) + ((average problem and complexity + average well location + average drilling performance)*20%)))*OPIM

6.3.2. Cost benchmark procedure

Two benchmark procedures are considered: (i) quick benchmark and (ii) detailed benchmark. Quick benchmark is a fast and simple procedure that makes use of the regional costs data table and Oil Price Index to create a benchmark cost that compares with booked cost/unit depth and total cost. The procedure is elaborated in the section dedicated to quick benchmark below. The next sections deal with detailed benchmark procedure.

6.3.2.1. Detailed Benchmark

Detailed benchmark generates benchmark costs for the different cost categories in the costs table, including cost/unit depth and total cost. The benchmark costs are compared with the costs of the well to benchmark. The differences are reported in terms of values and percentages.

It also enables comparison of costs contribution by categories and verify that they fall within the contribution ranges of each cost category observed in the industry. Table 13 below summarizes the calculation of the detailed benchmark costs onshore and offshore respectively. The calculations emphasize the contribution of contract time, daily rig rates and location on the costs.

Table 13: formulae for detailed benchmark parameters

Item	Benchmark Cost
Predrill and planning	((predrill and planning reference well * ((well program*50% + performance *20%+ location*30%)) * Oil Price Index Multiplier
Construction/site preparation	Construction/site prep. reference well *(location*50% + drilling performance *50%))* Oil Price Index Multiplier* Rig build status
Services and supplies	services and supplies reference well *((Rig contract time*40% +problems and complexity*30% + well location *30%) + ((Day rate-1)*25%))) * Oil Price Index Multiplier
Rig Contract	Rig contracts reference well * (rig information * (Maturity of industry*20% + Local content Level*30% + Economic Development*20% + Political stability*30%)) * Oil Price Index Multiplier
Casing and cementing	casing and cementing reference well * (Depth Ratio*0.75+ ((Dayrate-1)*25%))* (problems and complexity *35% + Drilling performance*35% + location*30%) * Oil Price Index Multiplier*Rig build status

Item	Benchmark Cost
Completion & Testing	Completion & Testing reference well *(testing) * (drilling performance*35% + problems and complexity*35% + location*30%)+ ((Dayrate-1)*25%)) * Oil Price Index Multiplier * Rig build status
Rentals	Rentals reference well * (Rig contract time+((Dayrate-1)*25%)) * (Problems and complexity *40% + location*30% + Drilling performance*30%)) * Oil Price Index Multiplier
Supervision and administration	supervision and administration reference well * ((Rig contract time*40% + location*30% + drilling performance*30%) +((Dayrate-1)*25%)) * Oil Price Index Multiplier * Rig build status
Total cost	Sum of Item costs
Cost per unit depth	Total cost / Total Depth

6.3.2.2. Quick Benchmark

Benchmark is performed by using the regional costs data. In this case a regional costs data table created and populated in the database will provide marker costs in terms of total costs and cost/ft or cost/m of well drilled in the region. The benchmark uses the Oil Price Index Multiplier presented in table 10 above, to adjust regional costs data read from data table. The data table includes minimum and maximum costs/depth.

Table 14 below presents information found in the data table. Then the costs will be used to multiply by the total depth of the well to obtain the minimum and maximum costs and compare with the reported costs. It requires accurate cost information to populate the database with.

This is a quick procedure, which should be used when detailed and categorized costs data is not available or data is insufficient to create those.

Table 14: example of information found in regional cost data table

Region	Basin	Onshore/offshore	Water depth (if offshore)	Year	Average Brent price	Cost/ft or Cost/m	
					US$	minimum	maximum
West africa	Niger Delta	Offshore	Shallow water	2015	50	4000	7000
West Africa	Rio del Rey	Offshore	Shallow waters	2014	80	4500	8000
North Africa	Gulf of Suez	onshore	N/A	2013	90	1500	2500
Caribbean	n/A	Offshore	Deep waters	2009	100	10000	15000

It is a very useful tool for high level benchmark. It helps to quickly verify that booked or AFE costs fall within the costs interval of a particular region and/or a particular basin. The deviations from minimum and maximum regional costs can be analysed using information on cost drivers and costs factors as described above. The costs can be analysed in relationship with country specificities, operator specificities and drilling problems primarily. Though a very useful tool, its disadvantage is that it does not allow to analyse contribution of each cost category to the total costs to see the plausibility of the reported data. It also relies on costs from the data table, which hides peculiarities of individual well and may have been built from costs published by operators or commercial data vendors, of which accuracy may sometimes be questionable, as has been also recognized by Leamon (2006).

It also requires an elaborate table of regional costs with all regions and basins names correctly entered as they are used as search keys for benchmark procedure.

7. Outlook for improvements and updating the platform

The cost benchmark platform is extensible and scalable and is built with state of the art open source web development technologies with PHP programming language and database application MySQL.

The quality of the analysis is determined by the amount and accuracy of data entered in the database. In the beginning the database is populated with only few and sparse data obtained from various sources listed in table 3 (for both detailed costs data and regional costs data in regional data table). In this circumstance, benchmarking based on reference well is very useful. It needs only data from well of which costs is going to be benchmarked. This data is entered by the user at various detail levels.

As time goes by, users will enter more and more data in the platform, to the point that the data sets will become qualified for predictive analytics. This data may be analysed with data mining techniques to generate models that may serve as predictors of costs data and be constantly updated using Artificial Intelligence (AI) techniques.

The next steps are:

- Acquiring and hosting the application in a secure cloud hosting platform;
- Populating the database with costs from end-users;
- Populating the data base with costs data from operators, NOC and commercial platforms where applicable;
- Extending the database with predrill exploration cost benchmark module including geological and geophysical surveys
- Update the platform continuously with feedback from users
- Eventual include a geological and seismic surveys module
- Integrating a data mining and AI module developed with Python or R languages and technologies that will generate and update predictive models in the platform.

8. How to use the platform

Refer to user guide manual

9. References

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