Drilling Costs Estimation for Hydrocarbon Wells

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Abstract: Worldwide drilling activities are significantly raised by the oil industry due to the increased global demand of hydrocarbon. The addition of new and sophisticated equipment, tools, and technologies in drilling a well are adding more costs in terms of new technology and equipment. In contrast, the reduction of drilling time due to the addition of those facilities has significantly reduced the drilling costs. As a result, there is a cost analysis dilemma faced by the drilling industry. In addition, shale gas wells are drilled using drilling technology very similar to that used in the drilling of conventional hydrocarbon wells. This causes the drill bit to wear out which significantly reduces the net penetration rate with the longer trip time. This scenario causes new challenges for the estimation of shale drilling cost in general. The overall cost estimation and analysis creates new challenges and responsibilities for the industry people. Moreover, cost effective drilling is one of the focal points for the industry toward a successful and sustainable drilling because by definition, sustainability covers the parameter, cost. The lack of proper training in handling financial sustainability has caused tremendous frustration in the current energy management sector. While everyone seems to have a solution, it is increasingly becoming clear that these options are not moving our drilling environment to any sustainable state.

This article evaluates current and historical drilling and completion costs of oil and gas wells. As a starting point, the general cost analysis concepts are discussed in detail to have a strong foundation on the drilling cost and time estimation. Field data are used to show the cost trends for various depths in calculating drilling cost and drilling time estimation. Also outlined is the significance of Authorization for Expenditure (AFE) in terms of variations of oil and gas prices, costs, and availability of major well components and services at particular locations. The new addition of some features in cost estimation will help in understanding the overall cost estimation. This article will enhance understanding of drilling cost analysis and will provide a guideline in preparing AFE.

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1 Introduction

Drilling is a complex and multidimensional activity. For the search or production of oil and gas, it is subject to significant sources of variability. Even though the physics of drilling is the same globally, there are numerous factors that can influence a wider range in drilling costs and performance. Total drilling cost is a value concept that places its' emphasis on the cost of drill productivity. According to Cunha (2002), drilling costs may represent up to 40% of the entire exploration and development costs. These costs represent 25% of the total oilfield exploitation cost mostly in exploration and development of well drilling (Khodja et al., 2010). Primarily drilling costs depend on well location and well depth. However, it is also a function of manpower skills, and experience; operator, contractor, and service company's experience; geologic conditions; availability of drilling rigs and associated equipment; casing, cementing, offshore or on shore locations; equipment efficiency; well specification; and numerous other factors. Based on market and/or economic environment, drilling costs can significantly vary. In addition, the supply and demand of the above technological supports and equipment availability may also influence the costs. Finally, there are many other elements contained in the drilling cost.

If we consider the total well costs, there is a need to calculate the impacts and end of life issues associated with wells, drilling, etc., mentioned as part of the "total" well cost. This paper thus, appears to focus solely on the initial "drilling costs" of a well, what it takes to sink the thing in the first place, and does not at all address the full life cycle of a well. Costs which are not part of this analysis include long term casing, cement, and operational costs; P&A costs, and even longer term concerns with wellbore leakage in association with increasing EOR; and geothermal and other underground injection scenarios which require good wellbore seal/integrity to ensure safe and economic operations in areas with existing older wellbore infrastructure. Although the cost estimation is an essential part of well planning, it is often the most difficult to obtain with any degree of reliability. Therefore, over the past several decades, various methods have been proposed to evaluate drilling cost and complexity. All these issues are addressed by Hossain and Al-Majed (2015).

Well drilling costs analysis is needed to prepare to get the necessary authority for expenditures during the drilling phase. A systematic drilling cost analysis is done which reflects the different approximate itemised costs, guidelines for costs, and information about the drilling project. In addition there are several reasons for producing a well cost which includes budgetary control, economics, partners recharging, and shareholders. The *Authorisation for Expenditure* (AFE) is then used as a document for partners recharging, paying contractors and overall control on the well spending. This article discusses the factors affecting the drilling costs,

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types of costs, and variables. However, the paper is not a full life cycle cost analysis of wells, but in fact, focuses on the cost of sinking a well for its initial intended use only. There is a small section where sustainable concepts based on environmental, social and economic aspects are highlighted to show the limitations of AFE.

2 Variables Related to Drilling Costs

It is recognized that there are many factors affecting onshore or offshore well costs which must be taken into consideration to accurately estimate the cost of a specific well. There are some common and uncommon factors that influence the well drilling costs. As a result, drilling costs increase non-linearly with depth (Figure 1a and 1b). The correlation in Figure 1 provides a good basis for estimating drilling costs based on the depth of a completed well alone. The major factors controlling the costs of drilling wells are the abnormal rig market conditions, well depth, diameter, casing design, well type (i.e. exploratory, development etc.), and well location (i.e. onshore, offshore, and geographic proximity to infrastructure and resources). In addition, there are many other secondary factors that affect the drilling cost. For example, the total depth of the well, type of rock formation, hole diameter, casing program, and the remoteness of the drilling site are few of the variables. Some of these factors are very important because they can significantly affect other drilling variables. For example, casing program is dependent on the hole depth that must be used to give the desired bottom hole diameter. The well type generally determines the type of rock formation, and to some extent, the lithology, that will be encountered. The well location can determine the rotary rig type (i.e. onshore or offshore) and material costs. Rig availability is dependent on rental rate, and partially on the ability to salvage parts from older rigs to keep working rigs operational. The differences in geology, hole diameter, well control, fluid chemistry, site accessibility and weather can cause very large variations in well costs for the same depth. This is much more apparent when drilling is being done in geothermal resources. All areas in subsurface have geothermal components when drilling is targeting a geothermal resource. They vary in wellbore diameter, completion, geology, fluid chemistry and accessibility.

Drilling costs for a hydrocarbon well can be subdivided into five origins:

i. Pre-spud costs
ii. Casing and cementing
iii. Drilling – rotating costs
iv. Drilling – non-rotating costs, and
v. Trouble costs.

Pre-spud cost includes move-in and move-out costs, site preparation and well design. This cost is related to the rig size, which is a function of hole diameter, length of the longest casing string and the depth of the hole (Hossain and

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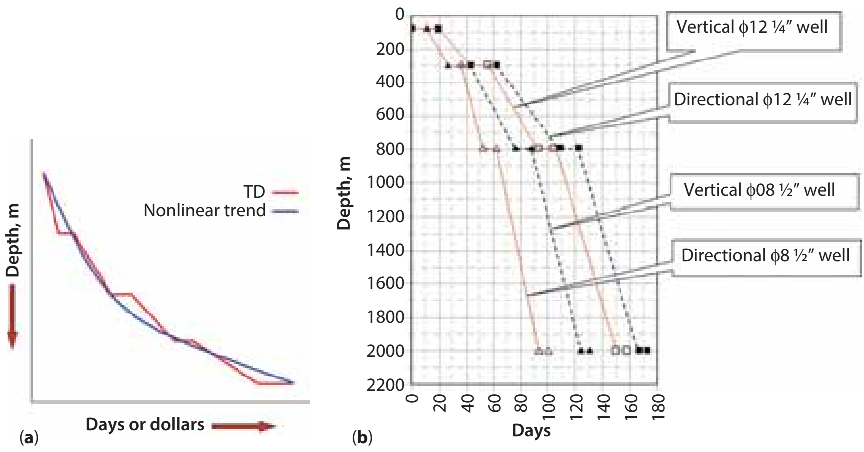

Figure 1 Drilling cost as a function of well depth (Hossain and Al-Majed, 2015)

Al-Majed, 2015). Casing and cementing includes the cost of casing and cementing materials as well as running casing and cementing in place. This cost depends on the depth and diameter of the hole as well as the fluid pressures and to some extent the geology encountered during drilling. While drilling, rotating costs are incurred when the bit is in rotation, including all costs related to the rate of penetration such as bits and mud costs. During drilling operation, non-rotating costs are those costs incurred when the bit is not in rotation and include tripping, well control, waiting, directional control, supervision and well evaluation. Costs for trouble during drilling that cannot be planned ahead include stuck pipe, twist offs, fishing, lost circulation, hole stability problems, well control problems, cementing and casing problems and directional problems. The trouble costs and rotating costs are directly related to the geology of the site, the depth of the well and, to a lesser degree, the well diameter. Non-rotating costs depend on depth and geology because it affects bit life and therefore tripping time.

The effect of inflation on drilling costs is also a great factor in terms of a country's financial stability, which is often used to adjust costs from year to year due to the effect on the gross domestic product (GDP) growth. GDP is a measure of the economic production which takes place within the geographical boundaries of a country. It can be measured at basic prices (by industry) or at market prices in constant year dollars. For example, Alberta is one of the oil producing zones in the world.

Alberta's economy expanded by 4.1% in 2013 (Economic Dashboard, 2014). Much of Alberta's strong economic performance was either directly or indirectly tied to its large and expanding oil and gas sector. Due to the oil production, Alberta's largest sector, mining and oil and gas, grew by 3.7%. Alberta's 3.8% GDP growth in 2013 was third highest in the country, behind Newfoundland and Labrador's 7.3% growth and Saskatchewan's 5.0% growth (Economic Dashboard, 2014).

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Differences between indices are driven by fluctuations in crude oil prices, which in turn drive the rig availability. They are also directly related to the inherent non-linear nature of well cost which increases with depth. Research results show that costs related to ROP, and casing and cementing costs are the most significant factors in drilling costs. These costs grow more significantly with well depth. Moreover the cost of adding extra casing strings to a well design have a very strong influence on drilling costs. An extra casing string cause a stepwise increase in the drilling cost of about 18% - 24% between two wells of the same depth. Finally, time is one of the most important variables influencing the drilling costs because some of the costs are time-dependent.

3 Types of Well Drilling Costs

In general, the cost can be defined as the expenses directly incurred by the driller (such as equipment, labour, materials, consumables, loan repayments, taxes, office overheads, and legitimate and other transaction costs). Drilling costs by definition consist of all resources required to be in place to make a hole for hydrocarbon production. These include capital costs, fixed cost, and variable cost in drilling a well. Capital costs include the investment in planning, preparing, construction, purchase of hardware etc. Fixed costs are classified into well-dependent and well-independent costs. Well dependent fixed costs include items such as the cost of casing, wellheads, and mobilization/demobilization. Well-independent fixed costs include, but are not limited to, administration, office services, insurance, legal support, interest charges on the money tied up in the equipment, expenses associated with maintaining and storing the equipment, etc. Further, fixed costs are the assembly of drill string and installation of safety valves. Variable costs are decomposed into time-dependent costs, such as the drilling rig day rate, tool charges, rentals, fuel, power and time-independent cost elements, such as running and cementing casings, materials, drill bits, and other consumables and services. The costing method must be robust and it will need to provide reliable estimates.

For this analysis, the total drilling costs include everything it takes to run a drill sting. It includes labour, power, fuel or electricity, drilling tools and supplies, maintenance labour and parts, supervision, administration, and cost of equipment ownership (lease, purchase, or rental payments). However, well drilling costs can be subdivided into the three main elements. No matter what service or product is used, it will fall under one of the following four cost elements: i) rig costs, ii) tangible costs, iii) intangible costs, and iv) service costs.

3.1 Rig Costs

Rig costs refer to the cost of hiring the drilling rig and its associated equipment. This cost can be up to 70% of well cost specifically for semi-submersible rigs or

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drilling ships. Rig cost depends entirely on the rig rate per day which is usually expressed as $/day. Rig rate depends on i) type of rig, ii) days on well, iii) mobilisation/demobilisation of rig and equipment, iv) market conditions, v) length of contract, vi) supervision, and additional rig charges.

3.2 *Tangible Costs*

Tangible costs refer to the products used on the well. These costs include i) casing, ii) tubing and completion equipment, iii) wellhead accessories, iv) bits, v) core heads, vi) cementing jobs and cement products, vii) mud products, viii) solids control consumables, ix) fuel and lubes, and x) other materials and supplies. The tangible costs should be looked at as each individual element that is responsible for costing of that item. For example, the costing of casing should begin by selecting the appropriate casing seats (i.e. length of casing) and selecting the appropriate casing grades/weights for each hole section. Then each casing string for each hole size should be utilized for costing. Finally the total costs of all the casing strings are added to produce the total casing costs for the well. The same method applies to each tangible items which require design, selection and breaking into individual groups. Further examples can be set for tubing and completion equipment, drill bits, core heads, and wellhead equipment.

3.3 *Intangible Costs*

Intangible drilling costs (IDCs) are defined as the expenses incurred during the exploration for gas, oil, or geothermal reserves that can be expensed in the year they have been incurred. In short, it can be represented as the costs to develop an oil or gas well for the elements that are not a part of the final operating well. IDCs include all expenses made by an operator, incidental, however, necessary in the drilling and preparation of wells for the production of oil and gas. Examples of IDCs include survey work, site preparation, employee wages, ground clearing, drainage, fuel costs, repairs, supplies and so on. Broadly speaking, the expenditures that have no salvage value are classified as IDCs. Since IDCs include all real and actual expenses except for the drilling equipment, the word "intangible" is something of a misnomer.

IDCs may be expensed in the year incurred, or they may be capitalized and deducted over a period of several years. It can be an effective tax reduction strategy when used to offset a company's income in one year although they were spent to develop or produce energy reserves and capital assets that will bring in income for many years to come. Intangible drilling costs are an effective means of reducing taxes because they can be used to offset income in a single year, even though the costs were incurred in order to produce or develop capital assets (energy reserves) that will in turn generate income for many years. The IDCs deduction has been allowed in the US since 1913 in order to attract investment capital to the high-risk

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business of oil and gas exploration. If a taxpayer makes an election to expense IDCs, the taxpayer deducts the amount of the IDCs in the taxable year in which it was paid or incurred.

3.4 Service Costs

The service costs refer to the expenditures associated with any service required on the well. The service costs include i) communications (i.e. refers to telephones, data transfer etc. which is a lump sum cost or cost per day) ii) rig positioning (i.e. the cost required to position the rig which is usually required in offshore operations), iii) wireline logging (i.e. the cost of running and producing wireline logs, both open hole and cased hole logs), iv) measurement while drilling (MWD)/ logging while drilling (LWD) (i.e. the cost of renting and running MWD, LWD), v) downhole motors (i.e. the cost of using downhole motors during directional drilling or during drilling long sections of vertical wells), vi) solids control equipment (i.e. the consumables required for solids control equipment and any special equipment the rig contractor does not normally provide), vii) mud engineering (i.e. the cost of the mud engineer and the services required to maintain the mud which is not the cost of mud products as explained earlier under tangible costs), viii) directional engineering (i.e. the cost of the directional engineer, software and support required during directional drilling), ix) surveying (i.e. the cost of running surveys inside the hole to determine hole angle and azimuth which usually includes the cost of single shots, magnetic multi-shots (MMS) and gyros plus the cost of the engineer and rental of the equipment to run the surveys), x) cementing (i.e. the cost of renting the cementing unit and the cement engineer), xi) mud logging (i.e. the cost of renting the mud logging unit and the engineers required to run the unit), xii) fishing (i.e. an ad-hoc cost of renting fishing equipment and cost of engineers which is only included if experience in the area dictates that fishing may be required in some parts of the hole and that fishing equipment must be available at the rig site to be used for such eventualities, xiii) downhole tools (i.e. any tool required which is not supplied by the drilling contractor, including jars, shock subs etc.), and xiv) casing services (i.e. the equipment required).

4 Breakdown of Total Well Drilling Cost

The total well drilling costs can be broken down as percent costs. Figures 2 and 3 show the cost breakdown in different situations. Figure 2 depicts the breakdown of total drilling costs into the three categories. The preparation of a site includes drilling pad, water supply, and surface casing etc., which carry 18% of the total costs. Drilling amounts to 73% of the total cost, which includes materials too. The other 9% is the completion after drilling including wellhead, silencer, and drainage system etc.

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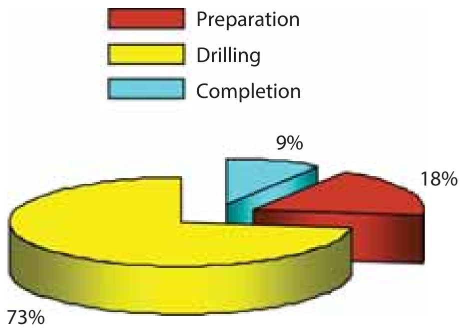

Figure 2 Breakdown of total drilling cost (Courtesy: VGK-Hönnun hf.)

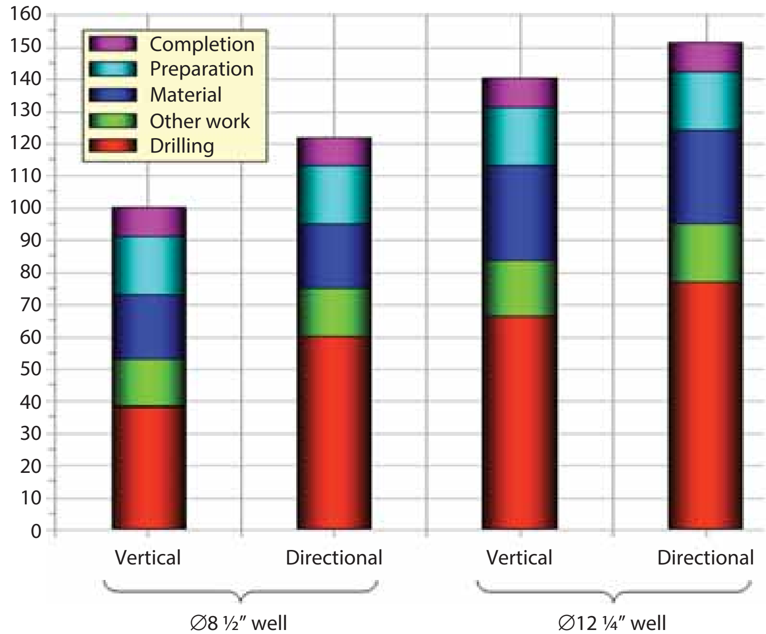

Figure 3 Total cost of drilling for different types of wells (Courtesy: VGK-Hönnun hf.)

Figure 3 shows the breakdown of the total cost of drilling different types of wells and sizes. For the four cases, drilling cost is the highest compared to other costs such as material, preparation, and completion. Vertical well is less costly than directional drilling.

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5 Authorization for Expenditure

Due to the huge financial involvement and high risk of having dry wells, the operator must prepare a spreadsheet which is called the AFE. An AFE is a detailed cost estimate or budget for the well. The AFE sheet also reflects project description, summary and phasing of expenditure, partner's shares and well cost breakdown. The total well cost, the time, and the cost for each major type of expense are listed in the AFE spreadsheet. Finally all of the costs and times are summed and transferred to the AFE sheet. The AFE sheet is chosen as the primary form of output because most available information is recorded in that format. Details of the well are attached to the AFE sheet as a form of technical justification. Preparing cost estimates for a well and getting management approval in the form of an AFE is the final step in well planning. Once the AFE is prepared, it should then be approved and signed by the authority before proceeding to drill a well. The AFE is often accompanied by a projected payout schedule or revenue forecast. Generally an AFE contains a provision for contingency costs. It is expected that operators will have the necessary expertise to predict well costs that will not exceed 20% of the initially predicted budget. In some cases, such as the evaluation of a given area of land available for lease, only an approximate cost estimate is required. In other cases, such as in a proposal for drilling a new well, a more detailed cost estimate is required.

If the accurate prediction of drilling cost is desirable, a well cost analysis based on a detailed plan must be undertaken. The cost of tangible well equipment (such as casing) and the cost of preparing the surface location usually can be predicted accurately. In addition, the drilling operations cost per day can be estimated from the rig rental costs, other equipment rentals, transportation costs, rig supervision costs, and other associated costs. The drilling engineer prepares AFE based on all gathered information. AFEs vary significantly in format and amount of information contained. Normally each company will have its own customized AFE form. An example of an AFE for an offshore well in the Gulf of Mexico is shown in Table 1 (Mitchell et al., 2012). However, an onshore AFE can also be prepared which is very much similar to Table 1, excluding some features. The provision of an extra percentage of the total predicted cost for "contingencies" is customary. This amount is set aside for costs related to unexpected drilling problems such as mud contaminations, lost circulation, stuck drillstring, broken drillstring, or ruptured casing. Moreover, geological uncertainties are always present, and eventually a well may end up being deeper than originally predicted, which will increase the final well cost. As experience is gained in an area, more-accurate predictions of drilling time can be obtained, and consequently better AFEs can be prepared.

Introduction to sustainable drilling can significantly reduce the drilling costs for long term investment. The drilling cost can be improved considerably by i) non-productive time (NPT), ii) invisible lost time (ILT), iii) feet/metres per day,

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Table 1 Example of an AFE for an offshore well in the Gulf of Mexico

						AFE No.:		
						Original#:		
Lease:			Well No.:			Supplement#:		
Field:			County: Offshore		State: Louisiana			
Proposed TD:			Objective:					
Legal Location:						Budget period:		
Code		DHC to drill well to 24,000′ md/tvd				Dry Hole Cost (BCP)	Completion Cost (ACP)	Total
BCP	ACP							
Estimated Intangible Drilling Cost								
		Surveys and permits				$0		$0
		Surface Damages						
		Location				$0		$0
		Location clean up	Rate	Days	Days			$0
		Rig move (mob & demob.)				$0		$0
		Drilling Cost – Turnkey						$0
		Drilling Cost – Day work	$219000	45		$9,855,000		$9,855,000
		Fuel/water (Rig/Boat)	$19,100	45		$859,500		$859,500
		Transportation (Boats/Air/Trucking)				$1,966,800		$1,966,800
		Rental tools (Equipment/Rental Repair)				$360,550		$360,550
		Bits				$226,880		$226,880

DOI: 10.7569/JSEE.2014.629520

		Drilling mud/chemicals/mud engineer		$2,742,050		$2,742,050
		Mud and sample logging		$201,150		$201,150
		Dir. Drilling service/tools/motors /surveys		$511,815		$511,815
		MWD/LWD/PWD		$447,000		$447,000
		Cement and cementing services		$668,500		$668,500
		Casing crews and tools		$450,000		$450,000
		Fishing operations		$50,000		$50,000
		Logging – open hole		$0		$0
		Completion rig cost		$0		$0
		Perforating, case hole logging TCP, CBL		$0		$0
		Acidizing and fracturing (frac pack)		$0		$0
		Sand control GP		$0		$0
		Testing, BHP surveys, etc.		$0		$0
		Completion fluid and filtering		$0		$0
		Contract labour		$1,500		$1,500
		Rig supervisor +drilling engr.+opers./geol.		$268,200		$268,200
		Dock/dispatcher/communication/catering		$248,085		$248,085
		P&A/T&A		$0		$0
		Pipe inspection		$130,000		$130,000
		Overhead		$547,870		$547,870
		Insurance/Taxes		$0		$0
		Misc. (disposal/boat cleaning/ROV/true training/others)		$892,950		$892,950
		Contingencies		$561,567		$561,567
		Total Intangibles		**$20,989,398**	**$0**	**$20,989,398**

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Table 1 Example of an AFE for an offshore well in the Gulf of Mexico (Continued)

Estimated Tangible Drilling Cost								
		Drive pipe	369	36	$200.00	$73,730		$73,730
		Conductor	3,545	20	$71.40	$253,120		$253,120
		Surface casing	3,030	16	$71.00	$215,130		$215,130
		Intermediate casing	10,353	13 5/8	$60.41	$625,395		$625,395
		Drilling Liner	0	9 5/8	$36.56	$0		$0
		Production liner					$0	$0
		Production casing						
		Production tubing					$0	$0
		Casing equipment/service/contingencies				$120,000		$120,000
		Wellhead Equipment/MLS Equipment				$660,000		$660,000
		Subsurface production equip. (Packers & SCSSV & GP)						$0
		Pumping unit and installation						$0
		Rods and downhole pump						$0
		Tank Batteries						$0
		Separators, heaters, dehydrator etc.						$0
		Flow lines, fittings and connections						$0
		Caisson and/or protective structure						$0
		Labour – Production equipment						$0
		Contingencies			$0	$2,000		$2,000
		Total Tangibles				$1,949,375	$0	$1,949,375
Total Drilling and Completion Costs						$22,938,773		$22,938,773
Percent Working Interest						100.00%	100.00%	100.00%
Total Working Interest Well Cost						**$22,938,773**		**$22,938,773**
Approved:								

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iv) flat time, v) rig moves, vi) realized value of "lessons learned", vii) cost under AFE, viii) time under AFE, ix) riser running speed, x) Blowout preventer (BOP) test times, and xi) more unknowns when sustainability is considered. Ultimately, the sustainable drilling costs influence the improvement of AFE. The purpose of the sustainable drilling is two-fold: 1) to reduce the environmental impact of drilling operations, and 2) to promote a reduction in the environmental impact of the entire industry. However, the solution involves collaborative partnerships with stakeholders and the industry as a whole. AFE can also be affected by the following parameters, which are directly related to sustainability.

Environmental value: Oil and gas operations have an impact on the environment because the oil industry is recognized as one of the hazardous industries (Hossain et al., 2014). Higher industry standards generate environmental improvements and a reduction of the overall impact caused by industry activities. Environmental value can be improved by reduced air pollution, which is accomplished by making engine combustion more efficient (Agbon, 2002). It can also be improved by the promotion of easier and cheaper access to energy-efficient technologies and by rethinking business models. However, in its present form, AFE offers no such option to include the environmental costs related to drilling.

Social value: The generation and development of new and innovative energy-efficient technologies creates jobs. A reduced output of toxic and harmful air emissions results in a healthier ecosystem that supports aqua and agriculture. Reduced toxic and harmful air emissions limits human health impacts

Economic value: The energy efficiency projects are expected to generate stronger business partnerships, which leads to economic value. Fuel cost savings from more energy-efficient combustion and better data management improve the economic value. Joint investment in the development of new technologies and pilot studies leads to savings.

6 Drilling Cost Estimation

The drilling cost formula is normally used in evaluating the efficiency of a bit run. Other applications include the recommendations concerning routine rig operations such as drilling fluid treatment, pump operation, bit selection, and any problems encountered during drilling operations. In addition, drilling optimization through comparison technique is based on criteria such as cost per foot, specific energy, and rate of penetration to optimize the drilling variables. Finally, preparation of drilling cost estimates may require as much engineering work as the actual well design. The cost estimate is heavily dependent on the technical aspects of the well to be drilled. In addition, offshore drilling costs are very high compared to onshore drilling because of abrupt change of environment, technology, and management (Jenkins and Crockford, 1975). Therefore, these aspects have to be established first.

DOI: 10.7569/JSEE.2014.629520

These aspects include the following:

1. *The type of wells*: the type of well to be drilled must be specified (i.e. exploration, appraisal, delineation, or development wells). In general, exploration and appraisal wells cost more because of extensive testing, coring, etc. Moreover, since exploration wells are drilled in wildcat or rank wildcat areas, the optimization of drilling parameters is difficult.
2. *The configuration of wells*: the configuration of wells to be drilled need to be clarified. It is important to know whether the configuration is vertical, deviated, horizontal, multilateral, a new well or sidetrack, and whether it is a water disposal well or injection well.
3. *The type of drilling contract to be used and the rig type*: Rig cost constitutes a major percentage of the total drilling cost. The onshore rig costs range from \$10,000 to \$15,000 per day while the offshore rig costs range from \$25,000 to \$100,000 per day. The rig costs in a particular area depend on the supply and demand of the rigs available, i.e. local drilling activity.
4. *The depth of the well*: the cost of well increases with depth. In general the cost is estimated as cost per foot.
5. *The complexity of the formations*: the formation complexity of a well influences how it is drilled. For example, the cost of drilling increases in high pressured, sloughing shale, unconsolidated formations, formations with thief zones, etc.
6. *Casing*: the casing scheme to be used and the type of casing required.
7. *Mud rheology*: the drilling muds rheology to be used.
8. *Bit type*: the type of bits to be used.
9. *Sampling and coring*: testing and coring requirements
10. *Well completion*: completion equipment, technique etc.

Once the technical aspects are established, the expected time required to drill the well is determined. A large fraction of the time required to complete a well is spent either drilling or making a trip to replace the bit. The total time required to drill a given depth can be expressed as the sum of the total rotating time during the bit run, the non-rotating time during the bit run, and the trip time. The actual well cost is then obtained by integrating the anticipated drilling and completion times with the well design. As is obvious from the daily rig costs given above, the time required to drill a well has a significant impact on many items in the well-cost estimate. These items may include the following – type of drilling contract; drilling rig; drilling fluid; offshore transportation (helicopter and marine); rental tools; and time-dependent support services.

The overall well cost excluding the production is calculated as

$$C_{owc} = C_f + C_o \tag{1}$$

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Here

C_{owc} = overall well cost excluding the production, \$/ft
C_f = drilling cost per unit depth, \$/ft
C_o = all other costs of making a foot of hole, such as casings, mud, cementing services, logging services, coring services, site preparation, fuel, transportation, completion, etc., \$

The drilling cost per foot for a bit is defined by the following formula:

$$C_f = \frac{C_b + C_r\left(t_d + t_c + t_t\right)}{\Delta D} \tag{2}$$

Here
C_b = bit cost, \$
C_r = rig cost or fixed operating cost of the rig per unit time, \$/hr
ΔD = formation interval drilled or drilled footage, ft
t_d = drilling time or rotating time during the bit run, hrs
t_c = connection time or non-rotating time during the bit run, hrs
t_t = trip time, hrs

Equation (2) has several assumptions such as i) it ignores risk factors associated with drilling operations, inflation rate, costs of environmental effects, and ii) the results of the cost analysis sometimes must be tempered with engineering judgement. Moreover, reducing the cost of a bit run will not necessarily result in lower well costs if the risk of encountering drilling problems such as stuck pipe, hole deviation, hole washout, etc. is increased greatly. There are worked-out examples that deal with the calculation of drilling costs (Hossain and Al-Majed, 2015).

Drilling costs tend to increase exponentially with depth. It is a good strategy for drilling engineers to be dependent on previous data to estimate drilling time and cost for future operations. When enough data are available for a certain region, curve-fitting drilling cost data can be generated. Thus, it is often convenient to assume a relationship between total well cost, C_{dc}, and depth, D, given by

$$C_{dc} = a_{dc} e^{b_{dc} D} \tag{3}$$

Here
C_{dc} = drilling cost, \$
a_{dc} = constant depend on well location, \$
b_{dc} = constant depend on well location, ft^{-1}
D = total depth, ft

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7 Well Drilling Time Estimation

The estimation of drilling and completion time is a dependent variable which is governed by different activities while drilling. An accurate estimate of the time is necessary to drill the well before preparing an AFE. Well drilling time is estimated based on the basis of rig-up and rig down time, drilling time, trip time, casing placement time, formation evaluation and borehole survey time, completion time, non-productive time, and trouble time. Drilling times include making the hole, which requires circulation, wiper trips and tripping, directional work, geological sidetrack and hole opening. Flat times are spent on running and cementing casing, and making up BOPS and wellheads. The well needs to be tested while drilling so it includes testing and completion time. The formation evaluation time includes coring, logging etc. Trouble time includes time spent on hole problems such as stuck pipe, well-control operations, and formation fracture. Major time expenditures always are required for drilling and tripping operations. In addition to predicting the time requirements for drilling and tripping operations, the time requirement for other planned drilling operations must be estimated. The additional drilling operations usually can be broken into the general categories of wellsite preparation, rig movement and rigging up, formation evaluation and borehole surveys, casing placement, and well completion, and drilling problems. So, the time estimate should consider i) initial placement, ii) Rate of penetration (ROP) in offset wells from where the total drilling time for each section may be determined, iii) flat times for running and cementing casing, iv) flat times for nippling up/down BOPs and nippling up wellheads, v) circulation times, and vi) BHA made-up times. However, all these factors are very much dependent on rig side people's experience, efficiency, and available resources. So well drilling time estimation is a challenge for the drilling engineer. A typical example of an actual time distribution for operations in a deep-water well in Gulf of Mexico is shown in Table 2 (Mitchell et al., 2012). The following example gives an idea of how a drilling time estimate is prepared.

Hossain and Al-Majed (2015) illustrated several examples that can help to understand the concept of calculation of the time. The drilling time can be estimated based on the data available on analogous wells in the same or similar area (Table 2). Numerous sources are available to enable estimating drilling time of a well (Hossain and Al-Majed, 2015). These include bit records, mud records, and operator's well histories on offset or analogous wells. The following several factors affect the amount of time spent in drilling a well. Each factor may vary with drilling geology, geographical location, and operator philosophy and efficiency.

1. *Drilling rate*: it depends on rock type, bit selection, mud type and properties, weight on bit, and rotary speeds.
2. *Trip time*: it depends on well depth, amount of mud trip margin, hole problems, rig capacity, and crew efficiency. As a rule of thumb, trip time is estimated as 1 hr/100 ft of well depth.

DOI: 10.7569/JSEE.2014.629520

Table 2 Time Distribution for Gulf of Mexico Deep-water Well

Operation Description	**Days**	**Percentage**
Normal operation (except drilling)	44.40	37
Drilling	34.80	29
Lost time – operation problems	14.40	12
Lost time – service company equipment	3.60	3
Lost time – rig equipment	3.60	3
Weather-related problems	9.60	8
Plugging and abandoning	3.60	3
Rig moving and positioning	6.00	5
Total	**120.00**	**100.00**

3. *Hole problems*: hole sloughing, lost circulation, and slower drilling rates are considered as standard hole problems.
4. *Running casing*: the time for running casing depends on casing size, depth of well, hole conditions, efficiency of crew, and use of special equipment.
5. *Measurement while drilling*: logging, coring, and pressure (DST, drawdown or buildup) surveys.
6. *Directional/Horizontal drilling*: the directional control of a well requires increases in the drilling time which ultimately increases the total well drilling time.
7. *Well completion*: it is dependent on the complexity of well completion (i.e. single completion, duel completion, commingled completion, gravel pack, acidizing, fracturing, and other forms of well treatments). The use of a completion rig versus drilling rig for completion operations should be considered where technically and economically feasible. A completion rig is a smaller workover rig that costs significantly less than a large drilling rig.

The well-cost estimate is usually divided into several cost categories for engineering and accounting purposes (i.e. dry hole versus completed well costs and tangible versus intangible costs). General summaries of typical well costs are given in AFE (Table 1).

7.1 Drilling Time Estimation

An estimation of drilling time can be based on historical ROP data where a drilling program will be set for the area of interest. For a given formation, ROP is inversely proportional to both compressive strength and shear strength of the rock. In addition, rock strength tends to increase with depth of burial. This is due to the higher

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confining pressure caused by the weight of the overburden. When major unconformities are not present in the subsurface lithology, the penetration rate usually decreases exponentially with depth. Under these conditions, ROP can be related to depth, D as:

$$\frac{dD}{dt} = K\,e^{-AD} \tag{4}$$

Here

$\frac{dD}{dt}$ = rate of penetration, ft/hr
K = constant, ft/hr
A = constant, ft^{-1}
D = total depth, ft

It is noted that constant A and K of Eq. (4) must be determined from the previous field data. Now, the drilling time can be obtained by integrating and solving the Eq. (4) for a given depth as:

$$K\int_0^{t_d} dt = \int_0^{D} e^{AD}\, dD \tag{5}$$

Equation (5) has a definite integral which can be solved for t_d and the final form of the equation becomes:

$$t_d = \frac{1}{AK}\left(e^{AD} - 1\right) \tag{6}$$

If there is available drilling data or previous experience exists in an area, more accurate predictions of drilling time can be attained by plotting depth vs. drilling time from past drilling operations (Figure 4). These types of plots are used in evaluating new drilling procedures designed to reduce drilling time to a given depth. Equation (6) allows more accurate prediction of time and cost for drilling a new well and is used in evaluating new drilling procedures (designed to reduce drilling time to a given depth).

Equation (4) can also be used to determine for a given bit, i, to drill from a depth of D_i to a depth of $D_{i+L,}$ which may be given as:

$$K\int_0^{t_{di}} dt = \int_{D_i}^{D_{i+L}} e^{AD}\, dD \tag{7}$$

DOI: 10.7569/JSEE.2014.629520

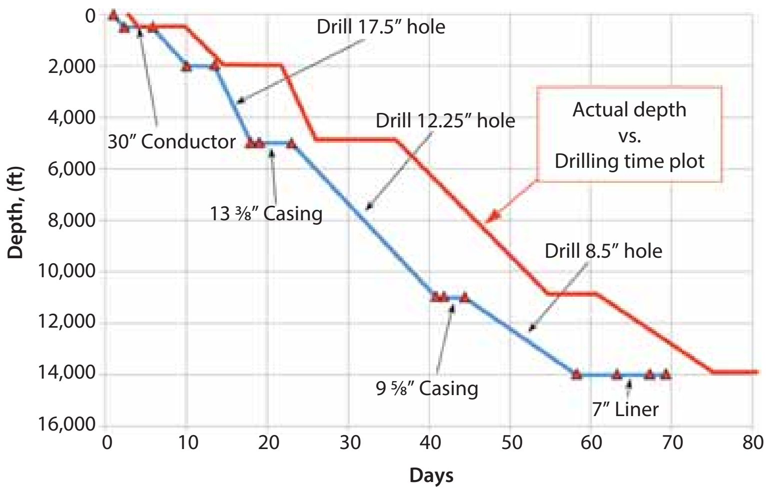

Figure 4 Theoretical and actual time verses depth curve showing different stages of drilling activities

Equation (11.7) can be solved for drilling time of a given bit, *i* as

$$t_{di} = \frac{1}{AK}\left(e^{AD_{i+L}} - e^{AD_i}\right) \tag{8}$$

Here

t_{di} = drilling time for a given bit *i*, hrs
D_i = depth of interest from where drilling time would be measured for a given bit, ft
D_{i+L} = depth of interest up to where drilling time would be measured for a given bit, ft

The drilling time required to drill from D to $(D + 1000)$ can be obtained using Eq. (6) as:

$$t_{d'} = \frac{1}{AK}\left[\left\{e^{A(D+1000)} - 1\right\} - \left\{e^{AD} - 1\right\}\right] \tag{9}$$

Here

$t_{d'}$ = drilling time required to drill from D to $(D + 1000)$, hr

DOI: 10.7569/JSEE.2014.629520

Equation (9) reduces to:

$$t_{d'} = \frac{e^{AD}}{AK}\left[e^{1000A} - 1\right] \tag{10}$$

7.2 Trip Time Estimation

In well drilling time estimation, a second major component of the time required to drill a well is the trip time which can be defined as the time required for changing a bit and resuming drilling operations. The time required for tripping operations depends primarily on the depth of the well, the rig being used, and the drilling practices followed. It can be approximated using the following relation as

$$t_t = 2\left(\frac{\overline{t_s}}{\overline{l_s}}\right)\overline{D_t} \tag{11}$$

Here

t_t = trip time required to change a bit and resume drilling operations, hrs
$\overline{t_s}$ = the average time required to handle one stand of drillstring, hrs
$\overline{l_s}$ = the average length of one stand of drillstring, ft
$\overline{D_t}$ = the mean depth where the trip was made (i.e. mean depth at the trip level), ft

It is noted that the time required to handle the drill collars is greater than for the rest of the drillstring, but this difference usually does not warrant the use of an additional term in Eq. (11). Historical data for the rig of interest are needed to determine, $\overline{t_s}$.

7.3 Number of Bit Estimation

Formation with high strength requires the use of a greater number of bits to drill a given depth interval. In some cases, the number of trips required to drill a well is greater than to treat each trip individually with convenience. Table 3 shows the bit records for a well drilled in the South China Sea (Bourgoyne et al., 1986). Mathematically, the number of bits required for a given depth can be expressed as:

$$N_b = \frac{t_d}{t_{bl}} \tag{12}$$

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Table 3 Bit Records for South China Sea Area

Bit No.	Depth out (ft)	Mean depth (ft)	Bit time (hrs)	Total drilling time (hrs)	Average ROP (ft/hr)	Hole size (in)
1	473	237	1.0	1.0	473	15.00
2	1,483	978	5.0	6.0	202	15.00
3	3,570	2,527	18.5	24.5	113	12.25
4	4,080	3,825	8.0	32.5	64	12.25
5	4,583	4,332	7.0	39.5	72	12.25
6	5,094	4,839	7.0	46.5	73	12.25
7	5,552	5,323	14.0	60.5	32	12.25
8	5,893	5,723	11.5	72.0	30	12.25
9	6,103	5,998	9.0	81.0	23	12.25
10	6,321	6,212	11.5	92.5	19	12.25
11	6,507	6,414	9.0	101.5	21	12.25
12	6,773	6,640	9.0	110.5	30	12.25
13	7,025	6,899	9.5	120.0	27	12.25
14	7,269	7,147	8.0	128.0	31	12.25
15	7,506	7,388	16.0	144.0	15	8.5
16	7,667	7,587	12.0	156.0	13	8.5
17	7,948	7,808	14.0	170.0	20	8.5
18	8,179	8,064	8.0	178.0	29	8.5
19	8,404	8,292	10.5	188.5	21	8.5
20	8,628	8,516	11.0	199.5	20	8.5
21	8,755	8,692	7.0	206.5	18	8.5
22	8,960	8,858	10.0	216.5	21	8.5
23	9,145	9,053	11.0	227.5	17	8.5

Here

N_b = numbers of bit, nos.

t_{bl} = average bit life for a particular depth, hrs

7.4 Connection Time Estimation

The third important time required for drilling operations is the connection time, which can be calculated as:

$$t_c = N_s \times \overline{t_s} \tag{13}$$

DOI: 10.7569/JSEE.2014.629520

Here

N_s = numbers of average stands of drillstring, nos.

The number of average stands of the drillstring can be calculated as the total drill length over the average length of one stand of the drillstring, i.e.

$$N_s = \frac{\bar{D}}{\bar{l}_s} \tag{14}$$

Here

$\bar{D}$ = mean depth of the well, ft

Total cost of the bit used for the planned well can be calculated as:

$$C_{Tb} = C_b \times N_b \tag{15}$$

Here

C_{Tb} = total cost of the bits used for the whole drilling operations, $

Total cost of the rig paid as rent for the whole drilling operation can be calculated as:

$$C_{Tr} = C_r \times t_d \tag{16}$$

Here

C_{Tr} = total cost of the rig paid as rent for the whole drilling operation, $

7.5 Coring Cost Estimation

While drilling, one of the objectives is to get the core sample for inspection. So, it is important to find out the coring cost per foot and the total coring time. Core recovery is given as the ratio length of the core recovered to the length of the core cut. It is usually expressed as a percentage. Similar to drilling costs, coring costs per foot can be given as:

$$C_{cf} = \left\{ \frac{C_{cb} + C_r \left(t_{ct} + t_{cr} + t_{cc} + t_{crl} + t_{co} \right)}{\Delta D_{ROP}} \right\} \frac{1}{R_c} \tag{17}$$

DOI: 10.7569/JSEE.2014.629520

Here

C_{cf} = coring costs per foot, \$/ft
C_{cb} = core bit cost, \$
t_{ct} = core trip time, hrs
t_{cr} = core rotating time, hrs
t_{cc} = core connection time, hrs
t_{crl} = core recovery, and laying down of core barrel time, hrs
t_{co} = coring time, hrs
R_c = core recovery factor, %
ΔD_{ROP} = the formation depth where the coring will be done (a function of rate of penetration), ft

ΔD_{ROP} can be calculated as:

$$\Delta D_{ROP} = \int_0^{t_{cr}} ROP\, dt \tag{18}$$

Here

ROP = rate of penetration, ft/hr

8 Time Value of Investment

The time value of money is the value of money figuring in a given amount of interest earned over a given amount of time. It is the growth potential of money over a period of time. The time value of money is the central concept in finance theory. The concept of interest is key to accounting for time value of money. To account for the time value of money, all future expenditures and revenues need to be converted to a common denominator, i.e., a common equivalent value of all the future cash flows is calculated at a common point in time. This common point may be the present, future, or even annual. The capital investment related to well drilling costs is directly influenced by time factor, inflation rate, political situation etc. Therefore time value of capital investment for drilling operations should be analyzed thoroughly.

8.1 Future Value Estimation

Future value is the value of an asset or cash at a specified date in the future that is equivalent in value to a specified sum today. The future value is determined as:

$$V_f = V_p \left(1 + \frac{i}{m}\right)^{n\,m} \tag{18}$$

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Here

V_f = future value, $

V_p = present value, $

i = nominal interest rate per year or growth rate in fraction, $

m = number of interest compounding per year or the number of payments per year, nos.

n = number of years, nos.

For the case of continuous compounding, which is commonly used within the petroleum producing industry, the relationship between the present and the future values becomes:

$$V_f = V_p \left(e^{i\,n}\right) \tag{19}$$

The present value of a future payment is the core for the time value of money. The mathematical relationships for the other formulas are derived from this concept. For example, the annuity formula is the sum of a series of present value calculations. The present value formula can be written as:

$$V_p = V_f \left(1+i\right)^{-m} \tag{20}$$

The expected value is calculated as

$$V_{ex} = \sum_{j}^{k} P_j C_j \tag{21}$$

Here

V_{ex} = expected value, $

P_j = provability of the jth event

C_j = cost of the jth event, $

9 Price Elasticity

Price elasticity is used to measure the effect of economic variables such as demand or supply of rigs or wells drilled with respect to change in the crude oil price. It enables one to find out how sensitive one variable is with the other one, and it is also independent of units of measurement. It is the ratio of the percentage of the change of wells and footage drilled to the percentage change in the crude price. It

DOI: 10.7569/JSEE.2014.629520

describes the degree of responsiveness of the rig in demand or rig in supply to the change in the crude price. So drilling price elasticity can be obtained as

$$E_d = \frac{R}{P_{oil}} \tag{22}$$

Here

E_d = drilling price elasticity
R = percentage change in drilling wells
P_{oil} = percentage change in the crude price

In order to compare the calculated elastic values, the elasticity can be classified as follows:

1. Inelastic: Elasticity is less than one. The number of drilling rigs does not respond strongly to the oil price.
2. Elastic: Elasticity is greater than one. The number of drilling rigs responds strongly to the oil price.
3. Perfectly Inelastic: Elasticity is equal to zero. The number of drilling rigs does not respond to the oil price change.
4. Perfectly Elastic: Elasticity is equal to infinity. The number of drilling rigs responds infinitely to the oil price change.
5. Unit Elastic: Elasticity is equal to one. The number of drilling rigs responds by the same percentage as the oil price change.

10 Current Trend on Drilling Cost Analysis

The objective of drilling a hydrocarbon well is to make a hole as quickly as possible subject to the technological, operational, quality, and safety constraints associated with the process. These objectives are frequently conflicting and depend on factors that interrelate and vary with respect to time, location, and personnel, and are subject to significant intrinsic and market uncertainty. Drilling rates are often constrained by factors that the driller does not control and in ways that cannot be documented. In many situations, the causes of dysfunction are complex, occur simultaneously, and lack effective solutions.

The evaluation of drilling performance commands a high degree of visibility in oil and gas companies, and over the past few decades, various methods have been proposed to evaluate drilling cost and complexity. To understand the drilling process, it is necessary to isolate the factors affecting drilling and to quantify their interaction. There is no way to identify all the characteristics of drilling that might be important. However, many characteristics of the process can be observed, and

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in practice it is necessary to consider only a set of factors that adequately represent drilling conditions. Well characteristics are measured directly, while operator experience and wellbore quality frequently need to be represented by proxy variables. Many unobservable factors also impact drilling performance, such as well planning and preparation, project management skills, communication skills, and training.

The economic viability of marginal projects relies on a sound understanding of well costs and containment of the risks involved. Well costs are an important consideration in assessing the prospects of an exploration license. The choice of one exploration area over another may be influenced by differences in well costs. Despite the importance of well costs to the petroleum industry, forecasting well costs has been an imprecise process. Despite this collective wealth of drilling data and statistics, well operators often have difficulty predicting their well costs. This is due, in no small part, to the uniqueness of each well drilled. Lithology can vary significantly over short distances. Equipment and personnel vary from rig to rig. Well Non-Productive Time (NPT) caused by weather, difficult geology or equipment failure can result in substantial cost increases. Market rates for equipment and services are constantly changing. Lessons learned from previous wells are applied to improve the performance of subsequent wells with varying degrees of success.

The oil and gas industry invests significant money and other resources in projects with highly uncertain outcomes. In recent years, oil industry is heading to drill complex wells and unconventional targets where costly problems can occur and where associated revenues might be disappointing. In such case, companies may lose their investment; or may make a handsome profit. Oil companies are in an uncertain business. Assessing the outcomes, and assigning probabilities of occurrence and associated values, is how the company analyzes and prepares to manage risk.

Throughout the latter quarter of the 20th century, the oil and gas industry gradually started adopting the methods of uncertainty analysis, specifically decision trees and Monte Carlo simulation. Nowadays, the companies are searching in hostile conditions where they are facing many challenges which later affect the drilling cost analysis. Therefore, in the future new techniques must be developed to incorporate the issues of uncertainty regarding these environments so that the drilling cost analysis can be made with minimum error.

A new approach to drilling cost estimation has been established that provides a general framework for cost estimation using a formalized systems perspective. A generalized functional approach is developed that combines regression-based techniques, as used in the Joint Association Survey (JAS), with the multidimensional attributes of drilling, as incorporated in the Mechanical Risk Index (MRI), Directional Difficulty Index (DDI), and Difficulty Index (DFI) models. The JAS and MRI are the most popular methods used to evaluate drilling cost and complexity in the Gulf of Mexico. Specialized indices have been introduced to characterize the complexity of drilling directional and extended reach wells.

DOI: 10.7569/JSEE.2014.629520

The JAS estimates drilling cost using survey data and quadratic regression models constructed from four descriptor variables (API, 2002). The MRI is a risk index that uses six primary variables and 14 qualitative indicators to characterize wellbore complexity (Dodson and Dodson, 2003). A DDI and a DFI have been introduced to characterize the complexity of drilling directional and extended-reach wells (Oag and Williams, 2000; Shirley, 2003), and recently Mechanical Specific Energy (MSE) surveillance has been used to improve bit efficiency and performance and obtain a more objective assessment of drilling efficiency (Dupriest and Koederitz, 2005; Dupriest, 2006).

11 Future Trend on Drilling Cost Analysis

Drilling a hole in the ground in the search for or production of oil and gas is a complicated activity that is subjected to significant sources of variability. Although the physics of drilling is the same everywhere throughout the world, geologic conditions, contractor experience, equipment availability, well specification, and numerous other factors can lead to a wide range in drilling performance. Cost estimation is difficult and benchmarking efforts are often unreliable. Performance comparisons are mostly done on a well-by-well, actual-versus-plan basis, or seek to correlate costs to performance indicators, metrics, or drilling parameters.

To evaluate the differences that exist in drilling wells and to compare costs, it is necessary to establish statistically reliable relationships between performance metrics and the factors that impact drilling. The formation geology at the site and the location of the target reservoir is a primary factor that influences drilling cost. Geologic formations vary across the world, and indeed, within the same producing basin. Hard, abrasive, and heterogeneous formations typically have low penetration rates, frequent drillstring failures, and significant deviation from the planned trajectory. Deep reservoirs are usually characterized by low permeability, high temperature and pressure, complex fracture growth and stress regimes, and contaminants such as CO_2 and H_2S, which increase the complexity of the well and require operators to deal with a number of issues concerning safety and operational performance. The drilling methods used to make a hole depend upon the geologic formation and the technology applied, the amount of information known about the formation, the experience and preferences of the operator, available equipment, and the drilling contractor's experience and execution. Therefore, incorporation of all these challenging features brings the frontier thought for the future researchers.

The characteristics of the well are specified by the drilling plan, the location of the target reservoir, and the conditions encountered during drilling. Bit hydraulics has a major influence on drilling efficiency, and its role is complex since it is closely tied to other drilling variables, such as lithology, bit type, downhole conditions, mechanical drilling parameters, circulation system and drilling mud. Site characteristics such as the water depth, operators experience in the region, and expected

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environmental conditions influence the operator's decision regarding the selection of the contract and rig type, which in turn influence drilling performance metrics. Recently, the exploration companies are exploring unconventional resources such as shale and tight gas reservoirs, which could be uneconomical to explore with current technology, as they need more expensive tools. In the near future, a new model must be developed to incorporate the drilling cost of these uncertain behaviors of resources.

Over the past several decades, various methods have been proposed to evaluate drilling cost and complexity. However, because of the large number of factors and events that impact drilling performance, predictive models are difficult to construct. Quantifying well costs and complexity is challenging, due either to restrictions on data collection and availability, constraints associated with modeling, or combinations of these factors. Drilling rates are often constrained by factors that the driller does not control and in ways that cannot be documented, which creates a future challenge toward the estimation of drilling costs.

12 Conclusions

The article covers various methods that have been proposed over the past several decades to evaluate drilling cost and complexity. However, because of the large number of factors and events that impact drilling performance, predictive models are difficult to construct. Quantifying well costs and complexity is challenging, due either to restrictions on data collection and availability, constraints associated with modeling, or combinations of these factors. Drilling rates are often controlled by factors that the driller does not control and in ways that cannot be documented. The purpose is to review the primary methods used to assess drilling cost and complexity. This article discusses the list factors affecting well costs, estimate drilling time, list elements of well costing, calculation of well costs, understand NPT and risks associated with well cost estimation.

13 Nomenclature

A = constant, ft^{-1}
a_{dc} = constant depend on well location, $
b_{dc} = constant depend on well location, ft^{-1}
C_b = bit cost, $
C_f = drilling cost per unit depth, $/ft
C_o = all other costs of making a foot of hole, such as casings, mud, cementing services, logging services, coring services, site preparation, fuel, transportation, completion, etc., $
C_j = cost of the jth event, $
C_r = rig cost or fixed operating cost of the rig per unit time, $/hr
C_{dc} = drilling cost, $

DOI: 10.7569/JSEE.2014.629520

C_{cb} = core bit cost, \$
C_{cf} = coring costs per foot, \$/ft
C_{Tb} = total cost of the bits used for the whole drilling operations, \$
C_{Tr} = total cost of the rig paid as rent for the whole drilling operation, \$
C_{owc} = overall well cost excluding the production, \$/ft
D = total depth, ft
D_i = depth of interest from where drilling time would be measured for a given bit, ft
D_{i+L} = depth of interest up to where drilling time would be measured for a given bit, ft
$\bar{D}$ = mean depth of the well, ft
$\overline{D_t}$ = the mean depth where the trip was made (i.e. mean depth at the trip level), ft
E_d = drilling price elasticity
i = nominal interest rate per year or growth rate in fraction, \$
K = constant, ft/hr
$\overline{l_s}$ = the average length of one stand of drillstring, ft
m = number of interest compounding per year or the number of payments per year, nos.
n = number of years, nos.
N_b = numbers of bit, nos.
N_s = numbers of average stands of drillstring, nos.
P_j = provability of the j[th] event
P_{oil} = percentage change in the crude price
R = percentage change in drilling wells
R_c = core recovery factor, %
ROP = rate of penetration, ft/hr
t_c = connection time or non-rotating time during the bit run, hrs
t_d = drilling time or rotating time during the bit run, hrs
t_{di} = drilling time for a given bit i, hrs
$t_{d'}$ = drilling time required to drill from D to $(D + 1000)$, hr
$\overline{t_s}$ = the average time required to handle one stand of drillstring, hrs
t_t = trip time required to change a bit and resume drilling operations, hrs
t_{bl} = average bit life for a particular depth, hrs
t_{ct} = core trip time, hrs
t_{cr} = core rotating time, hrs
t_{cc} = core connection time, hrs
t_{crl} = core recovery, and laying down of core barrel time, hrs
t_{co} = coring time, hrs
V_f = future value, \$
V_p = present value, \$
V_{ex} = expected value, \$

DOI: 10.7569/JSEE.2014.629520

$\frac{dD}{dt}$ = rate of penetration, ft/hr

ΔD = formation interval drilled or drilled footage, ft

ΔD_{ROP} = the formation depth where the coring will be done (a function of rate of penetration), ft

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