Prediction of Pre-Drill Well Cost & Scope of NPT Management in Shallow Water, Western Offshore Basin, ONGC, Mumbai

A.K Vinod, Ashani Kundan*, Manoj Kumar, Vikrant Kalpande and Rakhi Pande

Summary

Exploration of hydrocarbons is a multifaceted and expensive business. The area anticipated to contain Hydrocarbons is subjected, to begin with, to acquisition of 2D, 3D, 4D / 4C seismic surveys. A team of Geoscientists narrow down the potential area after detailed integrated and interpretations of Geo-scientific data of the basin. Once the prospective area is identified with fair degree of confidence, the journey of exploratory drilling activity begins to determine presence or absence of oil and gas in commercially viable quantity. The geographical location of each well could be Offshore or Onshore and the well type Exploratory or Development, the well profile Vertical, Deviated or Horizontal. Predominately exploratory wells are vertical. The status would be Oil, Gas or Dry. Although the physics of drilling is same everywhere throughout the world, the geologic conditions, contractor’s experience, availability of equipments, well specifications and numerous other unavoidable factors can lead to a wide range of variations in drilling performance which further turn into undesirable escalation of well cost. The purpose of the study is to work out a predictive model for estimation of Pre-drill well cost in shallow water regime of Western Offshore Basin. The predictive well cost could vary with actual well cost due to several reasons and it becomes difficult for the operator to evaluate the comparative study between plan vs. actual well-cost and benchmarking efforts are often unreliable. The predictive pre–drill well cost mainly dependent on prognosed well depth, water depth, expected Formation Pressure and BHT for selection of drilling rigs.

More than 40 exploratory well data of study area reveals that, the target depth of oil and gas wells ranges from 1500m to 5400m, the Effective Operating Day Rate (EODR) of the drilling rigs varies widely dependent on rig capacity, generation and rig type. The well cost data aggregate has been analyzed and average values from these data are used to show the trends. Ideally, a correlation to determine how well costs vary with depth would use individual well cost data. Because of the wide variations, as Depth is only one of the variable controlling cost, the authors attempted to generate a predictive general trend chart by considering the average value of well depths and assuming normalized total well costs. More than 40 planned exploratory well cost data were studied and average costs are shown in (Table-2). The Wells below 1000m well depth and over 5000m are not included because of their less importance (on controlling the spread of data) to get accurate predictive well cost in this study. The analysis also brings out that nearly 75 to 80% of total well cost is due to drilling rig operating cost and the 20 to 25% belongs to drilling materials and support services and other contractual services expenses.

The biggest challenge for any E&P company is to arrest Non-Productive Time (NPT), principal factors contributing undesirable drilling cost. The drilling time analysis of study areas shows that the annual average NPT of completed well is about 30%. Easy Cost Planning (ECP) is a well cost estimation tool recently introduced in ONGC to analyze the pre-drill well cost from planning to production testing phase of oil and gas well. Plan vs. actual well cost variance analysis helps to construct the predictive model and could facilitate to improve the drilling efficiency for the future wells in the basin.

Keywords: Effective Operating Day Rate, Operating Day Rate, Tangible & Intangible, Easy Cost Planning, Non-Productive Time

Introduction

Energy import dependence has had a crippling effect India’s economy owing to sheer supply demand gap. Each year, India pays heavy price for its crude oil import dependency. The large part of India’s export earnings is eaten away by oil imports. Currently India is spending yearly to the tune of around $160 billion, increase by about 5 to 10% to fulfill yearly deficit. This fuelled substantial weakening of the Rupee in international market. The continuous depreciation of Rupee in international market. The continuous depreciation of Rupee in international market. The continuous depreciation of Rupee in international market. The continuous depreciation of Rupee in international market. The continuous depreciation of Rupee in international market.
activities in India. Such is the power of E&P sector in India.

The demand and supply graphs (Figure 1) depicts that the domestic oil production during the year 2011-12 was reported to be 34MMT against demand 172MMT and similarly domestic Natural gas production in the same year was 158MMSCMD against demand of 313MMSCMD. This clearly shows huge gap between supply and demand.

The current pace of domestic crude oil and natural gas production and demand to meet the requirement, the gap may be further expanded to 368MMT and 391MMSCMD respectively by the 2025. As per ONGC Prospective Plan 2030, (PP-2030) it is envisaged that India would need around 400MMtOE by 2030 with present growing demand of 3% per annum.

The Oil and Natural Gas Corporation Limited has geared up synergetic approach of exploration and drilling activities to produce from YTF (Yet to Find) potential of about 3.5 billion tons of Inplace hydrocarbons from 6 high potential areas like Deep water, CBM, Shale gas, HP/HT, Deeper plays and conventional Onshore & shallow plays. As per the statistics issued by the Directorate General of Hydrocarbons (DGH) on status of Exploration in Indian sedimentary Basin, only 22% of the total sedimentary basins were moderately to well-explored. The amount of oil and gas discoveries made so far depicts tremendous scope of unlocked Hydrocarbons potential in India. It is strongly believe that India’s Conventional Hydrocarbon Resources estimated to the tune of about 28,000 MMT of which Initial In-Place Reserves Oil and Oil equivalent Gas (O+OEG) 10,000 MMT. The recoverable reserves could be nearly 3,900MMT (O+OEG).

For any E&P company, it necessitates drilling sufficient number of exploratory and appraisal wells to find and convert hydrocarbons potential into producible asset. The E&P spending in India is also projected to rise to the tune of about $10 billion in 2012-13 compared to global E&P spending is a record $644 billion in 2013, up 7% from $604 billion in 2012. Oil and Natural Gas Corporation Limited is India’s most valuable national oil company contributes major part of E&P spending.

**Hydrocarbon Exploration Process & Wellbore Planning in Western Offshore Basin**

Hydrocarbon exploration of ONGC spread over seven sedimentary basins located in both onshore and offshore area (Shallow water and Deep water). The Director (Exploration) heads the exploration activities. Institutes like GEOPIC, KDMIPE, IRS, IDT and SPIC/RGL carry out the research and development work for exploration. The exploration group is also supported by;

- Geophysical Services for acquisition and processing of seismic data.
- Drilling services for drilling of exploratory and appraisal wells.
- Logging services for logging of the wells.

ONGC under its hydrocarbon exploration program, in its ongoing PEL’s/ML’s as well as NELP blocks under shallow water, deep water, and on land planned to drill 480 wells in 2012-13 as against 415wells planned for the previous year both onshore and offshore Petroleum Exploration License (PEL), Mining Lease (ML) and New Exploration Licensing Policy (NELP) areas. Out of 480 wells, 125 wells fall in offshore area of exploration. The total expected spending in Western Offshore Basin to drill the wells would be about INR15,000 crore ($3.0billion). Western Offshore Basin (WOB) carry out E&P activities in its ongoing PEL / PML as well as NELP block under shallow water from northernmost part of Kutch – Saurashtra offshore block to southernmost part of Kerala Kokan Offshore Block in west coast of India.
On an average, 20 to 25 exploratory wells are planned to be drilled each year in water depths from 15 to 90m. The target depth of wells varies from 1500m to over 5000m. Mainly two types of drilling rigs are deployed in shallow water of Western Offshore Basin. (1) Jack up rigs (cantilever type) and (2) Floater rigs (barge type). The Jack up type of rigs usually drills the locations situated in the bathymetry between 15 to 80m provided soil investigations tests are found to be positive. The floater rigs are deployed where locations failed to qualify soil coring test and water column fulfills the desired requirements. The mat types of rigs are deployed to drill the locations at very shallow water depth (<15m). High Pressure High Temperature (HPHT) floater and jack up rigs are also deployed to drill the locations where formation pressure is expected to be more than 10000psi and bottom hole temperature >350°F.

ONGC owns jack up and floaters rigs, but are inadequate to achieve minimum work program targets in stipulated time. The scarcity of drilling rigs and aging factor of departmental rigs compels ONGC to hire private drilling rigs from the market.

Motivation for the current study

The centrality of drilling budget to ONGC exploration program, and the need for a paradigm shift towards considering each exploratory well as a project had been the principal motivation for the current study. Costing a project being the vital foundation of a projectised enterprise led us to try to develop a pre-drill costing framework. Such motivations across the company were the prime mover for ONGC to adopt ECP, discussed further. However, cost elements of exploratory drilling elude a final and comprehensive definition because uncertainty which underpins the project execution, given that the arena of activity is really, the subsurface. The other uncertainty is Weather.

In this paper, we have reported how we have analyzed this uncertainty in terms of controllable risk (which can be addressed through continuous improvement of G&G analysis and drilling process) and uncontrollable risk (which requires a strategy of Broad Based Mitigation) and Force majeure (weather, whose adverse effect can be buffered through intelligent and diligent pre-planning). Last, but not the least, importance of strategic and tactical strengthening of our process through outside consultants and so on.

The Concept of Easy Cost Planning in ONGC

The concept of monitoring and analysis of drilling cost and time with estimated drilling cost was initiated by ONGC management in year 2008-09. The Executive Committee decided that all Assets and Basins shall prepare well cost estimates of both Development and Exploratory wells respectively beforehand. The plan vs. actual well cost variance analysis should be critically examined to arrest controllable Non Productive Time (NPT). The Easy Costing Planning (ECP) tool was developed in SAP system to felicitate correlation of plan and actual well cost. The practice of post drill well cost analysis should have been must criteria for every E&P company.

The well cost estimation of Pre-drill wells begins soon after finalization of Drilling program in association with multidisciplinary team members belonging to G&G, Drilling services, Mud services, Cementing services, Well services. The ECP module accepts the well cost data inputs in terms of quantity and company standardized material codes. The ECP also has provision of accepting the lump sum cost where for material cost or services cost is not been maintained in the SAP system. The cost elements uploaded in the system shall be classified in to three groups; the common cost or pre-spud, drilling phase and Production testing phase.

Input Parameters and Drilling- cost Breakdown

Operating day rate of drilling rigs is one of the principal constituent of Authorization for Expenditure (AFE) of any oil and gas well. It is pertinent to mention that the contract documents of charter hire drilling rigs are clearly defined with various components of service charges such as (1) Mobilization and De-mobilization charges (2) Operating Day Rate (ODR) (3) Non-Operating Day Rate (NODR) (4)
Equipment Break-down Day Rate (EBDR) (5) Moving Day Rate (MDR) i.e. movements between locations. (6) Any other integrated services charges wherever applicable. For every operating drilling rig, an Effective Day rate (EDR) is derived considering the average cost of mobilization, ODR, catering services, diesel charges, air logistics, marine logistics and shore base charges, other services like supply vessel charges etc. Thus common costs (spread costs) are built into EDR.

The drilling rigs commonly deployed in the study area are;
- Rig: Jack up (ONGC owned)
- Rig: Jack up (charter hire) Normal
- Rig: Jack up (charter hire) HPHT
- Rig: Floaters (charter hire)

The well materials, tools and technology required for drilling the oil and gas wells shall be grouped into tangible and intangible cost elements.

**INTANGIBLE COST ELEMENTS**
- Rig Hire, Rig Mobilisation & Demobilisation, Preparation & Voyage Time (Rig Movement).
- Soil coring or soil investigation (if applicable)
- Manpower, Drilling services, Mud services, Cementing services, Logging services, Well services etc.
- Air Logistics, OSV Logistics etc.
- Support services
- Insurances premium on the well etc

**TANGIBLE COST ELEMENTS**
- Casing Pipes, Liner Hanger, Production tubings etc.
- Well Heads & Blow out Preventor.
- Drilling bits and others drilling materials etc
- Mud line Suspension, Christmas Tree,
- Floating Equipments subsurface
- Navigational Aid / Buoys

Pre-drill well cost estimation is performed specific to the drilling prognosis. The ECP system maintains Effective Operating Day Rate (EDR) of drilling rigs and all types of drilling materials (imported or indigenous) per unit price are maintained as per company procedures. The input parameters for estimation of pre-drill cost can be grouped into;

**Common costs or pre-spud Cost:** The costs which don’t belong to a particular drilling phase such as (1) Rig move cost-time taken from previous location to the present location. The cost of this period is calculated based on Moving Day Rate (MDR) (2) Soil coring / GTV (Geo Technical Vessel operations) cost. (3) or any other consolidated cost which cannot be allocated to a particular phase of drilling or production testing.

| Common Cost or Pre-spud cost | • Rig Move Operating cost  
| | • Service cost  
| Drilling phase costs | • Rig Operating Cost  
| | • Material costs  
| | • Service costs  
| Production Testing phase costs | • Rig Operating cost  
| | • Material costs  
| | • Service costs  

**Figure 3: Well Construction Diagram**

**Drilling phase costs:** Exploratory wells drilled in study area shows that usually 3CP casing policy is adopted. (Figure-3). At times, 4CP & 5CP casing plan is also implemented depending upon the situation.

The input parameters for each phase of drilling shall be;

| Rig Operating days | • No of rig operations days allocated in each phase  
| Material cost | • Casings/Liner pipes, Drill Bits, Well Heads & BOP, Floating equipments, Centralizers, Cementing and Mud materials and chemicals  
| Services Cost | • Logging, Mud logging, Cementing services, Mud services, Support services etc.  

**Production Testing Phase:** The input parameters for production testing in the wells are:
Prediction of Pre-drill well cost

More than 40 exploratory wells considered in the study were limited to shallow water in Western Offshore Basin to determine general trends in drilling costs. In the study area of Western Offshore Basin, both departmental (ONGC owned) and contractual (charter hire) drilling rigs are deployed to drill exploratory wells. The contractual rigs are of two types (1) Jack up –Cantilever (2) Floaters-Drill Barge.

The well cost & its complexity analysis of study area carried out by aggregating the data inputs of pre-drill well costs and completed wells. The well cost presented in aggregate and average values from these data used to show the trends. There are various complexities involves during drilling the wells and therefore it is very difficult for the operator to maintain the records of each well cost estimate. It is very hard to integrate and match plan vs. actual cost variance with the present available tool. The author has generated various graphs and charts by considering the basic inputs like different types of drilling rigs involved in the study area, allocation of tentative drilling time to reach the target depth of the well. During the well cost analysis it is observed that rig operations time is the prime factor for exaggeration of total well cost. The study shows that average 75 to 80% of total well cost component are due to rig operating cost, 10 to 15% contributed by drilling materials such as casing pipes, drill bits, wellheads (WH), blowout preventer (BOP), floating equipment, Mud and Cementing materials. Approximately less <10% of well’s financial implications are due to support services and other contractual services like Wire line / LWD logging, Mud logging etc.

The Effective Day Rate (EDR) of each operating drilling rig are calculated and maintained in the SAP system. The pre-drill well costs are estimated based on EDR, which includes average charges of mobilization & demobilization, diesel, water, logistics (air, marine & land) and other services if applicable.

The predictive pre-drill well cost inputs can be broken based on common cost or pre-drill cost, different drilling hole sizes and production test phase.

The study reveals that the pre-spud cost involves rig’s movement period between drilling units release from previous location and its deployment at the new well location ready to spud. (The cost of this movement period is estimated based on Moving Day Rate (MDR)) and soil coring cost. Additionally, other costs such as rental charges of Logging unit and Mud logging units and support services expenses for rig move period are spread & built into pre-spud cost. The average rig movement time between the two locations is considered 10 days based on historic data for the planning purpose. It is observed that pre-spud cost is on an average 7% of the total well cost for the movements of rigs are within the basin as shown in (Figure-5) as an example. To the extent possible under the exploration program location sequencing in time can be aimed to bring this down.

Figure-4: Major Components of Well Cost
36” or 30” hole phase: which usually begins with pilling, or jetting of conductor casing, takes average 02days and the average depth of penetration in the study area is 142m, which is normally 80 to 100m below seabed. (Table-1). The average cost component for this phase is nearly 3% of the total well cost.

Table 1: Average meterage /day, phase wise

<table>
<thead>
<tr>
<th>Phase</th>
<th>Average meterage/day</th>
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<tbody>
<tr>
<td>26” hole</td>
<td>142</td>
</tr>
<tr>
<td>17 ½” hole</td>
<td>1529</td>
</tr>
<tr>
<td>12 ¼” hole</td>
<td>2683</td>
</tr>
<tr>
<td>8 ½” hole</td>
<td>2766</td>
</tr>
</tbody>
</table>

26” hole phase: Technically, when the bottom hole assembly tag the fresh formation during drilling of conductor casing pipes, the wellbore will be considered as spud. The average section depth of 26” hole will be around 583m may require average 5-6 days for completing the phase. The average drilling meterage per day could be around 100m and the tentative cost implication towards rig cost, drilling materials and support services of the phase could be around 5% of the total cost.

17 ½” hole phase: the average 17 ½” hole section target depth is 1529m in Western Offshore Basin. The 17 ½” open hole normally cased with 13 3/8” casing known as surface casing. The average drilling time required is 16 days inclusive of logging time. The average drilling rate of this phase of drilling is also around 100m per day and expected to consume nearly 14% of total well cost.

12 ¼” hole phase: the majority of drilling operator preferred to complete the wells in 12 ¼” or 8 ½” hole. Most of the target zones are expected to be encounter in these drilling phase hence require good borehole condition for proper evaluation of hydrocarbon presence in the well. The average sectional target depth of 12 ¼” borehole is about 2700m and average 30 days are needed to complete drilling, logging and casing cementation jobs. The 12 ¼” hole contributes nearly 27% of the total cost and probably the maximum to any other phases of the well cost.

8 ½” hole phase: the next most significant drilling phase in Western Offshore Basin is 8 ½” hole section. Majority of oil and gas wells drilled in the study area are likely to end up in 8 ½” drilling phase. This phase consumed the second highest cost component of the total well cost which is about 23% and may consume around 26 days to accomplish the required jobs.

6” hole phase: the least preferred drilling phase in the study area is 6” drilling phase and very few numbers of exploratory wells are drilled and completed in 6” drilling hole in the study area and therefore are excluded in developing the trends.

Production testing phase: Drilling of oil and gas wells not necessarily secure production testing in each well in any of the basins. Production testing in the wells normally conducted is based on indications of presence of hydrocarbons on wireline logs or fair degree of confidence level of observations during drilling. Our study shows that only 65 to 70% are subjected to production testing in Western Offshore Basin. The study revealed that in Western Offshore Basin, on an average 2 to 3 objects are planned for testing and average 10 days per object are allocated to carry out conclusive testing of the well. It has been observed that production testing takes up at least 15 to 20% of the total well cost if a well is taken up for testing.

Our strategy to bring down testing cost is reduction in the number of objects to be tested. This can be achieved through optimal deployment of formation testing on wire line through single probe as fluid identification (maximum extent) and sampling (where essential) and excessive pressure profiling. The other strategy is to scale step annulus pressure constraints through improved DST technology improving on and better activation and faster clean up, through clear fluids and flow assurance through timely interventions. But, apart from all these, time saving can be effected if testing is terminated intelligently at the right time when no other incremental benefits are expected through prolonged testing. Having 24 X 7 monitoring of testing operations and extensive use of technology that enable down hole gauge data to the surface during build up is bound to save time and money.
General trends in oil and gas well cost in Western Offshore Basin (Shallow water)

Predictive Pre-drill well cost model is developed by the author and co-workers. The model will assist to estimate the pre drill cost of oil and gas well of specific target depth range and rig type in shallow water environment of Western Offshore Basin. Efforts are made to draw trends considering the weighted average of well depths of more than 40 exploratory wells planned to drill with four different rig types viz. Jack up (ONGC owned), Jack up (charter hire), Floater (Charter hire) & Jack up (HPHT). The pre-drill well cost can be predicted from the trend model developed by collating and analyzing pre-drill well cost data inputs of more than 40 exploratory wells of Western Offshore Basin (shallow water) (Figure.8). The average cost of pre drill wells as shown in (Table-2) was compared with average well cost of completed wells (Table-3). The analysis shows that the average well cost of completed wells are severely affected by NPT especially in case of wells drilled beyond 3000m. This compelled the analysts to work out the quantum of NPT impact on the base value of estimated well cost. The drilling time breakup of Western Offshore Basin of last 5 years was analyzed and observed that an average 30% of rig time is contributed by NPT (Figure.7). Of which, on an average 17% are due to drilling related complications, 7% due to Waiting on Weather (WOW), 4% due to mechanical repairs and maintenance and only 2% because of waiting on man and materials. In real terms, the drilling complications of 17 % NPT with respect to total time are nearly 50% with respect to total NPT.

<table>
<thead>
<tr>
<th>Rig Types</th>
<th>Jack up (ONGC owned)</th>
<th>Jack up (Hired)</th>
<th>Jackup (HTHP)</th>
<th>Floater (Hired)</th>
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<tr>
<td>Target Depth (m)</td>
<td>Average well cost (INR, crore)</td>
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<tr>
<td>1000-1500</td>
<td>20.88 - - -</td>
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<tr>
<td>1500-2000</td>
<td>23.86 59.01 - -</td>
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<tr>
<td>2000-2500</td>
<td>26.42 55.58 - -</td>
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<tr>
<td>2500-3000</td>
<td>36.23 81.09 77.42</td>
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<tr>
<td>3000-3500</td>
<td>35.3 60.39 71.39</td>
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<td></td>
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<tr>
<td>3500-4000</td>
<td>62.47 - - -</td>
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<tr>
<td>4000-4500</td>
<td>- 98.77 184.4 123.08</td>
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<tr>
<td>4500-5000</td>
<td>- - 187.28 -</td>
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<td></td>
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<tr>
<td>5000-5500</td>
<td>- 181.54 217.24 148.41</td>
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Table 3: Post-drill Average Well cost (TD vs. Rig type)

<table>
<thead>
<tr>
<th>Rig Types</th>
<th>Jack up (ONGC owned)</th>
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<th>Jackup (HTHP)</th>
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<tr>
<td>1000-1500</td>
<td>35.93 - - -</td>
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<tr>
<td>1500-2000</td>
<td>- 42.96 - -</td>
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<tr>
<td>2000-2500</td>
<td>55.33 41.7 - -</td>
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<tr>
<td>2500-3000</td>
<td>58.01 73.35 52.39</td>
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<tr>
<td>3000-3500</td>
<td>89.88 106.55 101.88</td>
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</tr>
<tr>
<td>3500-4000</td>
<td>- 119.76 - -</td>
<td></td>
<td></td>
<td>138.51</td>
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<tr>
<td>4000-4500</td>
<td>- 89.25 117.53 253.65</td>
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<tr>
<td>4500-5000</td>
<td>- 299.03 257.32 341.17</td>
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<tr>
<td>5000-5500</td>
<td>- - 172.76 -</td>
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Analysis

Actual drilling days per meter match with Actual drilling days per meter after excluding NPT. Choice of Rig, Logistics and Material support are at par. Mechanical repairs and maintenance is still present albeit only 4% of the total rig days and 30% of NPT. This figure has been decreasing progressively and is expected to decrease further. This is relevant only to departmental Rigs.

NPT owing to drilling complications are neither rig specific nor rig type specific. They are fixed costs and have to be reduced. The contribution is 30% of rig time and 50% of total NPT. Our study brings out that this part of NPT can be broken down into controllable (Reduction of Risks) uncontrollable (Surprises). The reduction of risks includes;
Shoring up Geo-mechanics
Wellbore stability prediction
Reduction of casing policy through planned extra casing strings
Pore pressure and Fracture Pressure Gradient prediction
Outside consultancy for strategic and tactical support
Induction of Technology

Additionally

- In shallow water drilling, at least for key wells, bringing into the ambit of 24x7 monitoring.
- Interactions and engagement with chemistry and drilling teams continuously for achieving optimal mud engineering and special muds, drilling practices revision handling (Handling losses, Handling activity (kicks) unexpected reduction in formation drillability, G&G and Engineering synergy).
- Interaction of ONGC with the drilling operators.
- Hiring of consultants for strategic support and tactical advice.
- Improvement in scoping and specification of rigs tendered etc.

- Periodic meetings with service providers and prospective vendors with the indenting group will be helpful.

Expansion of the scope of war room is to include strategy inputs and long term planning inputs. A restructuring which differentiates offshore exploratory drilling as a separate vertical entities without compromising on lateral connection with other elements such as asset well drilling, as well as preserving support from centralized and corporate entities inside drilling group, in place of Functional/ Rig type wise structuring in drilling group.

Some Gain

- Ownership of problem as team problem (G&G and Drilling)
- Modifications in well plan, if engineering solution not feasible.
- Not getting bogged down in specifics but completing the well and moving on.

The surprises have to be handled in the spirit of safety risks (Hazards) and so mitigation strategy is

Allowance for

- Unplanned / contingency casing
- Procurement of special chemicals, cements and loss control fluids
• Budgeting for contingencies
• Continuous improvement of the way Kicks and Losses are handled through constant engagement between G&G and Engineering.

Conclusions

1. A reliable benchmark for well costing has been established that will help in building certain expenses which are likely to arise over and above prepared expenses for a realistic idea.
2. Deviation from expectations can now be quantified in terms of money and time to prioritize addressed strategies.

Acknowledgements

We would like to convey our sincere thanks to Oil and Natural Gas Corporation Limited, Mumbai for allowing to publish this paper. We would like to pay our special thanks to Mr. K. M. Sundaram, Ex. Executive Director, ONGC for his valuable guidance. Thanks to Mr. P. Seal, DGM (Geol.) and Geology Operations Group team members for their unconditional supports during the study.

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