WELL DELIVERY DIFFICULTY INDEX (“WDDI”)

A Unique Tool to determine the right and appropriate **Contingency** of a Well

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J. Muthu Kumar is an upstream oil and gas industry professional with 38+ years of experience across many countries with in-depth knowledge and extensive experience in:

- ✓ Asset Acquisition, Monetization and Development – to 1st oil and crude evacuation,
- ✓ Integrated Project Delivery,
- ✓ Well Construction and Well Intervention (Core Expertise),
- ✓ Short, Mid and Long Term Business Models,
- ✓ Systems, Policies, Principles, Procedures and Standards,
- ✓ Optimization and Integrated Project Risk Management,
- ✓ Emerging Technology Applications, and High Performance Coaching

iWells Integrated Management Consultants DMCC: iWells is specialized in drilling oil and gas wells with focus on well optimization, technical and operational integrity, effective drilling execution strategies, risk mitigation and prevention, integration of multi-disciplined approach to deliver complex projects through a defined well delivery and optimization process to reduce drilling risks, cost and carbon emissions.

1.0 Why Does Drilling Need a Well Delivery Difficulty Index?

Drilling:

- is a non-intuitive complex process highly prone to **non-linear and random risks****;
- is highly capital intensive, nearly 45-55% of field development cost is Drillex;
- risks exist in exploration, appraisal as well as field standard development wells;
- well cost experiences a step change increase every time a threshold of complexity is exceeded;
- complexity and risks are influenced by numerous factors which can lead to major or even catastrophic events like a blowout or major oil pollution;
  - → consistent and safe drilling performance requires extensive and effective integration of those factors;

*** - The causes and outcome of a risk is known or predictable in linear and non-random risks, whereas they are unpredictable and unknown in the non-linear and random risks, which may include black swan events.*

We define the **best well** as the one that is drilled seamlessly, problem free, with minimum non-productive time and within tolerable compromise to objectives.

However, we are unable to drill “”best wells” consistently all across. Majority of the wells experience a level of compromise to objectives including the common issue of time and cost over runs.

📖 *Despite advanced technologies, every day, at some part of the world, major drilling problems like side track, loss of well or a blowout (although rare), keep occurring.*

The standard Risk Register as in **Table 1** below, is inadequate to effectively manage the drilling risks.

No	Risk	Causes	Consequences	Pre-Mitigation			Mitigations	Post-Mitigation		
				P	I	S		P	I	S
1	Text	Text	Text	a_1	b_1	a_1 x b_1	Text	a_2	b_2	a_2 x b_2
2	Text	Text	Text	c_1	d_1	c_1 x d_1	Text	c_2	d_2	c_2 x d_2

P = Probability of Occurrence, I = Impact of Occurrence, S = Severity of Occurrence, which is a Product of P x I.
a, b c and d = number assigned from a scale (usually 1-4 or 1-5)

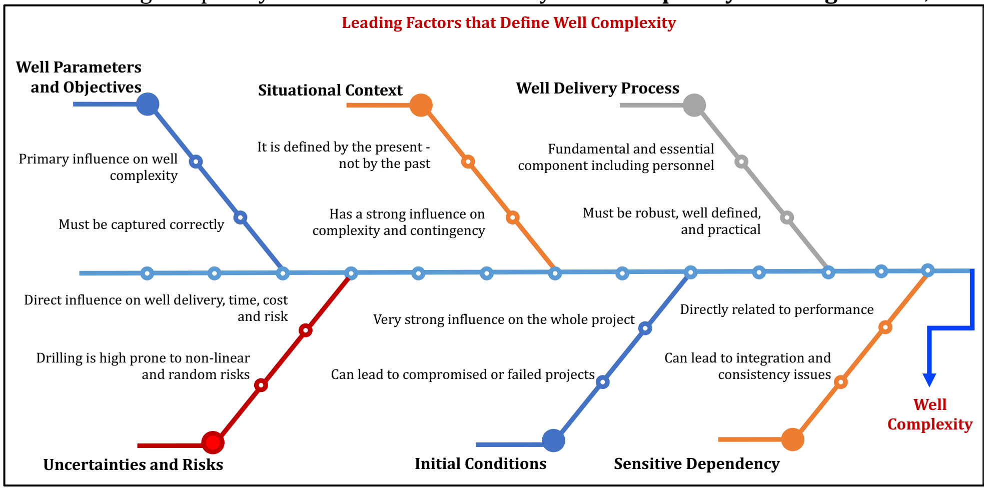
(1) The general risk register of **Table 1** deals with individual risks. Overall project risk is not determined.

(2) The P and I in the risk register are static numbers. In reality, they are dynamic. At any point of time, the P is only one number at that particular moment with an uncertain impact.

→ Hence, the magnitude of S, as it is merely a product of P x I, becomes a theoretical value.

(3) The mitigations for each risk are generally based on data, experience, and perceived confidence.

Drilling complexity and risks are influenced by **Well Complexity Defining Factors**, as in **Fig. 1.1.**

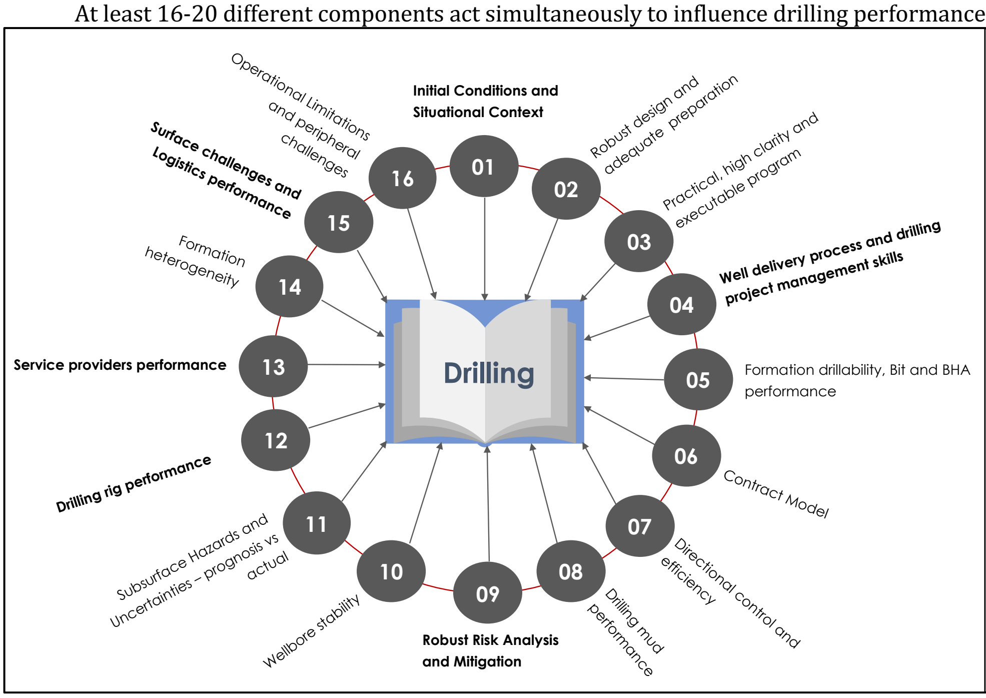


Situation context, initial conditions, sensitivity dependence and project execution are linked to uncertainty management and hence cannot be ignored.

It is not always a big one that creates a major impact, but it is rather a small cause that has escaped the attention. If unattended in time, it has the ability to create considerable impact.

Fig. 1.1 – Factors that Drive and Define Well Complexity

At least 16-20 different components act simultaneously to influence drilling performance.



For efficient and consistent drilling performance these factors must work in synchronization and harmony.

If drilling complexity and risks are treated only as "Details", then the team will not be prepared to face surprises and challenges during execution, thus leading to compromises to well objectives.

Hence, a properly defined well difficulty index and the right and appropriate contingency for each well are critical for effective drilling project management.

Fig. 1.2 – Factors with Direct or Indirect Influence on Drilling Performance

Hence, the leading goals and desire of every oil and company is to achieve:

(1) understanding the well delivery difficulty holistically and generating an appropriate **Contingency** for each well,

(2) a best fit practically achievable time and cost estimates with an executable program,

(3) a platform to implement an effective integrated drilling project delivery and risk management system.

WDDI is designed as a solution to generate the right and appropriate Contingency for every well.

2.0 Impact of Inappropriate Contingency of a Well

Inadequate estimate of contingency of a well has several impacts as discussed in **Table 2.**

Table 2 : Impact of Inadequate Contingency Estimates of a Well

No	Estimates	Model for Contingency
1	Low and Inadequate Contingency	x Leads to cost over runs / Impacts project economics. x Encourages compromises/tradeoffs to schedule, scope and deliverables
2	Over Estimated Contingency	x False sense of savings as estimates are overstated x Burden of debt by imposing additional capital than necessary.
3	Right and Appropriate Contingency	✓ Generates a robust, reliable and realistic business case, budget and economics ✓ Eliminates the shortcomings of the inadequate or overestimated contingency

The common practice in the industry for contingency is to apply general principles as in **Table 3.**

Table 3: Contingency Levels – Common Practice

No	Estimates	Model for Contingency
1	AFE or Level 1	+/-5% to +/- 15%
2	International Cost Classification System Accuracy Range: 80% Confidence Levels	**Example:** Class 2: Accuracy Range of -15% to +20% Class 1: Accuracy Range of -10% to +15%
3	Monte Carlo - Used widely for developing probability distribution	Not designed to generate contingency. It can be heavily biased impacted by Garbage In/Garbage Out.
4	P90 as contingency to P50	P90 is not a contingency value

Contingency considered using only the general principles without a comprehensive well complexity analysis, may make the project economics to appear robust but in reality, the chances of exceeding such contingency is high.

- → When exceeded, it impacts the project business case, economics and deliverables,
  - → which may even lead to suspension of a field development activity (which is not uncommon).

The challenge then is **"how to achieve the right and appropriate contingency of a well"?**

That is where the Well Delivery difficulty Index (WDDI) fits in as a solution to this challenge.

3.0 Drilling Difficulty Indexes in the Industry

Several indexes exist in the industry but not all of them are designed to generate **"Contingency"** of a well. Except a few, most are designed for benchmarking, time estimates and other specific purposes.

Some of the well-known popular drilling difficulty indexes are briefly discussed below. Discussions are limited to the application of indexes in determining "contingency levels" for a well.

Table 4: Drilling Indexes – in the Industry

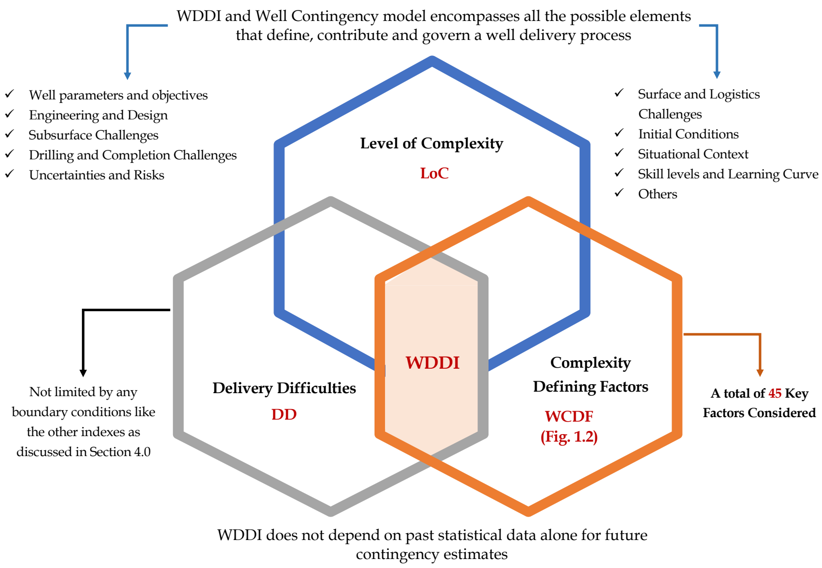
Index	Design	Limitations
JSA – Joint Association Survey	Developed to deduce the cost of an unreported well using data of annual survey of well costs in the US.	Not designed to generate Contingency of a well.
MRI – Mechanical Risk Index	Primarily to compare well operations and drilling performance in GoM. Its use is extended as a predictive tool during the design stage.	Not designed to generate Contingency of a well.
MSE – Mechanical Specific Energy	Developed for measuring drilling efficiency, especially the ROP. Uses factors that affect efficiency and that limit energy input.	It is limited to optimizing ROP and drilling efficiency. Not designed to generate Contingency of a well.
DDI – Drilling Difficulty Index (Schlumberger)	To classify the complexity of directional wells. The DDI is used to group wells of similar nature and complexity. It is then used for learning curve	Only applicable for directional drillability performance. Not designed to generate Contingency of a well.

	measurements and performance.	
DCI – Drilling Complexity Index	Designed to generate Contingency of a well based on factors that influence technical and geological complexity. Primarily used for planning/design to estimate time and cost contingencies. It is also used for benchmarking during execution and post drilling.	The range of 0-10 for defining complexity and contingency is too large. Please refer to Section 4.1. Does not consider all the Well Complexity Defining Factors (Fig. 1.1)
DI – Difficulty Index (K and M Technology)	To rank the difficulty in drilling an Extended Reach Wells (ERD). Not applicable holistically for a well delivery.	Only applicable to highly deviated and ERD wells. Not designed to generate Contingency of a well based on Well Complexity Defining Factors (Fig. 1.1)
RDI – Rushmore Drilling Index	Uses empirical data based on statistical data of large number of wells available with Rushmore. RDI might not depend on any expert opinion or subjective elements. Participating Operators can use the RDI model for performance benchmarking, plan, design and budget for new wells, estimating drilling time, and evaluate progress etc.	Not designed specifically to generate "Contingency" of a well based on Well Complexity Defining Factors (Fig. 1.1).

Each of the above listed difficulty index models are limited to certain boundary conditions and they are not designed to determine the **"contingency"** of a well except the DCI and to some extent the RDI. The WDDI is designed to generate the appropriate contingency. It is discussed further in **Section 4.1.**

4.0 How is WDDI different from other difficulty indexes?

WDDI is holistically designed to generate a realistic **"Overall Difficulty Level"** of a well and **"Contingency"** for that well.



First of all, it does not depend on past statistical data alone. WDDI is a holistic model without restrictions of boundary conditions like the other indexes, **Table 4.**

WDDI was developed uniquely using:

(a) qualitative and subjective elements (that require expert inputs), and
(b) **synthetic well models** ranging from very low to extremely high level of complexity.

Fig. 4.1– WDDI Model

The synthetic wells were created by modelling the Well Complexity Defining Factors (**Fig. 1.1**).

- Ten thousand synthetic wells were created to develop and train the WDDI algorithm.
- Three thousand synthetic wells were created to test the WDDI algorithm.

Please refer to **Section 7.0** for detailed discussion.

WDDI uses a very narrow range of scale at 0.05 increments as compared to a long scale range used by other indexes. This is critical aspect WDDI's narrow range removes averaging approximations.

4.1 Scales Followed by Other Drilling Indexes

Index	Scale	Limitations
JSA, MRI, DI and MSE	No scale, only a Number is produced to define the difficulty index.	Contingency is not generated.
DDI	Uses a scale between < 6 to > 6.8 with corresponding modifiers between -10% to +10%.	Fixed modifiers for directional drilling difficulty only.
DCI Uses a traffic signal model and scale for contingency.	DCI 0.0 to 2.9 = Low Complexity (Green) DCI 3.0 to 5.9 = Moderate Complexity (Amber) DCI 6.0 to 10.0 = High Complexity (Red) Scale range of 1 to 10 is large to capture adequately the relative difference between two subsequent sequences.	The DCI Index between 6 to 7 represents a contingency of 25% and index between 8 to 10 represents a contingency of 35%. This means that contingency is 35% whether the difficulty index is 8, 9 or 10. The 8-10 is a long range to have the same 35% as the contingency.

4.2 Scale Followed by WDDI

Index	Scale	Advantages / Uniqueness
WDDI	(1) A Minimum Threshold Value is determined by the well complexity level. (2) Starting at Minimum Threshold, the WDDI is determined for every **0.05** interval up to a maximum of 10.0.	The scale of **0.05** increments is very narrow and tight, which eliminates the large range of whole numbers between indexes. This minimizes, the averaging approximation.

WDDI Vs Well Contingency (derived from WDDI) Chart has Six Clear Slopes indicating that the Well Contingency escalates to a steeper slope at every subsequent higher Threshold Value, as in **Fig. 4.2.**

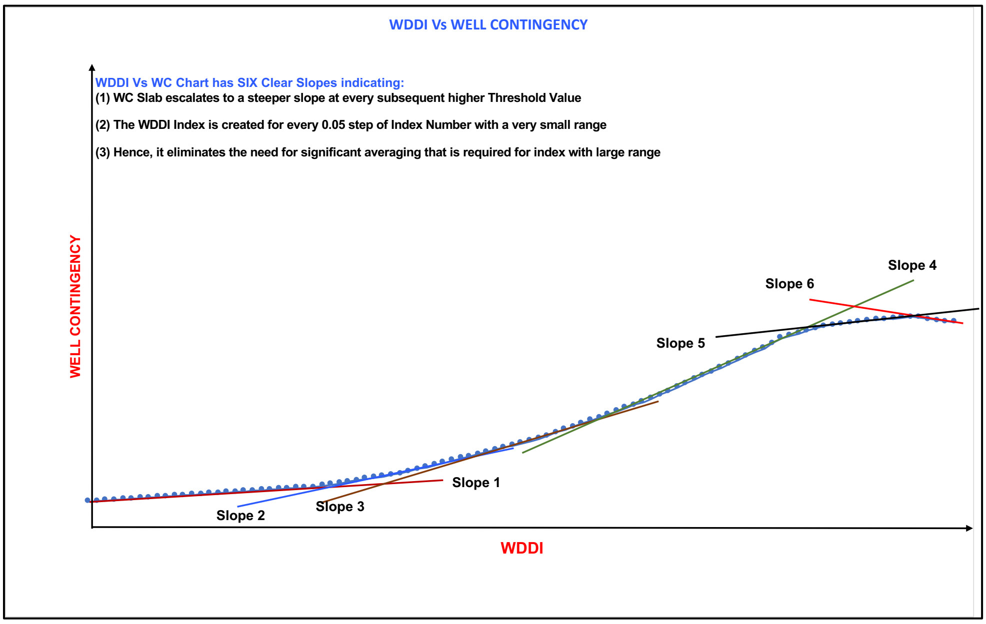


Fig. 4.2 – WDDI Vs Well Contingency Showing the Slopes

Hence, the Contingency generated by WDDI is highly dependable with low margin of error.

WDDI is a useful tool from concept, design and execution until the well is drilled and completed.

Table. 5 – Applications of WDDI and Well Contingency

Phase	WDDI Application
Planning	Helps to evaluate well complexity and determine right, and appropriate Well Contingency ("WC") based on well complexity defining factors (**Fig 1.1**). It complements the Most Likely estimates of time, cost and risk. It also allows a realistic model for project business case, economics and funding.

Detailed Design/Preparation	Impact of WDDI and WC on the Final Well Design and Program are reviewed, evaluated and added. Specific strategies and management philosophies to reduce the contingency during execution are developed.
Project Execution	Real time monitoring of performance, analysis, reporting and updating the WDDI model and re-strategizing execution real time.
Project Closeout	Through After-Action Reviews, SQMs and Performance Analysis post drilling to update the WDDI model and create a reference for future wells.

5.0 What is the Issue of using Statistical Past Data for Future Risk Predictions?

There is a natural impulse in the industry to use large set of statistical past offset wells data to predict risk, complexity, and contingency levels for future wells.

However, while the statistical past data are good for benchmarking and time estimates, they are inadequate for predicting complexity and contingency of future.

A new well may look similar to old wells on statistical data but they are not identical.

→ Patterns of the past do not necessarily represent the uncertainty of the future.
→ **Repeated patterns observed in large set of data will also indicate unpredictable variety.**
→ None of the patterns of the past will be **precisely** repeated. Only similar trends can be observed.
→ Technology existed/applied in the old offset wells may be different and much advanced in future.
→ Initial conditions, situational context and dependency would be different new and the past wells.
→ Past information must be normalized to remove outliers, risks and direct NPT.
→ Historical data may not represent true complexity and contingency levels of a future well.

If past statistical data alone has the ability to represent future complexity, then, there should not be:
∫ *Time and cost over runs and compromised or failed objectives of a well*
∫ *Side tracking, loss of a well, blow outs, fatality or a loss of assets*

However, as we know, the reality is different.

Please refer to **Fig. 5.1** below which explains the impact of situational context and initial conditions.

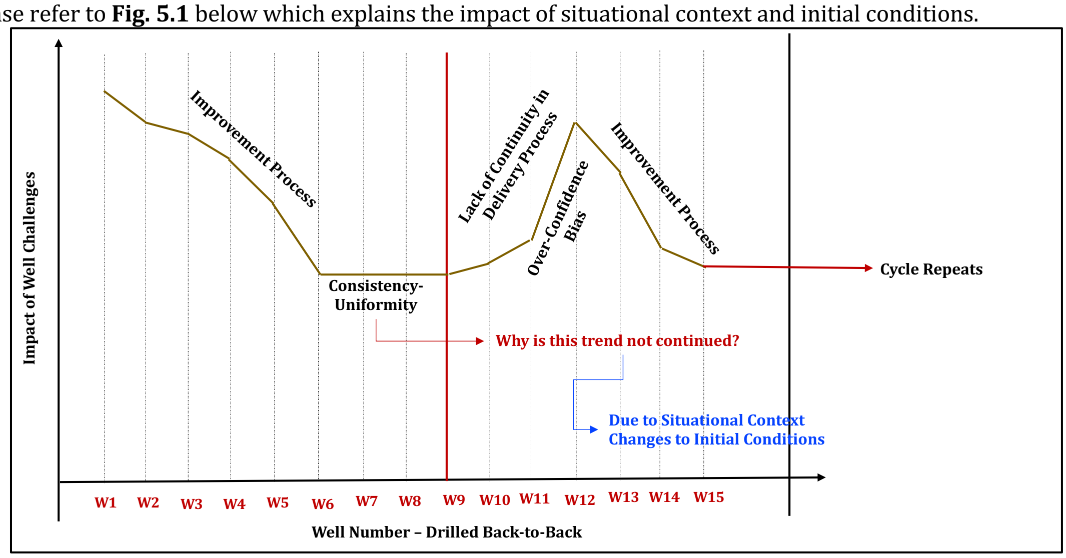


Fig. 5.1 – Concept of Actual Situational Context

In drilling, an improvement in certainty does not follow a symmetric upward scale/trend and an increase in uncertainty does not follow a symmetric downward scale/trend.

That is why in drilling, due to its non-linearity and random causes/effects, the deterministic model concept of, **if you do ‘a’, ‘b’ and ‘c’, the result will be ‘x’ and/or ‘y’ does not always work.**

Similarly, Regression analysis using past data has high chance of failure when applied to future in complex non-linear and random risk projects like drilling. **Fig. 5.2** below that explains the limitations.

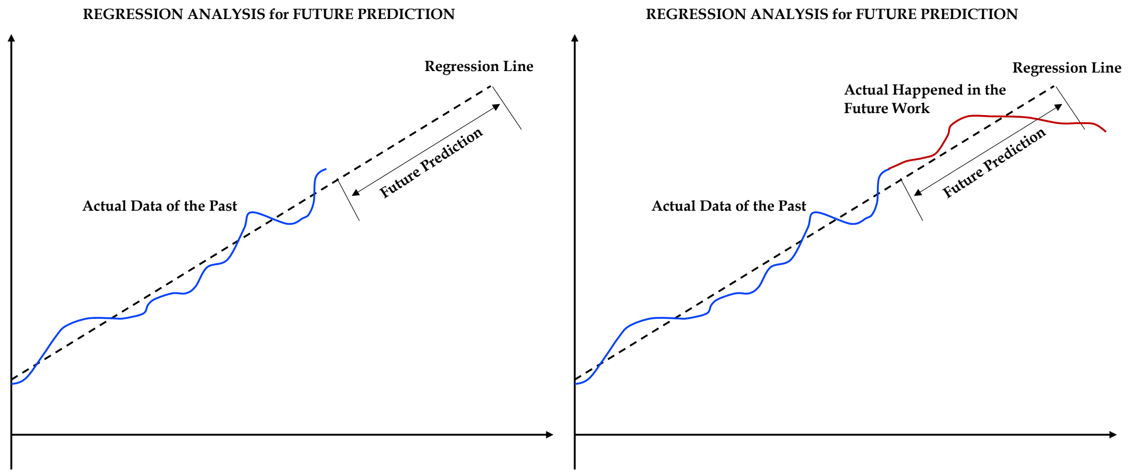


Fig. 5.2 – Regression Line Future Prediction Vs Actual

Hence, traditional statistical methods which depend only on past data and repeated observations cannot predict effectively the complexity, risk, and contingency of a future well.

WDDI is designed to work holistically by modelling the Well Complexity Defining Factors (**Fig. 1.1**).

6.0 WDDI and Well Contingency Methodology

WDDI considers **45 Key Factors** that have direct or indirect influence on the drilling efficiency, risk management, time and cost. Please refer to **Table 6** below,

WDDI Stages:
WDDI works on Five (05) Stages as shown in **Fig. 6.1** below. Factors that affect the well complexity and contingency levels are categorized into three groups.

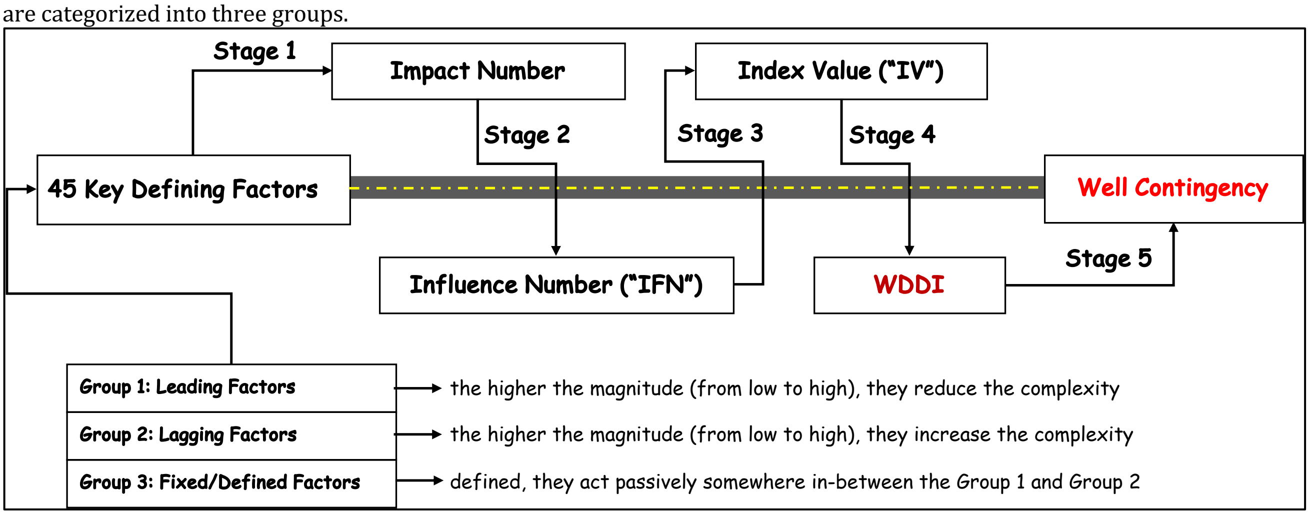


Fig. 6.1 – WDDI Stages

Stage 1: Impact Number - A unique impact number is allocated/defined for each of the Key Factors.

(1) A % weightage for each of the Key Factor is selected based on the parameters of the well to be drilled and organization policy. The sum of weightage of each Key Factor within that Group is 100%.

(2) After Step (1), the impact number for each Key Factor will be assigned from a Fibonacci sequence:
1 (Low), 2, 3, 5, 8, 13, 21, 34, 55, 89, 144 (High).

Note: The reason for choosing Fibonacci Sequence for Impact Number is not explained in this paper.

Stage 2: Influence Number - An Influence Number is generated by multiple steps and four different algorithms / formulas. To avoid "bias" from creeping in,

(1) The impact number will be run through multiple iterations across a defined uncertainty range (low, mid, high).

(2) Four different IF numbers will be generated ***(which increases the robustness of the model).***

Stage 3: Index Value - An Index Value will be generated as the final number to calculate the WDDI.

(1) All the four IF values generated in Step 2 will be integrated by two different algorithms/formulas to produce the Index Value.

(2) The Index Value from the two formulas must be equal ***(validation of the model).***

Stage 4: WDDI - WDDI is generated from the Index Value.
The Index Value is used to generate WDDI by an algorithm ***(made of a polynomial order of six).***

Stage 5: The **Well Contingency** is then generated.
The Well Contingency is generated from WDDI by another independent algorithm ***(made of a polynomial order of six).***

The model, through the steps above, converts the subjectivity to objectivity by applying the right "Questioning Principles", logical sequences, variance and uncertainty ranges to determine WDDI.

WDDI practically eliminates Garbage In/Garbage Out scenario to the maximum extent possible.

Table 6: The 45 Key Factors

No	Key Factor		Variable
	Group 1: Leading Factors		
1	Initial Conditions	6	Technology / Crew Efficiency
2	Continuity and Consistency	7	Engineering/Program/Preparation
3	Operator and Project Leadership	8	Clarity of Design/Program Scope
4	Well Delivery Process	9	Rig Capability and Limitations
5	Project Management Skills	10	Contract Model
	Group 2: Fixed/Defined Factors		
11	Well Category	18	Maximum DLS, Deg/30 m
12	Environment	19	Tortuosity
13	Well Depth	20	Target Tolerance, in ft
14	Well Profile	21	Mud Type
15	Azimuth Model	22	Number of Casing Strings
16	Aspect Ratio	23	Basis/Level of Time and Cost Estimates
17	Well Type		
	Group 3: Lagging Factors		
24	Pore Pressure, ppg	35	Loss Zones / Weak Formations
25	BHST, Deg F	36	Unconventional Activities
26	Reservoir Type	37	Logistics Challenges
27	Shallow Gas	38	Mud Weight, ppg
28	H_2S and Others	39	Operational Limitations
29	Formation Un-Drillability	40	Surface Challenges
30	Formation Type, Hardness and Abrasiveness	41	Sub-Surface Challenges
31	Troublesome Formations	42	Drilling Challenges
32	Wellbore Stability Issue	43	Completion Challenges
33	Formation Heterogeneity	44	Schedule Challenges
34	Abnormal Pressures	45	Design/Program Uncertainties

6.1 What is the Maximum Well Contingency from WDDI?

The well contingency cannot be a continuously increasing value. At a threshold, it will start experiencing a resistance to the increasing trend, due to the increasing ability of execution at a rate to match with the well complexity.

→ A highly complex well will not be drilled by any company with a mediocre team and systems.

Prudent companies treat every well (complex or field standard) with due respect, but some ignore the inherent risks for field standard wells due to **"success paradox" or "confirmation bias".**

→ This causes the team not to be prepared to face challenge if surprises occur during execution.

If the estimated well contingency exceeds a practical limit, say > 30%, the design, program, risk mitigation, and strategy are to be re-evaluated and re-validated to reduce the contingency levels.

Determining contingency is a repeated cycle with re-validation process. This is a secondary advantage of determining contingency from a properly estimated WDDI instead of using arbitrary or random contingency levels.

The WDDI model works according to this principle as shown in **Fig 6.2.** As the execution ability increases, the well complexity starts to flatten and then drop.

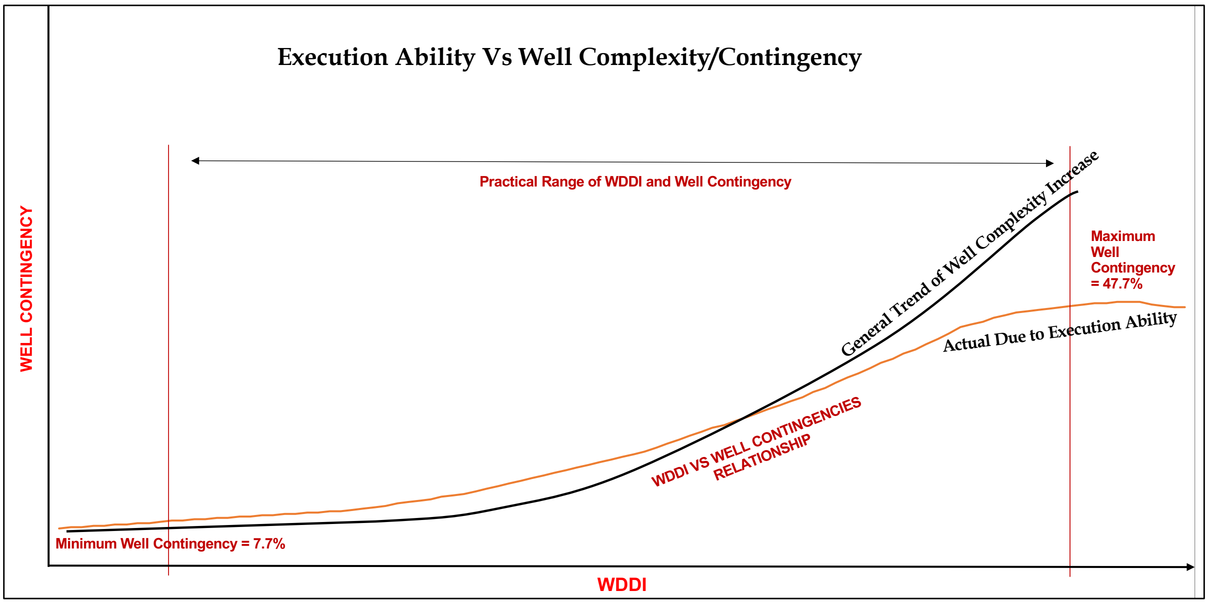


Fig. 6.2 – Execution Ability VS Well Complexity/Contingency

6.2 What does WDDI and Well Contingency Denote?

The **Contingency** derived from **WDDI** is not a definitive "will happen" number. It represents that:

- ✓ the estimated time, cost and risk has the potential to increase **up to** the estimated Contingency.
- ✓ It recommends the percentage of contingency to be considered in the time, cost and risk models.

Fig. 6.3 – Complement of Well Contingency to Most Likely Estimates of Risk, Time, and Cost

6.3 Is there a Linear Correlation between WDDI and Key Performance Indicators ("KPIs")?

A well difficulty index should not necessarily correlate with KPIs.

→ The factors affecting the well complexity and KPIs are contradictory and act like opposing forces.

→ If a linear correlation is found between well complexity and KPIs, then it is probably due to "Confirmation or Cognitive Bias", derived from data, trends and perceived understanding.

It is obvious that more the wells drilled in a field/environment, the less complex the wells will become.

- *a wildcat offshore exploration well is more complex than a standard vertical well on land.*
- *a HPHT-ERD well on land is more complex than a vertical normal PP Deep Water well.*
- *1st well in DW is more complex than the 10th well of an ERD shallow offshore well.*

The hindsight analysis post drilling is ineffective to find the true underlying root causes for events and challenges encountered.

A well difficulty index estimated based on Well Complexity Defining Factors (**Fig. 1.1**) without bias, can only have a non-linear relation to any of the key performance indicators.

7.0 Examples of WDDI Application

The four examples shown in Table 7 below vary from low difficulty to extreme difficulty level. Example 4 is impractical but it is included to demonstrate the concept.

Important Note: Due to the difficulty to exhibit the derivation of the input parameters followed as per **Section 6.0 – WDDI Stages,** the Table below shows only the difficulty levels to create an understanding of the difference in difficulty levels between each Example. The actual calculations were done by processing the steps as in **Section 6.0**.

Table 7: Examples of WDDI Application

No	Key Factors	Example 1	Example 2	Example 3	Example 4
	Difficulty Level / Complexity	Low Difficulty	Medium Difficulty	High Difficulty	Extreme Difficulty
	Well Complexity Defining Parameters	Very High Strength	Medium Strength	Medium-High Strength	Low Strength
	Resulting WDDI and Well Contingency	Normal-Low	Low-Medium	Medium-High	Very High (Impractical)
	Group 1 Factors				
1	Initial Conditions	Highly Favourable	Favourable	Challenging	Weak
2	Continuity and Consistency	Robust	Consistent	Weak	Weak
3	Operator and Project Leadership	Strong	Fit for Purpose	Lower Experience	Very Low
4	Well Delivery Process	Robust	Established	Workable	Poor
5	Project Management Skills	Well Established	Standard Model	Manageable	Poor
6	Technology / Crew Efficiency	Advanced / High	Standard / Average	Fit for Purpose	Inadequate
7	Engineering/Program/Preparation	Robust	Usable	Manageable	Inadequate
8	Clarity of Design/Program Scope	Very Good	Good	Manageable	Low
9	Rig Capability and Limitations	High	Good	Fit for Purpose	Inadequate
10	Contract Model	Strong	Balanced	Practical	Weak
	Group 2 Factors				
1	Well Category	Development	Appraisal	Exploration	Exploration
2	Environment	Land	Shallow Offshore	Deep Water	Deep Water
3	Well Depth, TVD / MD	7,900 ft / 13,200 ft	7,800 ft / 14,800 ft	8,200 ft / 22,100 ft	8,200 ft / 22,100 ft
4	Well Profile	B-H	B-H-D-B	B-H-D-B-H	B-H-D-B-H
5	Azimuth Model	2D	3D	Complex 3D	Complex 3D
6	Aspect Ratio	0.65	1.9	2.7	3.0
7	Well Type	Deviated	Highly Deviated	ERD	ERD
8	Maximum DLS	2.2^0 / 100 ft	3.3^0 / 100 ft	4.2^0 / 100 ft	4.2^0 / 100 ft
9	Tortuosity	Low	Medium	High	High
10	Target Tolerance	> 50 ft	> 25 ft < 50 ft	> 10 ft < 25 ft	> 10 ft < 25 ft
11	Mud Type	SOBM	SOBM	SOBM	SOBM
12	Number of Casing Strings	3	4	6	6
13	Basis of Time and Cost Estimates	Robust	Practical	Manageable	Inadequate

	Group 3 Factors				
1	Pore Pressure Profile	Normal	Normal PP + 30%	High, Normal PP + 70%	High, Normal PP + 90%
2	Temperature Profile	Normal	Normal TP + 20%	High, Normal PP + 50%	High, Normal PP + 70%
3	Reservoir Type	Clastic - Sandstone	Carbonates	Combination	Combination
4	Shallow Gas	Low Probability	High Probability	Expected	Expected
5	H_2S and Others	No	Low Probability	Yes, Expected	Yes, Expected
6	Formation Un-Drillability	Medium	High	Very High	Very High
7	Formation Hardness / Abrasiveness	Soft-Medium / Low	Medium / Medium	High / High	Very High / Very High
8	Troublesome Formations	Low Impact	Medium Impact	Very High Impact	Very High Impact
9	Wellbore Stability Issue	Low Impact	High Impact	Very High Impact	Very High Impact
10	Formation Heterogeneity	Low	Medium	High	Very High
11	Abnormal Pressures	Nil	Medium, Abrupt Transition	High, 1 Pressure Reversal	High, 2 Pressure Reversals
12	Loss Zones / Weak Formations	Low Probability	Medium Probability	Expected	Expected
13	Unconventional Activities	Nil	Minor	Major	Major
14	Logistics Challenges	Low	High	Very High	Very High
15	Mud Weight	8.8 ppg	11.7 ppg	15.4 ppg	18.4 ppg
16	Operational Limitations	Low	Medium	High	High
17	Surface Challenges	Low	Medium	High	High
18	Sub-Surface Challenges	Medium	High	Very High	Very High
19	Drilling Challenges	Medium	High	Very High	Very High
20	Completion Challenges	Single String Single Zone	GP CH Dual Completion	CHGP Single Zone	CHGP Single Zone
21	Schedule Challenges	Low	Medium	High	High
22	Design/Program Uncertainties	Low	Medium	High	Very High
MODEL OUTPUT					
The calculations were done by processing the steps as in Section 6.0.					
A	**WDDI**	**5.81**	**7.13**	**8.53**	**> 10.0**
B	**Well Contingency (WC)**	**9.6%**	**16.5%**	**35.0%**	**> 60.0%**
C	Estimated Time P10/P50/P90	23.0 / 28.0 / 41.0 Days	34.0 / 43.0 / 59.0 Days	42.0 / 52.0 / 72.0 Days	This is an impractical model. This Example is shown only to demonstrate that such low leading and high lagging factors are not practical and will never happen in reality. Hence not calculated.
D1	Most Likely Time, PERT Model	29.8 Days	44.9 Days	54.5 Days	
D2	Most Likely Time, iWells Model	29.7 Days	44.9 Days	54.3 Days	
E	Most Likely Time, Higher of D1 and D2	29.8 Days	44.9 Days	54.5 Days	
F	Most Likely Time + Contingency	29.8 x 1.096 = **32.7** Days	44.5 x 1.165 = **52.3** Days	54.5 x 1.35 = **73.6** Days	
G	Estimated Cost P10/P50/P90	US$ Million 11 / 15 / 22	US$ Million 19 / 24 / 34	US$ Million 22 / 29 / 41	
D1	Most Likely Cost, PERT Model	US$ Million 15.8	US$ Million 25.6	US$ Million 30.8	
D2	Most Likely Cost, iWells Model	US$ Million 16.0	US$ Million 25.7	US$ Million 31.0	
E	Most Likely Cost, Higher of D1 and D2	US$ Million 16.0	US$ Million 25.7	US$ Million 31.0	
F	Most Likely Cost + Contingency	16.0 x 1.096 = US$ 17.5 MM	25.7 x 1.165 = US$ 29.9 MM	31.0 x 1.35 = US$ 41.9 MM	

Notes: The PERT Model and iWells Model as in D1 and D2 above are not discussed here. However, it is important to note that P50 is not the Most Likely Case. The Most Likely depends on the degree off skewness between P10-P50 and P50-P90 .

8.0 Output Report of WDDI and WC

A typical report only for points (3), (4) and (5) is shown for reference only.

WELL DELIVERY DIFFICULTY INDEX
WELL CONTINGENCY

WDDI ABC OIL AND GAS

Date:

Company Name:	ABC Oil and Gas Limited	Project Name:	XYZ - Exploration Program
Field Name:	XYZ	Well Name:	XYZ-A-1

REPORT:

Estimated WDDI: 7.85

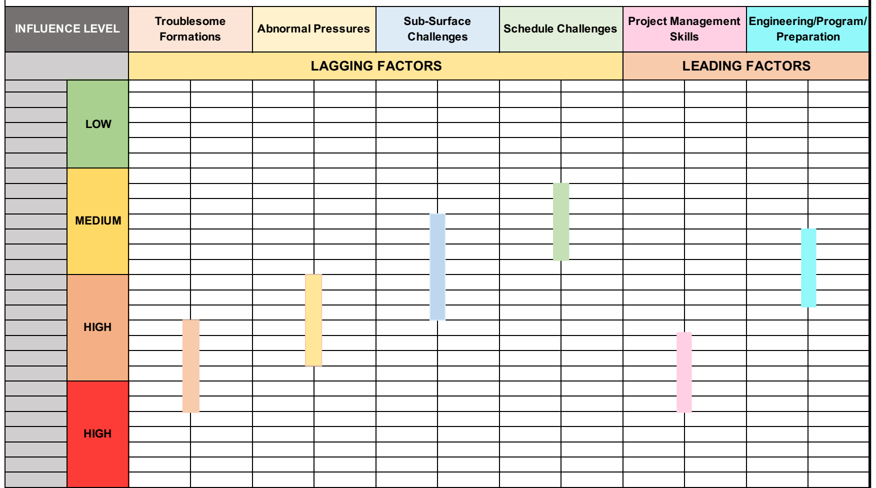
WDDI Generated Well Contingency: 24.6%

APPLICATION:

Most Likely Estimate of Time:	52.0	Days	The contingency time denotes the potential for the esimated time to increase up to the Contingency. It is not a fixed number but a potential **"Up To"** number.
Contingency Time Can Go Up To:	12.8	Days	
Most Likely Time + Contingency	**64.8**	**Days**	

Most Likely Estimate of Cost:	28.2	US$ Million	The contingency cost denotes the potential for the esimated cost to increase up to the Contingency. It is not a fixed number but a potential **"Up To"** number.
Contingency Cost Can Go Up To:	6.9	US$ Million	
Most Likely Cost + Contingency	**35.1**	**US$ Million**	

Factors That Influenced the Contingency:



ANALYSIS of the RESULTS: ONLY A BRIEF DISCUSSION IS PROVIDED FOR THIS EXAMPLE

Areas to Focus:	
Lagging Factors:	Detailed analysis will be added to the actual report.
Leading Factors:	Detailed analysis will be added to the actual report.
Other Factors:	Detailed analysis will be added to the actual report.

The output report of WDDI and WC would contain majorly the following:

(1) The summary of input data
(2) Input data validation and the Process
(3) Estimated WDDI and Applied Contingency Values
(4) Most Likely Time and Cost Estimates + Contingency
(5) Factors that had the highest influence on WDDI and Contingency
(6) Detailed Analysis of the Results
(7) Recommendations and Conclusions

Examples given in Section 7.0: The derived Contingency in Examples 1 and 2 are more or less within the common industry practice levels.

However, the Contingency of Example 3 may raise a question on the reliability as it shows a potential increase up to 35.0% to the time and cost.

Example 3 shows that such high contingency is required in a combination of high complex well with low-medium strength of situational context, initial conditions, delivery process and project management skills.

The advantage of high contingency in Example 3 in a real scenario is that it cautions to evaluate and validate to optimize the well design and program.

In Example 3, the sum of Most Likely + Contingency is tending towards P90 values. Is it typical?

P90 is not a contingency and cannot be used for contingency. By definition, P90 and Contingency are entirely different.

- ✓ Contingency is an **Up To** Number. It is not the worst case.
- ✓ The "P" in P90 denotes **Percentile** and not **Probability.** P90 does not mean that it has 90% chance of occurring.

P90 is a worst case where there is only a 10% chance that the P90 number will be exceeded or 90% chance the P90 number will not be exceeded. This is different from stating it has 90% chance of occurring.

So Contingency value is independent of P90 value. However, if the sum of Most Likely+Contingency tends towards or exceeds the P90 value, it is a caution to re-analyze to remove any inconsistencies in the estimates.

This also helps as a check and balance tool to ensure that the design and estimates are robust.

9.0 Conclusions

It is an irony that despite being an industry of nearly hundred years with advanced technologies that were developed in the last three decades, the drilling industry is unable to minimize (or eliminate) the risk and achieve top performance to deliver "best wells" consistently all across the industry.

The major reasons were briefly discussed in this document. As a recap, the following critical points are provided:

(a) inadequate appreciation of inherent non-linear and random risks and uncertainties in drilling;

(b) treatment of drilling as a service unit and drilling risks/complexities as "Details" which creates limiting conditions starting from the project framing phase itself;

(c) relying too much on the past statistical data and static analysis to predict future risk;

Some major conclusions or resolutions derived in this paper are:

(1) Drilling risks are influenced by Well Complexity Defining Factors (as in **Fig. 1.1**) especially the situational context, initial conditions, sensitive dependency and well delivery process.

→ They are linked to organization context, project execution framework and uncertainty management.

(2) Traditional statistical methods which depend on past data and repeated observations cannot predict future complexity, risk, and contingency.

(3) Contingency of a well must be determined through a properly estimated well difficulty index and not using the general principles (as in **Table 3, Section 2**).

(4) Determining the right and appropriate contingency of a well based on properly determined well complexity/difficulty index is a challenge.

WDDI was developed as a Solution to the challenges listed above:

(1) WDDI is an independent tool that generates **a holistic well delivery difficulty index and the right/appropriate contingency** of a well, which is then complemented to the Most Likely estimates of time, cost, and risk models as discussed in this paper.

(2) The Contingency generated through the WDDI also allows a good understanding of the impact of drilling complexities to the overall project cost, economics, and funding.

(3) The WDDI and Contingency determined during the planning phase will generate higher focus and attention to minimize the impact during execution by establishing all the required mitigations, reliefs, and improvements.

To conclude, the Contingency of a well determined by the WDDI Model:

- ✓ delivers the leading goals and objectives as discussed in Section 1.0;
- ✓ delivers the merits of right and appropriate contingency as discussed in Table 2 in Section 2;
- ✓ generates a robust, reliable and realistic business case, budget and economics;
- ✓ eliminates the shortcomings of the inadequate or overestimated contingency;

Hence, the WDDI and Contingency derived from WDDI are an essential drilling project management tool for planning, executing, and delivering every well.

10.0 Further Contacts

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References:

I acknowledge and heartfully thank all my peers, colleagues, mentors and superiors as well as authors of technical books, thinkers, and blog writers who had showered their knowledge for me to learn, create an awareness, understanding and interest on this subject. I have given the list of references below but if any is missing, it is unintentional, and I thank all who made this write up possible.

No	Details	No	Details
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