IADC/SPE 151448

Improving Casing Wear Prediction and Mitigation Using a Statistically Based Model

Sarah Mitchell, WWT International
Yanghua Xiang, Pegasus Vertex International

This paper was prepared for presentation at the 2012 IADC/SPE Drilling Conference and Exhibition held in San Diego, California, USA, 6–8 March 2012.

Abstract

Wells are now routinely drilled both in deepwater and on land to depths that were previously considered impossible. In these environments, casing design is critical to safely and successfully drilling and producing wells, and unexpected casing wear can result in significant costs or even the loss of a well. As part of a successful casing design strategy, the engineer must assess the maximum permissible casing wear required to maintain casing integrity. Then, steps must be taken to ensure that casing wear thresholds are not exceeded.

Casing wear models use the number of drill string revolutions and contact force between the drill pipe and casing to calculate wear. The contact force is calculated using the dog-leg severity within the well, with the maximum dog-leg severity often determining the location and extent of the most severe casing wear. There is often a large discrepancy between predicted and actual casing wear because of survey quality and inaccurate estimates of dog-leg severity and total revolutions. These discrepancies result in predictions of contact force and drill string revolutions that are in error by 50% or more.
To improve the accuracy of casing wear models, an extensive database was created from a wide variety of wells with measured depths greater than 13,000ft. The database results in a statistically based model for determining dog-leg severity within vertical, build, and tangent sections, as well as total drill string revolutions at various levels of confidence to bound average and maximum expected contact force and casing wear.

Case histories compare measured wear with predictions of casing wear based on original well data and the statistically based model. The case histories also demonstrate the effect of various drilling parameters on casing wear, and evaluate the effectiveness of non-rotating protectors in preventing casing wear.

Project Goal

The goal of this project was to more accurately quantify casing wear risk by improving casing wear analysis accuracy. To do this, data from a large number of wells was analyzed to generate probabilities for dog-leg severity in common well types and also correlate those to actual backmodeled casing wear factors. The results will allow an engineer to analyze what the expected casing wear might be for an average (P50) horizontal well, and then evaluate the maximum expected wear for a 1 in 10 case (P90), 1 in 20 case (P95), or 1 in 100 (P99) case.

Surveys

All casing wear software, and torque and drag software as well, use a directional survey to determine the side force or contact force between the drill string and wellbore. These points within a directional survey can be a representation of a planned well path, or it can be taken from actual downhole measurements. The survey points are then connected into a single line representing a best approximation of the wellpath with the information given.

For many reservoir engineers, the positional accuracy of the wellpath is important only in terms of determining if the well reached the targets. But for casing wear modeling, the side force or contact force between the drill pipe and casing has a direct effect on wear rate. Lubinski (1961, 1984) have shown that the severity of curvature in the wellbore is related to the contact force. The severity of curvature in a well is represented as dog-leg severity “DLS”, normally expressed in °/100ft or °/30m.

Tortuosity

In modeling a well using a planned wellpath, an amount of ‘tortuosity’, or artificial curvature, is added to an otherwise perfectly smooth planned wellpath to more closely represent the quantity and magnitude of curvature that will be inherent in the real wellbore. Tortuosity can take many forms, including sinusoidal, helical, or randomly generated deviation as shown by Samuel (2005) and others. In modeling a well using actual surveys, the distance between survey points, also called the survey station frequency, and the accuracy of the tool taking the measurements, can greatly influence the accuracy of the calculated wellpath to the actual path of the wellbore.

The way that the tortuosity is used is important. Because the effects of torque and drag are cumulative over the entire drill string, the effect of dog-leg severity and resulting contact force at any one point is not as important as the overall average level of contact force over the entire well. In contrast, when modeling casing wear, the goal is to calculate the minimum burst and collapse pressures for the casing string resulting from the maximum amount of casing wear. In this case, the maximum dog-leg severity value, and not the average dog-leg severity, is important because an acute dog-leg over a small distance can cause severe contact loads and result in failure of the casing at that location. As a result, the ‘average’ dog-leg severity over an area is important in running torque and drag simulations, but an accurate representation of the maximum expected dog-leg severity is important in modeling casing wear.

Casing Wear Calculation

Earlier studies of casing wear have concluded that most wear is caused by drill string rotation rather than reciprocation. Rotating tool joint against casing interior wears crescent shaped grooves in casing.

To predict the rate of casing wear by rotating drill string tool joint, it is necessary to express the rate of wear in terms of field-measured parameters, which include the mud system, tool joint material, casing material, dog-leg severity, rotary speed and ROP, and the tension along the drill string (torque and drag). Bradley(1975),Bol(1986),Williamson (1985) and Hall(1993, 1994, 2005), and others have all helped to develop methods of calculating casing wear.

The volume of casing wall removed per foot in time t hours is mathematically expressed in the equation below.

$$WV = WF \times SF_{dp} \times \pi \times D_{tj} \times 60 \times N \times t$$

Where:

WV	Casing wear volume per foot, in^3/ft
WF	Casing wear factor, defined as the ratio of friction factor to specific energy, E-10psi^{-1}
SF_{dp}	Side force on drill string per foot, lbf/ft
D_{tj}	Tool joint OD, inch
N	Rotary speed, RPM
t	Rotating time, hour

The definition of wear factor is the ratio of friction factor to specific energy, which is the amount of energy required to remove a unit of steel. An example of some experimentally determined wear factors are shown below in Table 1.

Table 1. List of Experimentally Determined Wear Factors

Selections		Wear Factor (E-10 psi^{-1})
Mud type	Water or Water based, Steel tool joint	0.5 to.40
	Oil based mud, Steel tool joint	0.3 to 5
Tool joint material	Smooth tungsten carbide	8.5
	Very rough tungsten carbide	1625
	Other proprietary casing-friendly hardbanding	1 to 6
Rotating Drill Pipe protector	Pipe protector started with rusted casing	4.1
	Pipe protector with average casing interior	2.1
	Pipe protector after polishing casing	0.06

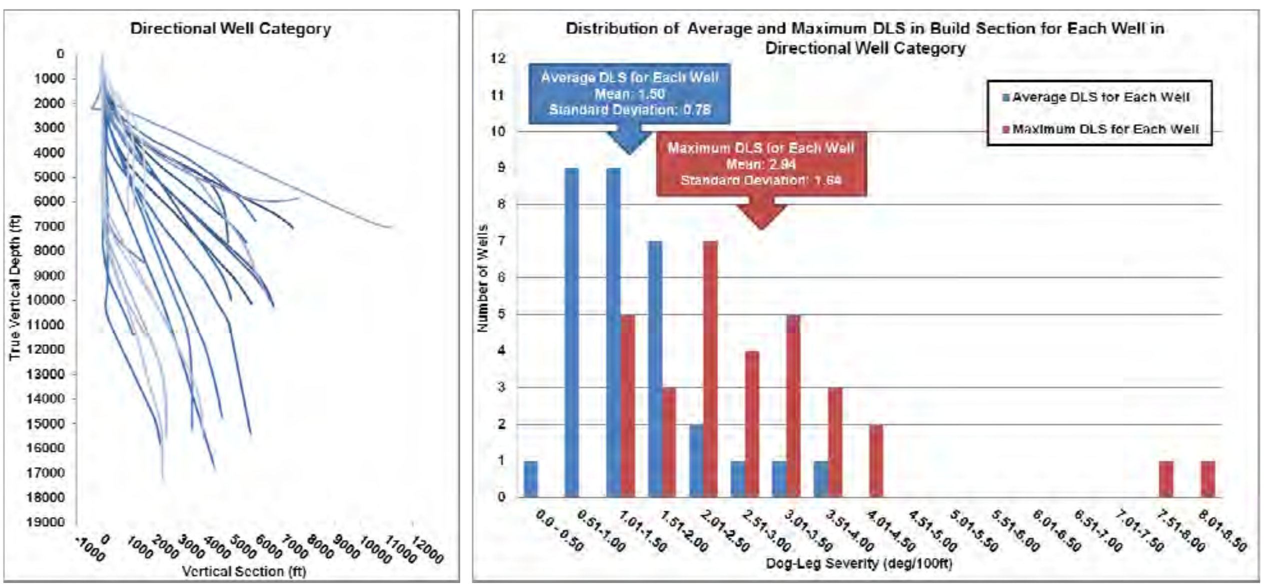
Additional information on the methods for calculating casing wear for the purposes of this paper can be found in the appendix.

Well Survey Database

To provide a statistical understanding of the average and maximum expected dog-leg severity within a variety of wells, surveys from more than a hundred recent directional wells from around the world were collected and entered into a database for analysis. The wells were segregated by category. These categories include horizontal, ERD (extended reach drilling), deepwater, and other directional wells. Horizontal wells are wells that are primarily vertical then horizontal. ERD wells have a reach ratio of 2:1 or greater. Deepwater wells are drilled in approximately 1500ft of water or greater. The directional well category includes wells such as build-and-hold and S-shaped wells. The surveys of each of these wells were then further segregated into vertical, build, and tangent or horizontal sections where possible. Also included in the horizontal well category was a low angle build section for pad-drilled wells that made short build to a 5 to 20 degree inclination angle.

The methodology for this study is to first analyze each section of each well regarding its average dog-leg severity and maximum dog-leg severity. Next, we examined similar wells of the same category and section. This produces the average dog-leg severity for the data group and the average maximum dog-leg severity within the data group, with its associated standard deviations on both parameters. Next, we evaluate the average dog-leg severity and average maximum dog-leg severity of the several data groups in the database using standard statistical methods (Lapin 1990) to determine the cumulative probability at 50%, 90%, and 95% levels (P50, P90, P95).

As an example, all of the wells within the ‘Directional Well’ category are shown in Figure 1. The average and maximum dog-leg severities for the build sections are represented in the histogram chart in Figure 2. As can be seen, the average and maximum dog-leg severity generally fit into a normal distribution patterns. So, the average or mean was calculated for each distribution. For example, when building angle, the average directional well has an average dog-leg severity of 1.5 °/100ft, and a maximum dog-leg severity of 2.94 °/100ft. In this same example, 90% of these wells will have an average and maximum dog-leg severity that is less than 1.28 standard deviations from mean. So, a P90 case will have an average dog-leg severity of 2.50 °/100ft or less, and a maximum dog-leg severity of 5.04 °/100ft or less in the build section.



Figures 1 and 2. Chart showing all wells in the directional category, with a historgram of average and maximum dog-leg severity in the build section for each of these wells.

To calculate the distribution of dog-leg severities within each case, we use the average and maximum expected dog-leg severity to calculate a distribution pattern of dog-leg severities within each section, using the formulas shown in Table 2. These results are shown in Tables 3, 4, 5, and 6. An example of the probability distribution is shown below in Figure 2 for a P90 case. In the P90 case, there is a 90% probability that on a 95ft frequency survey, the average and maximum dog-leg severity will be less than the values listed for each section of the well.

Table 2. Explanation of the Source of the Values Given in Well Statistics Tables.

Probability	Average DLS	Maximum DLS	Expected Standard Deviation of DLS
P50	$\eta_{P50} = \eta$	$M_{P50} = \eta_{max}$	$\sigma_{P50}=(M_{P50} - \eta_{P50}) / \sigma_s$
P90	$\eta_{P90} = \eta + 1.28\ \sigma_\eta$	$M_{P90} = \eta_{max} + 1.28\sigma_{max}$	$\sigma_{P90}=(M_{P90} - \eta_{P90}) / \sigma_s$
P95	$\eta_{P95} = \eta + 1.64\ \sigma_\eta$	$M_{P95} = \eta_{max} + 1.64\sigma_{max}$	$\sigma_{P95}=(M_{P95} - \eta_{P95}) / \sigma_s$

Where:

η Average (arithmetic mean) of the Average DLS values for all wells within a category

σ_{η} Standard deviation of mean DLS values for all wells within a category

η_{max} Mean of the maximum DLS values for all wells within a category

σ_{max} Standard deviation of the maximum DLS values for all wells within a category

σ_s Standard deviations based on the average number of survey points within each section. This represents the number of standard deviations based on a probability that the maximum dog-leg severity is taken from 1 in x, where x is the average number of survey measurements for a section.

Using the example above, for the directional well category, the average build section has 30 survey points, with a η_{P50}=1.50 °/100ft and M_{P50}=2.94 °/100ft. So, a dog-leg severity of 2.94 °/100ft is a 1 in 30 chance in the average well, given that 30 survey points have been taken. So, this equates to this maximum value occurring 1.83 standard deviations away from the mean value. So in this case, the standard deviation, σ_{P50}, would be:

$$(2.94-1.50)/1.83 = 0.78\ °/100\text{ft}.$$

There is a considerable difference in dog-leg severity between the various types of wells. In many of the ERD and deepwater wells, rotary steerable drilling systems are used routinely. In the horizontal and directional well categories, some wells use a rotary steerable BHA, and some wells use a conventional directional BHA. As shown in Figure 3, there is a positive correlation between the average DLS and standard deviation of the DLS in each section of each well, with the standard deviation of the dog-leg severity ranging from about 0.3 to 0.7 times the average dog-leg severity.

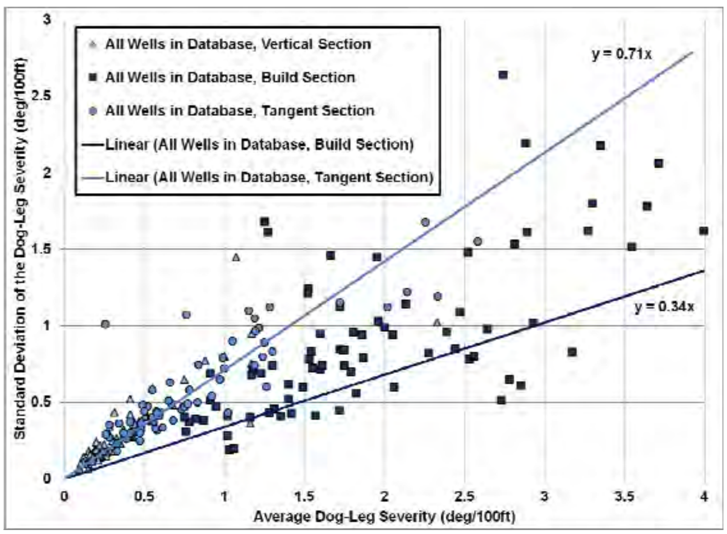


Figure 3. Graph showing the average vs. standard deviation of dog-leg severity for wells used in this database to illustrate that the standard deviation increases with increasing build rate.

Table 3. Horizontal Well Data Group Showing Dog-Leg Severity (°/100 ft) in Various Sections of the Wells at Various Confidence Levels

Confidence Levels	Vertical Section		Build Section		Horizontal Section		Low Angle Build	
	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
P50	0.32	0.45	9.96	2.65	1.53	1.87	1.37	1.29
P90	0.49	0.91	14.53	4.63	2.26	3.38	2.01	1.73
P95	0.53	1.03	15.81	5.19	2.47	3.81	2.20	1.86

Table 4. Deepwater Well Data Group Showing Dog-Leg Severity (°/100 ft) in Various Sections of the Wells at Various Confidence Levels

Confidence Levels	Vertical Section		Build Section		Tangent Section	
	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
P50	0.24	0.35	1.57	1.02	0.42	0.81
P90	0.37	0.64	2.58	1.78	0.59	1.36
P95	0.41	0.73	2.87	1.99	0.63	1.52

Table 5. ERD Well Data Group Showing Dog-Leg Severity (°/100 ft) in Various Sections of the Wells at Various Confidence Levels						
Confidence Levels	Vertical Section		Build Section		Tangent Section	
	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
P50	0.51	0.41	2.18	1.47	0.75	0.75
P90	1.29	1.03	3.33	2.44	1.37	1.21
P95	1.50	1.21	3.65	2.71	1.55	1.34

Table 6. Directional Well Data Group Showing Dog-Leg Severity(°/100 ft) in Various Sections of the Wells at Various Confidence Levels						
Confidence Level	Vertical Section		Build Section		Tangent Section	
	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
P50	0.39	0.43	1.50	0.78	0.61	0.75
P90	0.81	0.81	2.50	1.38	0.91	1.20
P95	0.92	0.91	2.78	1.55	1.00	1.33

Effect of Rotary Steerable vs. Conventional Directional BHA on Dog-Leg Severity

Difficulty was encountered in differentiating wells with various BHA types within the database. For example, horizontal wells are drilled with different BHA types in different sections of the well. This is in contrast to deepwater wells that are most often entirely drilled with some type of Rotary Steerable System (RSS). To examine the effect of RSS versus conventional directional methods, two wells drilled in the Gulf of Mexico were examined. The wells were similar in shape, with a build and hold shape at 60 to 70° inclination. Measured depth was adjusted to allow an overlay for comparison. As seen in Figure 4 and Table 7, the average build rate is similar, but overall the standard deviation in dog-leg severity was much greater using the conventional directional BHA. Therefore, in the vertical and horizontal or tangent section of most directional wells, there will be an increase in the standard deviation and maximum dog-leg severity when using a conventional directional BHA.

These results agree with those of Weijermans et al (2001). They found that the standard deviation of dog-leg severity in wells drilled with RSS was approximately half that of a conventional directional BHA for a given average build rate.

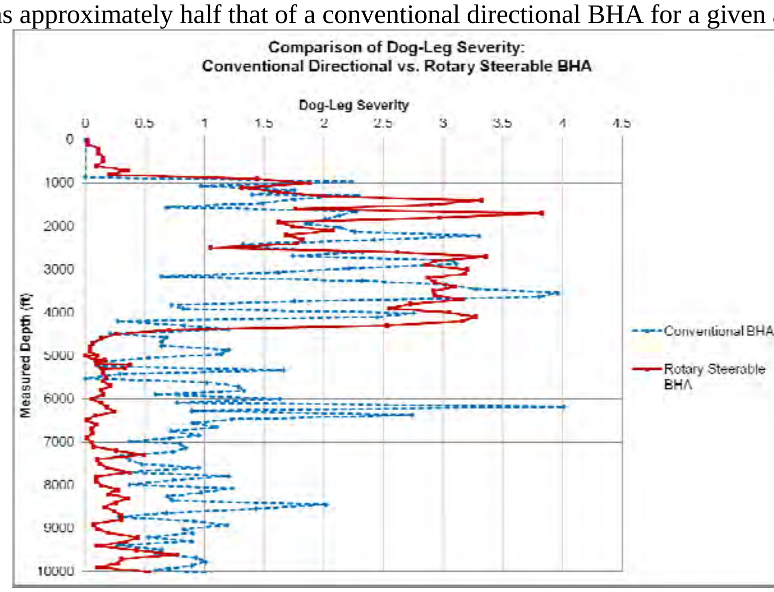


Figure 4. Graph comparing the dog-leg severity of a conventional directional BHA vs. rotary steerable BHA in similar Gulf of Mexico wells.

Table 7. Comparison of Dog-Leg Severity Statistics of Conventional vs. Rotary Steerable BHA (°/100 ft)				
	Build		Tangent	
	Conventional BHA	Rotary Steerable	Conventional BHA	Rotary Steerable
Average	2.10	2.52	0.88	0.20
Standard Dev.	0.85	0.72	0.61	0.16
Maximum	3.96	3.83	4.01	0.77

Effect of Survey Accuracy and Survey Station Frequency on DLS

When using actual surveys to model casing wear, the effect of the frequency of the survey readings on the accuracy of the mode was considered. Although it would seem that more measurements in a well interval would improve the accuracy of the modeling of the dog-leg severity, these casing wear and torque drag models rely on the rate of change in direction, or dog-leg severity of the wellbore. A change in direction over a very small distance can result in very large values for dog-leg severity. Therefore, if survey points are too close together, the 'noise' coming from sources, such as the resolution and accuracy of the survey device, makes it difficult to discern actual dog-legs within the data noise. Gabris and Hansen (1988) showed that there can be a variation in the accuracy of survey measurements taken in the same wellbore with difference devices.

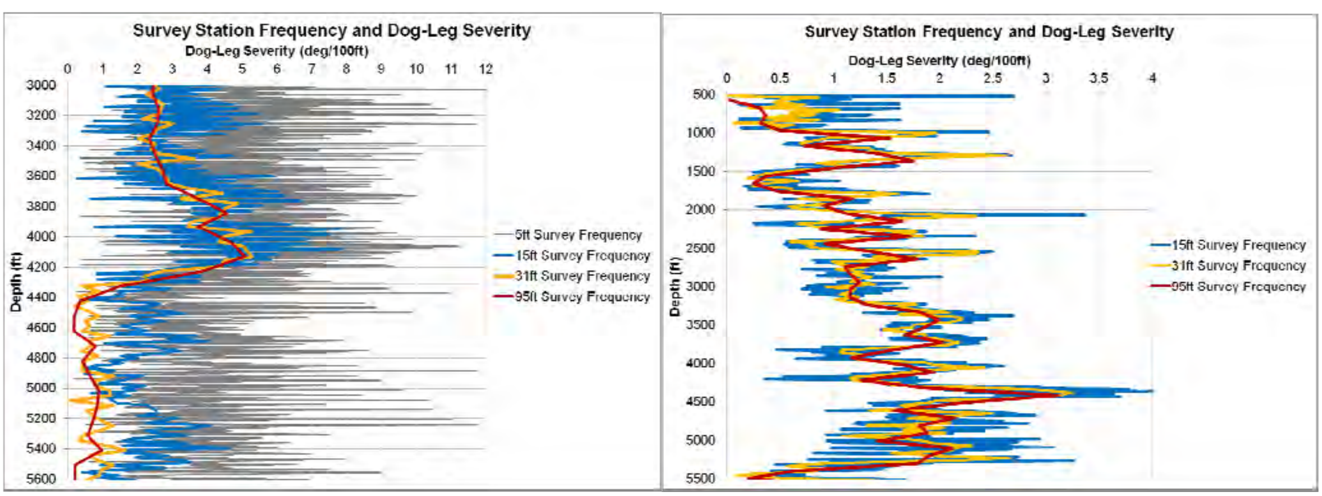
As an example, if surveys are taken at 5ft intervals using a typical MWD or Gyro device with an accuracy of +/- 0.1° for both inclination and azimuth, the resulting error band would be 1.7 °/100ft, completely masking most real dog-legs within the well. But, if that same tool were making measurements every 31ft, then the error band is only 0.3 °rees/100ft. The table below shows the error band created when taking surveys at various intervals. As a general rule, surveys taken at intervals less than 15ft result in too much noise to accurately represent the actual wellpath. Table 8 shows the correlation between the survey device and the possible error band in the dog-leg severity.

Table 8. Error in Dog-Leg with Varying Survey Station Frequency. (°/100ft)

	Survey Station Frequency			
Survey Accuracy	5 ft	15 ft	31 ft	95 ft
+/- 0.1 °	1.7	0.6	0.3	0.1
+/- 0.25 °	4.2	1.4	0.7	0.2
+/- 0.5 °	8.5	2.8	1.4	0.5

Conversely, if the surveys are taken too far apart then the survey will ignore or underestimate dog-legs that are normally present in the well. As an example, Figures 5 and 6, along with Table 9 compares dog-leg severities taken from the same survey sampled at varying intervals. In Figure 5 shown on the left, the survey was taken using a gyro through the drill pipe, so the sag in the pipe is visible as a large variability in dog-leg severity at 5ft intervals. In Figure 6, the survey on the right is a gyro survey run in the casing. For the 5ft survey, too much noise is generated by the survey tool and the periodic sag in the pipe. When viewed at 15ft intervals, some of the same noise is still present, but short period dog-legs are better defined. In both cases, when the surveys are viewed at 95ft intervals, short interval dog legs are not clearly defined.

In most cases, surveys taken every 31ft provide a good balance in producing a reasonable picture of actual dog-legs within the wellbore without too much noise from survey tool accuracy. With surveys taken every 95ft, the average dog-leg appears to be similar to the build section of surveys taken at a frequency of 15ft to 31ft. In the tangent section, the higher resolution surveys appear to do a better job of finding the smaller period dog-legs, so the standard deviation increases.

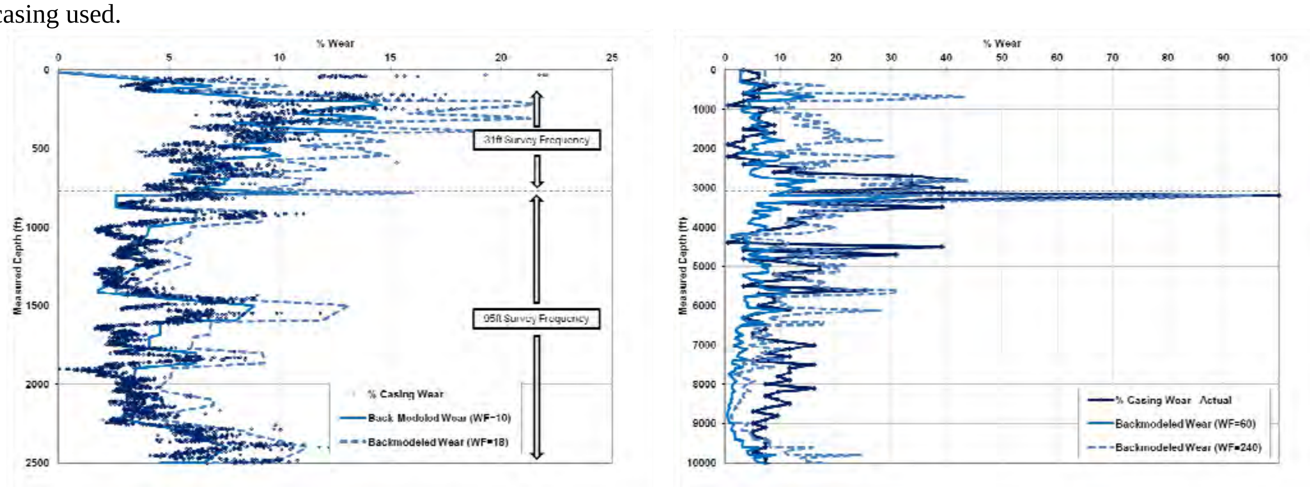


Figures 5 and 6. These graphs show the dog-leg severity of a high resolution survey of 2 wells sampled at varying survey intervals.

Table 9. Average and Standard Deviation of the Example Wells Shown Above (°/100 ft)						
	Example Well 1, RSS				Example Well 2, RSS	
	Build Section		Tangent Section		Build Section	
Survey Frequency	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation
5ft	5.15	2.72	3.96	2.40	N/A	N/A
15ft	3.40	1.91	1.99	0.95	1.47	0.8
31ft	3.26	1.02	0.80	0.41	1.39	0.67
95ft	3.29	0.96	0.50	0.30	1.35	0.62

Back-model of Casing Wear Logs

Casing wear logs were available for several of the wells within the database. Back-models were run on several of these wells using actual surveys taken every 95-100ft, unless otherwise specified. All the modeling parameters were set to match the actual parameters for each well so that the drill pipe, casing, RPM, and ROP parameters were as close as possible to the recorded values. Then, the wear factor was adjusted to achieve the best possible fit to the average wear as well as maximum measured wear. Examples are shown below in Figures 7 and 8. A summary of the results of these back-models is shown in Table 10. Some of these back-models were taken from USIT (ultrasonic imager tool) logs which give a precise measurement of wall thickness, while others were taken from multi-finger caliper logs, which give a reading of the inside geometry of the casing. In the second set of wear data, the percent (%) wear is inferred from nominal wall thickness values for the type of casing used.



Figures 7 and 8. Casing wear back-model results for a S-shape land well in the western US, and a horizontal well in North Dakota. Notice that in both of these wells, the maximum wear is far greater than predicted when the average wear is matched up.

Table 10. Comparison of Back-Modeled Wear Factors					
Well Type	BHA Type	Location	Mud Type	Wear Factor to Match Average Wear, E-10psi^{-1}	Wear Factor to Match Maximum Wear, E-10psi^{-1}
Horizontal	Conventional	North Dakota	OBM	60	240
Horizontal	Conventional	North Dakota	OBM	30	60
Horizontal	RSS	Texas	OBM	20	20
Horizontal	Conventional	Oklahoma	OBM	10	20
Deepwater	RSS	Gulf of Mexico	SBM	2-5	10
Deepwater	RSS	Gulf of Mexico	SBM	7	7
Deepwater	RSS	Gulf of Mexico	SBM	3	10
S-Shape Directional	RSS	Colombia	OBM	1.5	2
S-Shape Directional	RSS	Colombia	OBM	1.5	2.5
S-Shape Directional	RSS	Colombia	OBM	1.5	3
S-Shape Directional	RSS	Texas	WBM	5	10
S-Shape Directional	Conventional	Rockies	WBM	10	18

The horizontal wells in this study required relatively high wear factors from 20 to 100 E-10psi^{-1}. This wear factor is much greater than other wells. The high wear rate could be due to several factors that are particular to horizontal drilling.
First, in horizontal wells, drill pipe wear is often a serious issue in the horizontal sections, so hardbanding is re-applied frequently, and case is not taken to grind the hardbanding flush with the pipe. Raised hardbanding decreases the contact area and significantly increases the contact pressure between the drill pipe and casing. This hardbanding can also be fairly aggressive as the drill pipe suppliers attempt to protect their investment at the cost of wear to the casing. Another issue is that

in horizontal wells, devices are often used that use rotation or vibration to break static friction while slide drilling, but also cause relative motion that could increase casing wear when slide drilling. Horizontal wells also have a relatively steady contact force throughout the horizontal section because True Vertical DepthTVD is being held constant. And finally, buckling plays an important role in increasing wear lower in the well due to increased side force from compression in the drill pipe.

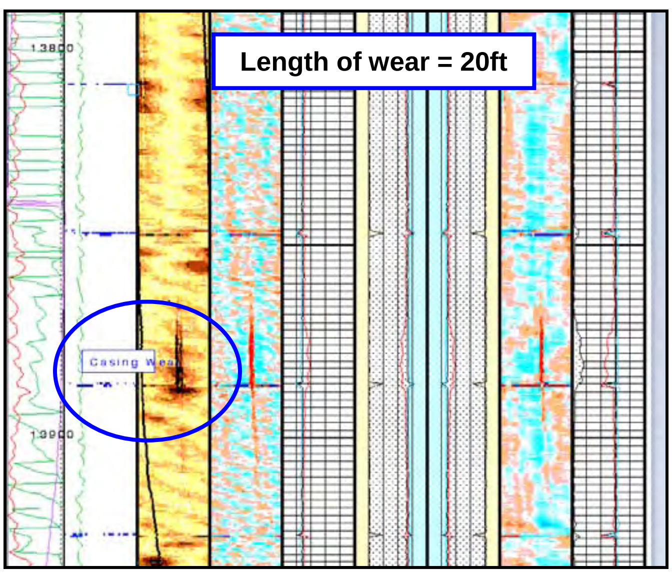
The deepwater wells examined in this project show a wear factor of 2 to 10 E-10psi^{-1}. This relatively low wear factor is likely be due to a combination of factors, including: high strength casing, premium casing-friendly hardbanding, a lower degree of dog-leg severity because of extensive use of rotary steerable BHA, and also the use of premium synthetic oil-based mud. All of these factors generally result in lower friction and wear on the casing. In the deepwater wells analyzed, there were often one or two small areas that were 10 to 50ft in length that required a wear factor of 7 to 10x10^{-10} psi to match the modeled wear to actual wear values. These were usually located at the mudline, or near and within the formation salt strata. All of the deepwater wells universally used rotary steerable systems, so while dog-leg severity is kept lower than some of the other well types, because of the use of rotary steerable systems, they also drill at high RPM which can increase the total amount of revolutions.

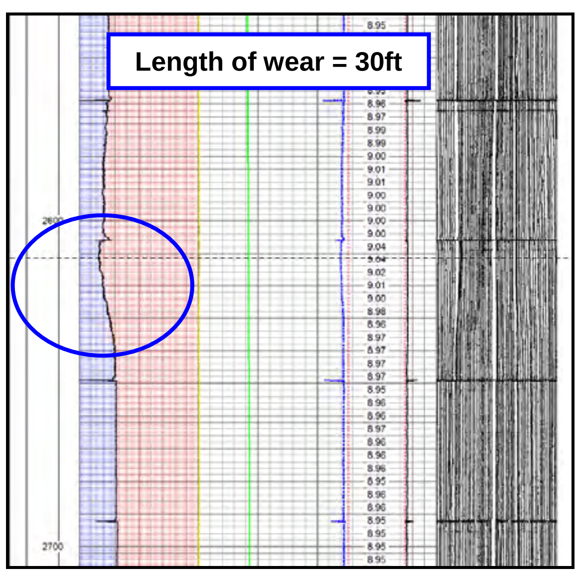
The directional well category used a variety of casing, drilling systems, and ROP, so the wear factor ranged from 1.5 to a high of 18 E-10psi^{-1}. In general, the lower wear factors were seen in wells with casing-friendly hardbanding, high strength casing, oil based mud, and rotary steerable systems.

Due to the relative scarcity of casing wear logs, the back-modeled wear factors should be used as a guideline. The sample size of casing wear back-models was not sufficient for the purposes for determining a statistical distribution of casing wear factors. Future work will focus on increasing the size of the casing wear back-model database.

It is important to note that in most of these cases, the wear factor could be adjusted so that the predicted and actual wear were approximately coincident, however there often existed short-distance ‘spikes’ in wear greater than predicted. As shown below in Figures 9 and 10, this is a result of wellbore curvature that is shorter than the survey interval. This results in dog-leg severity that is underestimated by an amount related to the ratio of the length of the dog-leg severity divided by the survey station interval. Examples of acute casing wear over short intervals are shown in the casing wear logs in Figures 9 and 10.

Note that the casing wear log shown in Figure 8 is from a deepwater Gulf of Mexico well drilled using synthetic oil-based mud and a rotary steerable BHA; hence, even when drilling with the latest in technology, short distance casing wear is possible. This could be caused by by conditions such as a result of drilling between two different formations, such as when drilling near salt, or at sidetrack points where a whipstock can cause an abrupt change in direction, or could be caused by buckled casing that would not otherwise show up in a survey taken prior to running the casing.





Figures 9 and 10. Examples of casing wear logs showing acute, short distance wear.

New Statistically-Based Tortuosity Model

Using the statistical data gathered from the well surveys, a new tortuosity model was created so that the distribution of dog-leg severity in the tortured survey matches expected values based on the probability level, section, and well type being analyzed.

In this new model, tortuosity is applied so that dog-leg severity is varied in a distribution pattern based on the statistical data gathered from the well database. Tables 3 to 6 are used as a basis for the average (η) and standard deviation (σ) in the equations below, with the exception that in a build or drop section, the planned build or drop rate is used as the average value. For build or drop values far outside the statistical values, a standard deviation that is 0.3 to 0.7 times the average expected build rate is permissible, as shown in Figure 3.

The tortuosity model must have zero as a lower bound, because negative values for dog-leg severity are not allowed, so a normal distribution could not be used. As shown in the example in Figure 11, a gamma distribution provided good approximation to distributions of actual dog-leg severity data.

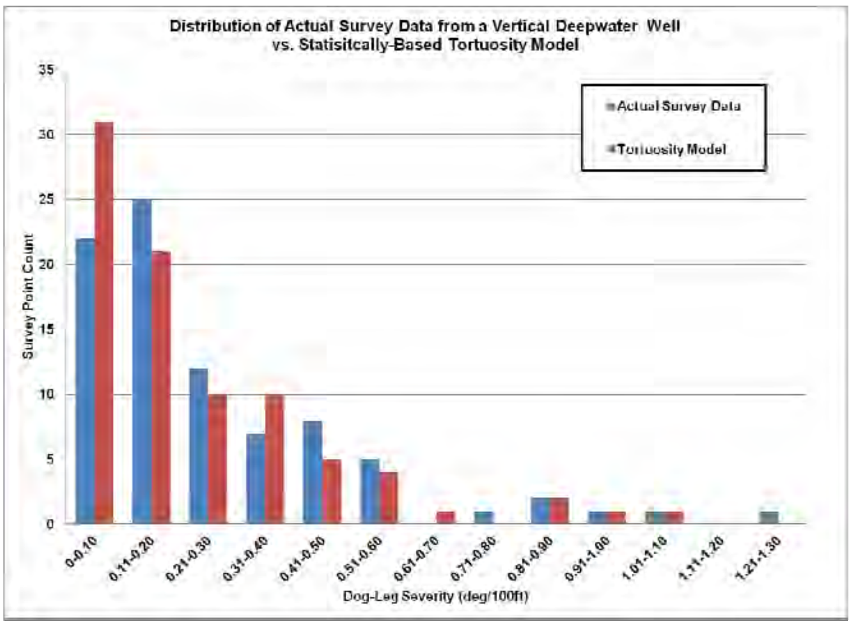
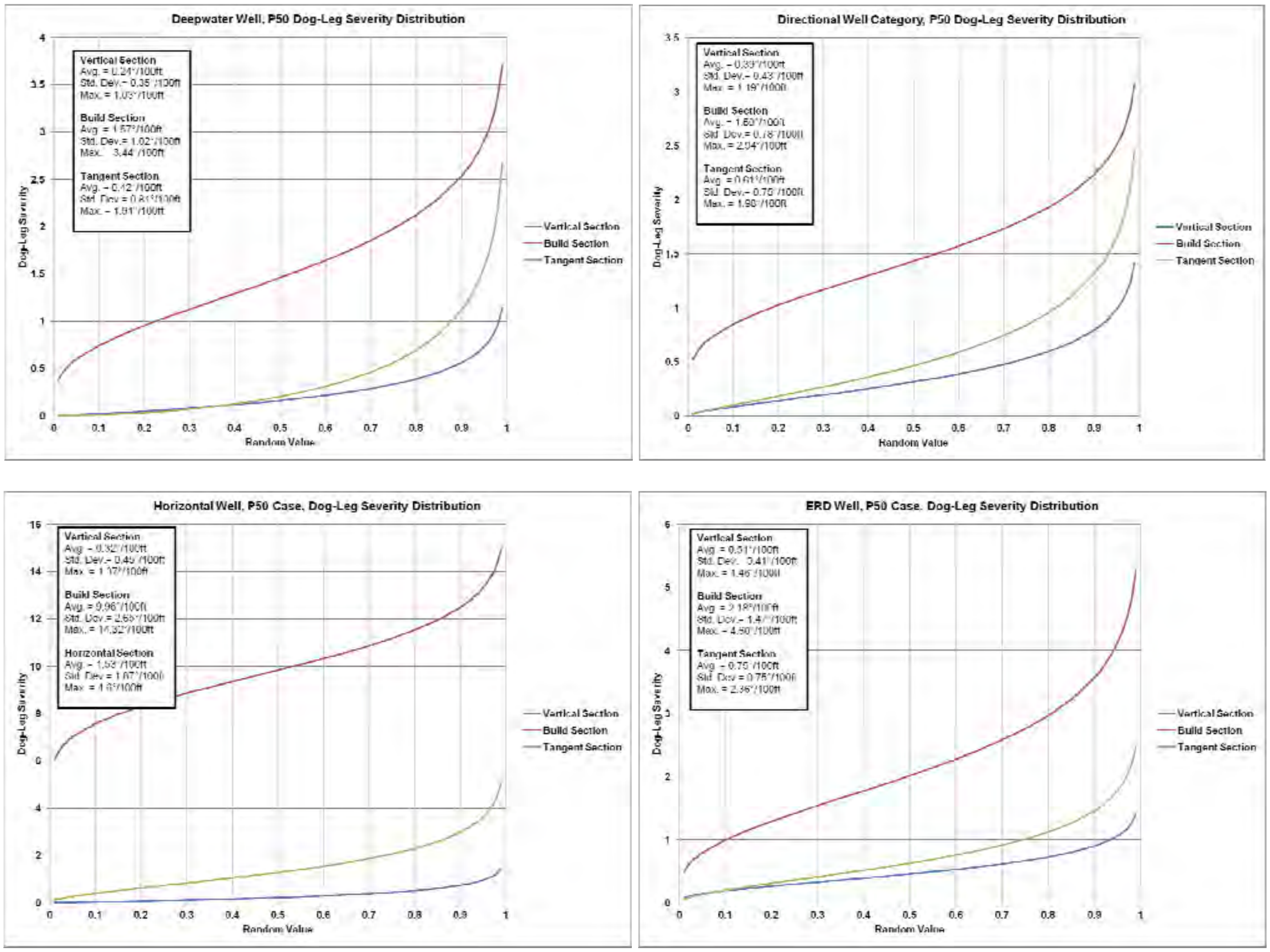


Figure 11. Comparison of the distribution of dog-leg severity of an actual vertical deepwater well and the results from a tortuosity simulation using the gamma distribution model described in this paper.

A mathematical description of a gamma probability distribution is given in the appendix, but in general, gamma distributions are represented by two parameters, α and β, that define the shape of the distribution curve. In general, larger values of α produce a distribution that is less skewed, whereas larger values of β produce a flatter curve. The values that were found to provide a good fit for the gamma distribution function over the range of expected dog-leg severities are listed below:

$$\alpha = \frac{\mu}{\beta} \qquad \beta = \frac{\sigma^2}{2\mu}$$

Examples of the gamma distribution results for dog-leg severity are shown for P50 case wells in Figures 12-15. In the tortuosity model, a random value is generated, ranging from 0 to 1, and the computer calculates the inverse gamma function to return the dog-leg severity based on the average (η) and standard deviation (σ) values provided. This dog-leg severity is then translated into a tortured survey that best fits the planned well trajectory.

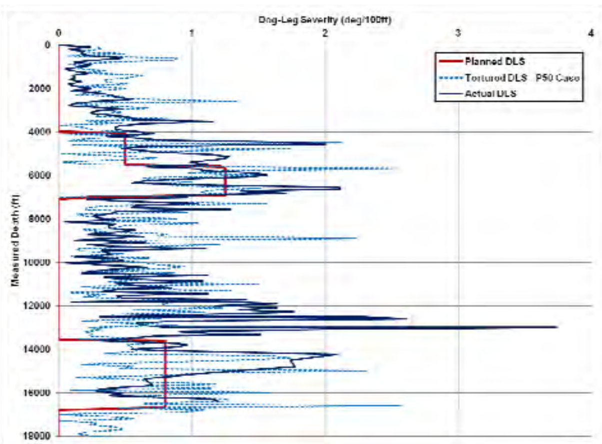


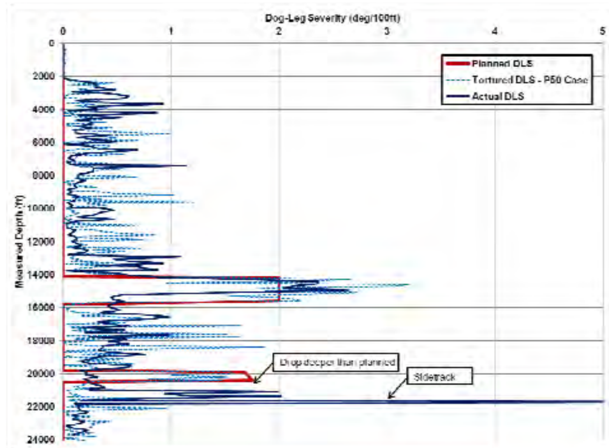
Figures 12-15. Graph showing distribution of dog-leg severity vs. the randomly generated value for the P50 case for both the deepwater and directional well category.

One important addition to the model is to include corrections for analyzing the vertical or low inclination tangent sections of wells drilled with a conventional directional BHA. In these cases, it is necessary to account for some of the dog-legs created by slide drilling corrections that would otherwise be unaccounted for in the directional survey. To do this, zones are inserted with dog-legs represented by the "Low Angle Build" column in the horizontal well statistical Table 3, or the "Build" column in the deepwater, ERD or directional well found in Tables 4, 5, and 6. Generally these dog-leg severities represent the build rate created by the directional BHA used when correcting back to vertical. This magnitude of dog-leg severity, in the range of 3 to 6 deg/100ft, are added to as-drilled surveys taken at intervals of more than 30ft to account for short period dog-legs that do not show up in an as-drilled survey. As an example, when drilling a horizontal well, often the surface casing is drilled with a vertical packed hole BHA, so the hole below the surface casing would include some of the corrections mentioned above, perhaps 2 survey points each 1500ft.

An average well can be analyzed using the values in the P50 case. The P90 and P95 represent more severe cases with a decreasing probability of occurrence, but should be considered in planning and risk assessment.

Two examples are shown below in Figures 16 and 17 compare the Statistically-Based Tortuosity with the actual as-drilled surveys. Figure 16 shows an S-shaped well drilled in Texas. Figure 17 is an S-shaped deepwater well drilled in the Gulf of Mexico. The graphs compare the planned, tortured P50 case, and actual dog-leg severity. As you can see, the actual dog-leg severity matches closely to the dog-leg severity predicted by the Statistically-Base Tortuosity Model.





Figures 16 and 17. Comparison between planned, actual, and tortured surveys using the Statically-Bsed Tortuosity Model.

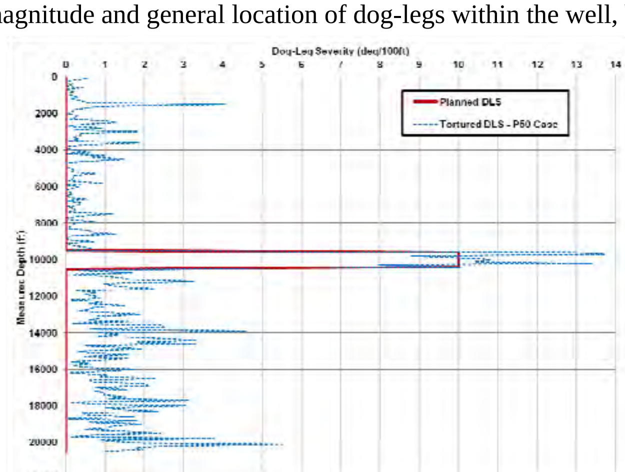
When running casing wear analyses, wear factors listed below in Table 10 shows a range of possible wear factors based on back-model average casing wear patterns. To predict the maximum wear within the casing, these values should be multiplied by a factor of 2. In general, wells drilled using flush, casing-friendly hardbanding and synthetic oil-based mud will result in values on the lower side of the range shown in Table 10.

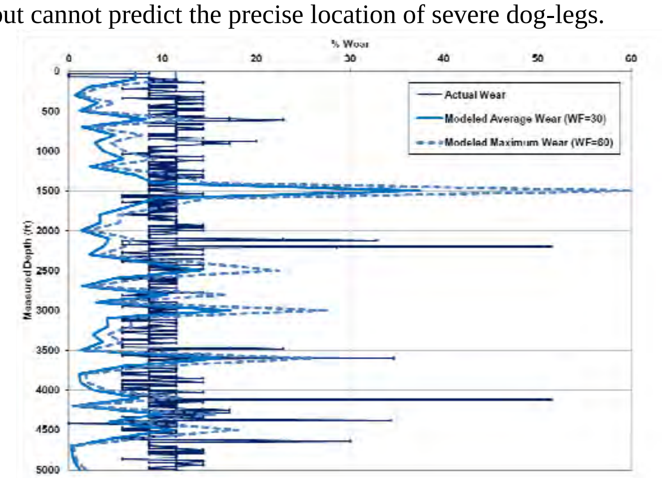
Table 10. Suggested Wear Factors Based on Casing Wear Backmodels

Well Type	Wear Factor Range to Model Average Wear E-10psi^{-1}	Wear Factor Range to Model Maximum Wear E-10psi^{-1}
Horizontal	10 - 60	Use a value 2 to 4(where is justification for 4) times the average wear factor to determine maximum wear.
Deepwater (using RSS)	1.5 - 7	
ERD	1.5 - 10	
Other Directional Wells	1.5 - 10	

As an example of the use of this Tortuosity model, a typical horizontal well drilled in the Bakken Formation of North Dakota was modeled. The example well used 7 inch, 26ppf casing to 7000ft, with 7 inch, 32ppf casing to 11000ft. A conventional directional assembly was used with 4 inch drill pipe. The well is drilled with a 10000ft TVD and 10000ft VS. The P50 'average well' case was examined, using a moderate wear factor of 30 x10^{-10}/psi to model average wear, and 60 x10^{-10}/psi to model maximum wear. The dog-leg severity of the proposed and tortured survey is shown in Figure 18 and the resulting wear is shown in Figure 19.

In the P50 case for the Bakken well, using a wear factor of 60 x10^{-10}/psi, the maximum expected wear is 35-40% of the casing thickness. In the P90 case, with the same wear factor, the maximum predicted wear is 60-70% of the casing thickness. These results were compared with a casing wear log from another North Dakota well not included in the database. The results from the actual well are shown in Figures 18 and 19. The results compare well with the results predicted by the Statistically-Based Tortuosity Model, shown as a dotted line in the figures below. In general, the model is accurate in the magnitude and general location of dog-legs within the well, but cannot predict the precise location of severe dog-legs.





Figures 18 and 19. Example of a model of a typical Bakken North Dakota well, showing the tortured survey dog-leg severity, and resulting casing wear.

Casing Wear Mitigation Using Non-Rotating Protectors

Moore et al (1996) demonstrated that Non-Rotating Protectors (NRP) help to reduce casing wear. Several wells in the database used NRP protect the casing in the areas of highest calculated contact force. These wells were analyzed to determine the effect of NRP on casing wear.

In one example, the well was re-drilled through a window cut lower in the well. The original wellbore was drilled without protectors, and a sidetrack was drilled with 6 million revolution using NRP to cover most of the casing from 8000-12000ft MD. Casing wear logs were run before and after drilling the sidetrack. These logs are shown below in Figure 20 below, indicating that there was no additional wear.

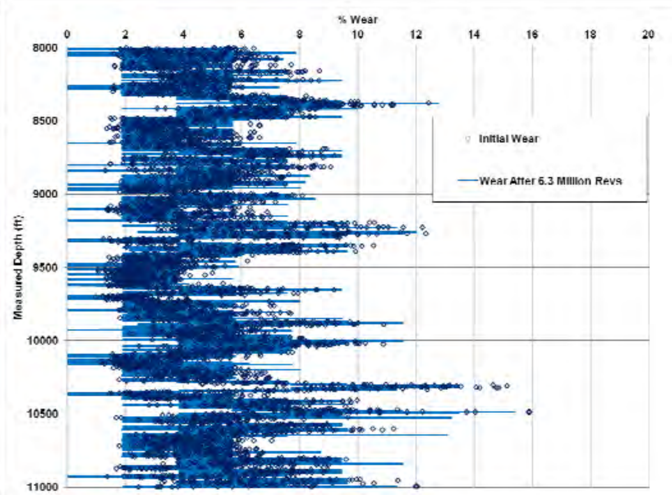
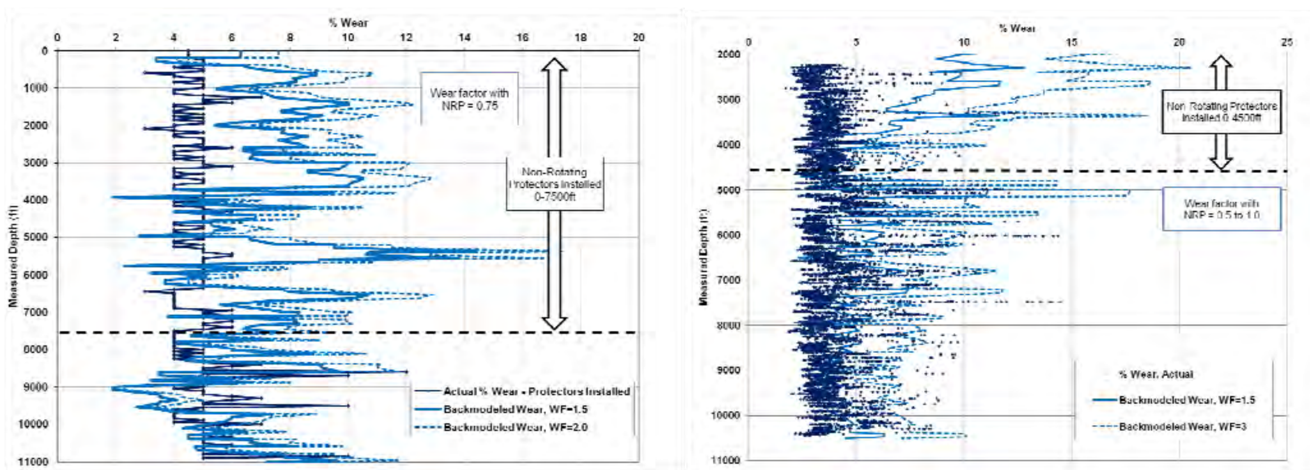


Figure 20. Comparison of casing wear after initial wellbore without NRP use, then after a sidetrack requiring over 6 million revs. With the use of NRP, there is no discernible increase in wear even after 6 million revs.

In other wells in the database, NRP were installed in high side force areas of s-shape wells shown in Figures 21 and 22. In both of these wells, the entire string was not covered. The wells were back-modeled to calculate the average wear factor in the area without protectors. Then the measured wear was compared with the actual wear with the use of NRP. As seen in Figures 16 and 17 below, the protectors were effective at preventing wear to the casing. The wear factor in the areas with NRP installed was reduced from 1.5 to 3 E-10psi^{-1}down to 0.5 to 1.0 E-10psi^{-1}.



Figures 21 and 22. Casing wear logs from two wells drilled with Non-Rotating Protectors to help protect a portion of the casing.

Conclusions

The statistical examination of a database of over 100 wells provides insights into assessing casing wear risk. The conclusions from this examination are the following:

- The well category type, including horizontal wells, deepwater wells, ERD wells, and directional wells, affects the dog-leg severity and thus affects casing wear.
- The variance in dog-leg severity increases with build rate.
- Rotary steerable systems generally produce less variance in dog-leg severity than conventionally drilled wells.
- Survey frequency affects the error of the measured dog-leg severity. Generally, measurements at less than 15 ft intervals produce excessive variance in dog-leg severity measurements and intervals of about 95 ft or more significantly underestimate dog leg severity.
- A statistically-based tortuosity model is presented that appears to more accurately predict actual dog-leg severity for the purposes of modeling casing wear and assessing casing wear risk.
- Most wells are not surveyed at a frequency required to accurately depict acute, short distance dog-legs within the well, and surveys taken while drilling would not measure deviations caused by buckled casing or inadequate support from cement. As a result, wells often require a wear factor twice the average value to predict areas of maximum casing wear.
- Often, back-modeled wear factors are greater than laboratory test results would suggest, particularly in horizontal wells.

References

Bol, G.M., October 1986, Effect of Mud Composition on Wear and Friction of Casing and Tool Joints, SPE Drilling Engineering
Bradley, W., and Fontenot, J., February 1975, The Prediction and Control of Casing Wear, SPE 6399
Chan, A. et al, August 2008, Evolution of Innovative Test Methodology for Evaluation of Hardfacing Materials in both Cased and Open Hole Environments, IADC/SPE Asia Pacific Drilling Technology Conference in Jakarta, SPE/IADC 115206
White, J., and Dawson, R., March 1987, Casing Wear: Laboratory Measurements and Field Predictions, SPE Drilling Engineering
Gaynor et al, March 2001, Tortuosity versus Micro-Tortuosity - Why Little Things Mean a Lot, SPE/IADC 67818
Gabris, P.M., and Hansen, R.R., Martch 1988, A Field Comparison of Directional Accuracy of MWD in Comparison with Six Other Survey Tools, SPE/IADC 17214
Gaynor et al, October 2002, Quantifying Tortuosities by Friction Factors in Torque and Drag Model, SPE Annual Technical Conference in San Antonio, SPE 77617
Lapin, L. ed. 1990, Probability and Statistics for Modern Engineering, Second Edition, PWS-Kent Publishing Company
Lubinski, .A, Maximum Permissible Dog-Legs in Rotary Boreholes, Journal of Petroleum Technology, Feb 1961
Lubinski, A., and Williamson, J. Usefulness of Steel or Rubber Drillpipe Protectors, Journal of Petroleum Technology, April 1984
Moore et al, May 1996, Reduction of Drill String Torque and Casing Wear in Extended Reach Wells Using Non-Rotating Drill Pipe Protectors, SPE Western Regional Meeting in Anchorage, SPE 35666
Hall, R.W., and Malloy, K.P., April 2005, Contact Pressure Threshold: An Imporant New Aspect of Casing Wear, SPE Productions and Operations Symposium in Oklahoma City, SPE 94300
Hall. R.W. et al, February 1994, Recent Advances in Casing Wear Technology, IADC/SPE Drilling Conference in Dallas, SPE 27532
Hall R.W. et al, February 1993, Laboratory Casing Wear Tests, Paper No. 93-PET-3 Energy Sources Technology Conference
Samuel, G.R., et al, February 2005, Tortuosity Factors for Highly Tortuous Wells: A Practical Approach, SPE/IADC Drilling Conference in Amsterdam, SPE/IADC 92565
P.Weijermans, et al, March 2001, Drilling with Rotary Steerable System Reduces Wellbore Tortuosity SPE/IADC 67715
Williamson, J.S. September, 1985 Casing Wear: The Effect of Contact Pressure, Journal of Pet. Tech., SPE 10236

Appendix: Casing Wear Calculation

Earlier studies of casing wear have concluded that most wear is caused by drill string rotation rather than reciprocation. Rotating tool joint against casing interior wears crescent or "moon-shaped" grooves in casing.

To predict the rate of casing wear by rotating drill string tool joint, it is necessary to express the rate of wear in terms of field-measure parameters, which include:

- Mud system (abrasiveness)
- Tool joint material
- Casing wear resistance
- Dog-leg severity
- Rotary speed and ROP
- Tension along the drill string (torque and drag)

The volume of casing wall removed per foot in time t hours is mathematically expressed in the equation:

$$WV = WF \times SF_{tj} \times SD \qquad (1)$$

The equaion to calculate the sliding distance traveled by the tool joint is:

$$SD = \pi \times D_{tj} \times 60 \times N \times t \times \frac{L_{tj}}{12 \times L_{dp}} \qquad (2)$$

Calculating the side force per tool joint is given by the equation:

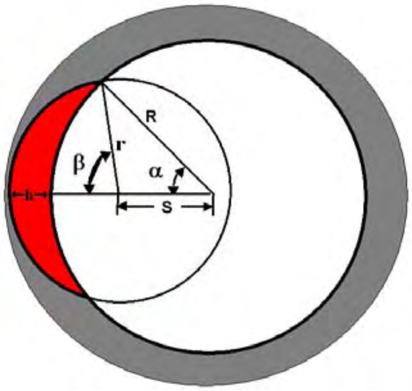
$$SF_{tj} = \frac{SF_{dp} \times L_{dp} \times 12}{L_{tj}} \qquad (3)$$

Combining Eq.(1), (2) and (3) will result in the following casing wear volume equation:

$$WV = WF \times SF_{dp} \times \pi \times D_{tj} \times 60 \times N \times t \qquad (4)$$

Wear Geometry

A typical wear groove is shown in the following figure:



The relationship between wear depth and casing wear volume is:

$$WV = 12(\beta r^2 + 2\sqrt{P(P-R)(P-r)(P-S)} - \alpha R^2) \qquad (5)$$

S = R - (r - h), inch

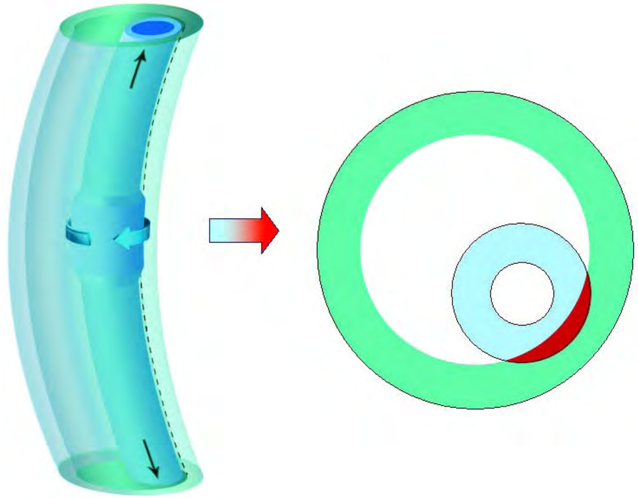
P = (R + r + S) / 2, inch

$$\cos\alpha = (R^2 + S^2 - r^2)/2RS$$

$$\beta = arctg(\frac{R \times \sin\alpha}{R \times \cos\alpha - S})$$

Wear Factor

Many researchers, including Bradley(1975),Bol(1986),Williamson (1985) and Hall(1993, 1994, 2005),have concluded that the volume of steel removed from casing is proportional to frictional work done by the tool joint rotating against the casing.



The definition of wear factor is the ratio of friction factor to specific energy, which is the amount of energy required to remove a unit of steel. The unit for wear factor is E-10 psi^{-1}. Therefore, when a wear factor is reported as 8, the actual value used in casing wear calculation is 8E-10 psi^{-1}.

Many experiments were conducted to find the casing wear factors under different mud system, tool joint material, casing interior, drill string protectors. Among them, Maurer Engineering Inc. conducted a joint-industry project DEA-42. It was reported that more than 300 laboratory tests were performed under DEA-42 to determine the wear factors for various drilling conditions. The casing wear testing machine consisted of a device for rotating a tool joint sample, approximately 5 inches long, against a casing sample at a set RPM and side load. The wear was recorded at pre-determined intervals and used to derive a wear factor.

In the SPE Paper "Recent Advances in Casing Wear Technology", Dr. Russell Hall, et al, illustrates some of the variation of wear factor vs. mud additive and/or lubricants, pipe protectors, etc.

Gamma Distribution

The gamma distribution is an effective distribution for cases where the values are non-negative and skewed. The gamma probability density function (Lapin, 1990) is given by the equations:

$$f(x;\alpha,\beta) = \frac{\beta^{\alpha}}{\Gamma(\alpha)} x^{\alpha-1} e^{-\beta x} \qquad \Gamma(\alpha) = \int_0^{\infty} x^{\alpha-1} e^{-x}\,dx \;\; for\ \alpha > 0$$

Spreadsheet and statistical software packages have the ability to output gamma distributions given the variables α and β.

Abbreviations

D_{tj}	Tool joint OD, inch
h	Wear depth, inch
L_{tj}	Total length of tool joint, inch
L_{dp}	Length of each joint of pipe, feet
N	Rotary speed, RPM
r	Tool joint outer radius, inch
SF_{tj}	Side force on the tool joint, lbf/in
SF_{dp}	Side force on each joint of pipe, lbf/ft
SD	Sliding distance, inch
t	Rotating time, hour
WF	Casing wear factor, defined as the ratio of friction factor to specific energy, E-10psi^{-1}
WV	Casing wear volume per foot, in^3/ft
R	Casing inner radius, inch