ABSTRACT

The present invention includes an apparatus and method including a torsional baffle to protect a top drive or rotary table assembly of a drilling rig from torsional vibrations caused from vibration inducing drilling conditions. The torsional baffle includes sufficient torsional impedance to prevent the drilling vibrations from damaging the internal workings of the rotary table or top drive apparatus.
TOP DRIVE TORSIONAL BAFFLE APPARATUS AND METHOD

BACKGROUND OF THE INVENTION

[0001] The present invention generally relates to apparatus and methods to reduce the detrimental effects of bit-bounce and stick-slip vibrations on a top drive drilling assembly. More particularly, the invention relates to a high-impedance torsional baffle located below the top drive drilling assembly atop a drillstring. More particularly still, the invention relates to a cylindrical or disc-shaped baffle located below a top drive drilling assembly to counteract torsional vibrations that would otherwise damage the top drive.

[0002] In typical oilfield drilling operations, a drive system rotates a string of threadably connected pipes called a drillstring at a proximal end. Typically, a bottom hole assembly (BHA) including a drill bit resides at the distal end of the drillstring and is used to drill the well deeper. Lubricating fluid, called drilling mud, is pumped down an internal bore of the drillstring to lubricate and cool the drill bit as well as remove cuttings from the well. The slurry of drilling mud and cuttings returns to the surface of the well through an annulus formed between the outer diameter of the drillstring and the inside diameter of the drilled bore. For this reason, it is not uncommon for a drill bit to be disposed upon the end of a smaller diameter drillstring. Furthermore, to reduce the amount of drillstring weight on the drill bit, drill pipes of the drillstring are often constructed from relatively thin-walled tubes and do not exhibit a high amount resistance to torsional stresses and strain, or torsional impedance.

[0003] Because some weight on the drill bit is desirable to properly load the bit, weight collars are typically located behind the bit. These weight collars, typically constructed as thick-walled tubular members, have an increased moment of inertia compared to the drill pipe sections thereabove. Because of the high weight at the distal end relative to its remainder, the drillstring has the capability to act as a torsional (rotational) pendulum in its movement. Pulses in rotational displacement of the drill bit and weight collars downhole create oscillatory conditions in the lighter remainder portion of the drillstring along its length. As the length of the drillstring increases, the torsional vibrations of the drillstring become more pronounced and unpredictable. These vibrations adversely impact drilling equipment located at the proximal end of the drillstring and shorten the life thereof, necessitating costly and time consuming repair and reconditioning operations.

[0004] One unfavorable oscillatory drillstring condition is commonly known as stick-slip, whereby the drill bit does not rotate continuously and smoothly at the bottom of the hole. A stick-slip condition occurs when the drill bit gets caught on the formation, hangs momentarily while torsional energy and strain builds up in the drillstring, and then rotates again when the torsional strain is high enough to overcome the snag in the formation. When the drill bit is released from the snag in the formation, the bit accelerates to a speed faster than the rotation of the surface by the drive system so the drill bit can "catch up" to the radial position of the drillstring. This phenomenon causes a "jerky" and oscillatory rotation of the drill bit and drillstring even though the drillstring is rotated at a substantially constant pace hundreds or thousands of feet above at the surface. These cyclical speed variations and torsional loading and unloading of the drillstring transmit torsional vibrations, stresses, and strains to drive equipment at the surface and causes damage and premature wear. Bit-bounce is a similar drillstring and drill bit phenomenon that also damages equipment and reduces the rate of penetration. Bit-bounce is similar to stick-slip, but bit-bounce implies an axial (up and down) component to the stress and vibrations experienced.


[0005] Inventions have been devised to reduce the amount of stick-slip and bit-bounce in the drillstring to prolong the life of drillstring components but they do not protect surface driving equipment. One such invention, U.S. Pat. No. 6,166, 654 issued to Leon Van Den Steen on Dec. 26, 2000 and entitled "Drilling Assembly with Reduced Stick-Slip Tendency" is hereby incorporated by reference herein. Another invention, U.S. Pat. No. 6,308,940 issued to Edwin Anderson on Oct. 30, 2001 and entitled "Rotary and Longitudinal Shock Absorber for Drilling" is also hereby incorporated by reference herein. Most inventions of the prior art attempt to reduce torsional vibrations in the drillstring rather than protect equipment from the vibrations. Furthermore, since these solutions tend to reduce the torsional vibrations rather than eliminate them, protection of equipment is still necessary. An invention to reduce the effects of these inevitable vibrations at the surface is still needed.

[0006] With the advent of top drive drilling systems, those that rotate and drive the drillstring from the lifting bales of the rig itself, torsional vibrations can become costly. Top drive assemblies are typically large motors that raise and lower with the lifting bales of the rig and angularly drive the drillstring. Typically, the top drive slides up and down and is guided by a pair of structural rails so torque can be applied to the drillstring without the top drive or the lifting bales twisting. As such, the drillstring is in direct, hard, contact with the top drive assembly so any torsional vibrations or loads will be transmitted directly thereto. Formerly, rotary table drive systems allowed the drillstring to be driven by a Kelly drive unit that would slide up and down through a profile in the center of the rotary table. The table profile would have a geometric polygonal (usually square or hexagonal) profile to correspond with a matching profile of the Kelly. The rotary table profile usually included enough clearance so the Kelly could be easily slidably engaged therethrough. Older, rotary table systems, while susceptible to torsional vibrations, were not as easily and costly damaged as the newer top drive systems are today.

[0007] Furthermore, with the advent of casing drilling, torsional vibrations become more of an issue than they were under conventional drillstring drilling. Casing drilling involves the use of a casing string, i.e. a relatively large diameter steel tubing intended to remain in place in the wellbore following installation, to transport and drive the BHA to the bottom of the wellbore. The benefit of casing drilling is that the wellbore is simultaneously drilled and
cased, thus saving time of “tripping out” the drillstring and subsequently running a separate casing operation. Using a casing drilling scheme, the wellbore is drilled using the larger diameter casing string as a drillstring and the bottom hole assembly is retrieved therethrough when complete, leaving the casing behind in the wellbore to be cemented in place (if desired). Society of Petroleum Engineering technical papers 52789 and 67731 respectively authored by R. Tessari, et al. and S. Shepard, et al. and respectively entitled “Casing Drilling: A Revolutionary Approach to Reducing Well Costs” and “Casing Drilling: An Emerging Technology,” hereby incorporated herein by reference, disclose developments and benefits of casing drilling systems.

[0008] However beneficial and cost effective, casing drilling poses new challenges with respect to torsional vibrations resulting from stick-slip conditions. Particularly it has been observed that high-frequency torsional vibrations in casing drilling are more severe than when using ordinary drill pipe as a drillstring. It is suggested that this phenomenon results from a higher torsional stiffness of the casing relative to the drill pipe. Furthermore, the torsional vibrations are increased when pipe is run within other pipe (i.e. drillstring run within emplaced casing string), possibly from resonance between the two strings.

[0009] It has been suggested that solutions to the high-frequency vibrations experienced with casing drilling are to slow the rotary drilling speed, increase the lubricity of the drilling mud used, and modify the ratio of inner diameter to outer diameter. Slowing the rotary drilling speed is not favored because it has a negative impact on the rate of penetration (ROP) of the drill assembly, making drilling take longer and more costly. Second, changing the drilling fluid composition is not always financially or physically feasible for a particular well. Finally, the ratio of the inside diameter to the outside diameter can only be finitely changed. If a well is to be created with a certain size casing, the operator is not given much freedom to deviate from the well specifications. Running larger casing entails drilling a larger bore, thereby increasing the cost of the well dramatically.

[0010] A system to protect more modern and expensive top drive drilling assemblies from torsional vibrations is needed in the art. The embodiments herein address the shortcomings of the current state of the art in this regard.

SUMMARY OF THE INVENTION

[0011] The discrepancies of the prior art are addressed by a method to reduce torsional vibrations in a drilling apparatus. The method preferably includes connecting a bottom hole assembly to a distal end of a drillstring and driving a proximal end of the drillstring with a top drive unit. The method preferably includes connecting a torsional baffle between a proximal end of the drillstring and a top drive unit. The method preferably includes rotating the proximal end of the drillstring and the torsional baffle with the top drive unit. The method preferably includes impeding torsional vibrations from the drillstring and the bottom hole assembly with the torsional baffle.

[0012] The discrepancies of the prior art are also addressed by an apparatus to impede torsional vibrations in a drillstring. The apparatus preferably includes a bottom hole assembly located in a wellbore upon a distal end of the drillstring. The apparatus preferably includes a drive unit configured to rotate and manipulate the drillstring. The apparatus preferably includes a torsional baffle located upon a proximal end of the drillstring, wherein the torsional baffle has torsional impedance sufficient enough to reduce torsional vibrations of the drillstring impacting upon the drive unit.

[0013] The discrepancies of the prior art are also addressed by a top drive assembly to drive a drillstring within a wellbore. The top drive assembly preferably includes a bottom hole assembly located in the wellbore upon a distal end of the drillstring, wherein the bottom hole assembly includes a drill bit. The top drive assembly preferably includes a torsional baffle located between the top drive assembly and the proximal end of the drillstring. Preferably, the torsional baffle has a torsional impedance to reduce torsional vibrations experienced by the top drive assembly.

BRIEF DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0014] FIG. 1 is a schematic view drawing of a top drive system using a torsional baffle in accordance with a first preferred embodiment of the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0015] Referring to FIG. 1, a drilling assembly 100 is shown schematically. Drilling assembly 100 preferably includes a top drive unit 102, a torsional baffle 104, a length of drillstring 106, and a bottom hole assembly (BHA) 108. As described above, BHA 108 is much more dense and heavier relative to drillstring 106. As such, when the drill bit of BHA 108 encounters a stick-slip condition downhole, the oscillations of bit sticking and slipping is likely to induce a torsional oscillation into drillstring 106. These torsional oscillations are transmitted up drillstring 106 and to top drive unit 102. Torsional baffle 104 acts to dampen these angular oscillations, thereby reducing the force and magnitude of any stresses experienced therefrom by top drive unit 102. Preferably, a linking sub 110 connects baffle 104 to top drive unit 102. Linking sub 110 is constructed so as to minimize any torsional vibrations or oscillations that may be created when top drive 102 and baffle 104 interact with each other. By adding baffle 104 and linking sub 110 under top drive unit 102, the top drive is “beefed up” and protected from damaging downhole torsional oscillations.

[0016] Baffle 104 is preferably constructed as a terminator of high torsional impedance and designed to increase drilling stability and isolate top drive 102 from torsional oscillations in drillstring 106. Baffle 104 is preferably similar to a flywheel or gyroscope, albeit a low RPM flywheel or gyroscope. Therefore, baffle 104 is preferably constructed to have large torsional impedance so that high frequency torsional vibrations are not transmitted therethrough. To maximize the torsional impedance, baffle 104 can be constructed as a solid, steel disc or cylinder. While a solid steel structure is disclosed, it should be understood by anyone skilled in the art that any material or configuration can be used to maximize torsional impedance. Because top drive unit 102 already carries a large moment of inertia, torsional impedance is more important to the success of baffle 104 in reducing torsional vibrations than the moment of inertia.
Furthermore, as torsional impedance increases more rapidly with mass in the transverse (radial) direction rather than the longitudinal direction, baffle 104 cylinders with a relatively large diameter to length ratio are preferable. Tests depicting this radial scaling of impedance have shown torsional baffles constructed 24 inches in diameter and three feet long to have similar impedance values to baffles constructed 31 inches in diameter and only one foot in length. For this reason, an operator wishing to conserve "height" below top drive unit 102 may opt for disc-shaped geometries for baffle 108 over cylinder-shaped geometries. Vertical space is at a premium on drilling sites and a savings of even a few inches would be highly beneficial to a rig operator. While it would be desirable to determine a size and configuration of baffle 104 that would stabilize drillstrings of various sizes and configurations, it does not seem possible. Too many variables exist with regard to the drilling mud, drillstring, formation, and other equipment used to make that goal reachable. Therefore, it is an advantage of the mechanical baffles 104 that they are cheap, easily handled, and a range of them can be used experimentally to attempt a particular system.

Using a baffle 104 in accordance with the present invention, tests show that stick-slip and rig vibrations are markedly reduced. Baffle 104 is therefore preferably used as a drillstring terminator of high torsional impedance to increase drillstring stability or to isolate top drive unit 102 from torsional oscillations in drillstring 106. Furthermore, devices having large angular momentum (including, but not limited to, gyroscopes and flywheels) can be added to drillstring 106 or top drive unit 102 itself to make top drive unit 102 stiffer.

Numerous embodiments and alternatives thereof have been disclosed. While the above disclosure includes the best mode believed to carry out the invention as contemplated by the named inventors, not all possible alternatives have been disclosed. For that reason, the scope and limitations of the present invention is not to be restricted to the above disclosure, but is instead to be defined and construed by the appended claims.

1. A method to reduce torsional vibrations in a drilling apparatus, the method comprising:
   connecting a bottom hole assembly to a distal end of a drillstring;
   driving a proximal end of the drillstring with a top drive unit;
   connecting a torsional baffle between the proximal end of the drillstring and the top drive unit;
   rotating the proximal end of the drillstring and the torsional baffle with the top drive unit;
   impeding torsional vibrations from the drillstring and the bottom hole assembly with the torsional baffle.

2. The method of claim 1 wherein the drillstring is a casing string.

3. The method of claim 1 wherein the torsional baffle is disc-shaped.

4. The method of claim 3 wherein the torsional baffle has a diameter greater than 24 inches.

5. The method of claim 3 wherein the torsional baffle has a diameter to thickness ratio greater than 2.5.

6. The method of claim 1 wherein the torsional baffle is cylinder-shaped.

7. The method of claim 6 wherein the torsional baffle has a length of less than 36 inches.

8. The method of claim 1 wherein the torsional baffle is constructed as a solid metal disc.

9. The method of claim 1 wherein a linking sub connects the torsional baffle to the top drive unit.

10. The method of claim 1 wherein the torsional baffle is configured to impede the transmission of high-frequency vibrations from the drillstring to the top drive unit.

11. The method of claim 1 further comprising selecting a configuration for the torsional baffle based upon wellbore parameters.

12. The method of claim 11 wherein the wellbore conditions are selected from the group including drillstring inner diameter, drillstring outer diameter, drillstring length, drilling mud lubricity, drilling rotational speed, and wellbore formation.

13. An apparatus to impede torsional vibrations in a drillstring, the apparatus comprising:
   a bottom hole assembly located in a wellbore upon a distal end of the drillstring;
   a drive unit configured to rotate and manipulate the drillstring;
   a torsional baffle located upon a proximal end of the drillstring;
   the torsional baffle having a torsional impedance sufficient enough to reduce torsional vibrations of the drillstring impacting upon the drive unit.

14. The apparatus of claim 13 wherein the drive unit is a rotary table.

15. The apparatus of claim 13 wherein the drive unit is a top drive.

16. The apparatus of claim 13 wherein the torsional baffle is disc-shaped.

17. The apparatus of claim 16 wherein the torsional baffle has a radius greater than 24 inches.

18. The apparatus of claim 16 wherein the torsional baffle has a radius to thickness ratio greater than 2.5.

19. The apparatus of claim 13 wherein the torsional baffle is cylinder-shaped.

20. The apparatus of claim 13 wherein the torsional vibrations are the result of stick-slip of the bottom hole assembly.

21. The apparatus of claim 13 wherein the torsional vibrations are the result of bit-bounce of the bottom hole assembly.

22. The apparatus of claim 13 wherein the torsional baffle is constructed from a homogeneous dense metallic material.

23. The apparatus of claim 22 wherein the dense metallic material is selected from the group consisting of iron, stainless steel, steel, and tungsten.

24. The apparatus of claim 13 wherein the drillstring is a casing string.
25. A top drive assembly to drive a drillstring within a wellbore, the top drive assembly comprising:

a bottom hole assembly located in the wellbore upon a distal end of the drillstring, the bottom hole assembly including a drill bit;

a torsional baffle located between the top drive assembly and the proximal end of the drillstring;

the torsional baffle having a torsional impedance to reduce torsional vibrations experienced by the top drive assembly.

26. The top drive assembly of claim 25 wherein the torsional baffle includes a homogeneous metallic disc.

27. The top drive assembly of claim 26 wherein the homogeneous metallic disc has a radius greater than 24 inches.

28. The top drive assembly of claim 26 wherein the homogeneous metallic disc has a radius to thickness ratio greater than 2.5.

29. The top drive assembly of claim 25 wherein the torsional baffle includes a homogeneous metallic cylinder.

30. The top drive assembly of claim 25 wherein the torsional vibrations are generated by the drill bit experiencing a stick-slip condition in the wellbore.

31. The top drive assembly of claim 25 wherein the drillstring is a casing string.