

ROTARY CONE DRILL BIT HAVING
A BIT BODY WITH INTEGRAL STABILIZERS

TECHNICAL FIELD OF THE INVENTION

This invention relates in general to the field of rotary cone drill bits used in drilling a borehole in the earth and in particular to a drill bit having a bit body
5 with integral stabilizers formed on the exterior thereof.

BACKGROUND OF THE INVENTION

Various types of drill bits and rock bits may be used to form a borehole in the earth. Examples of such drill bits include roller cone drill bits or rotary cone drill bits used in drilling oil and gas wells. A typical rotary cone drill bit includes a bit body with an upper end adapted for connection to a drill string. A plurality of support arms, typically two or three, depend from a lower portion of the bit body. Each support arm generally has a spindle or journal attached thereto and protruding radially inward and downward with respect to a projected rotational axis of the bit body.

Conventional roller cone bits are often constructed in three segments. The segments are generally positioned together longitudinally with a welding groove between each segment. The segments may then be welded with each other using conventional techniques to form the bit body. Each segment also includes an associated support arm as an integral component extending from a lower portion of the bit body. An enlarged cavity or fluid passageway is generally formed in the bit body to receive drilling fluids from an attached drill string. U.S. Patent 4,054,772 entitled, *Positioning System for Rock Bit Welding* shows a method and apparatus for constructing a typical rotary cone drill bit from three individual segments.

Rotary cone drill bits are sometimes manufactured with only two support arms and cutter cone assemblies. See for example, U.S. Patent 4,067,406 entitled, *Soft Formation Drill Bit* and U.S. Patent 1,143,273 entitled, *Rotary Drill*. Rotary cone drill bits may also be manufactured from a unitary bit body with respective

support arm and cutter cone assemblies attached thereto. See for example, U.S. Patent 5,641,029 entitled, *Rotary Drill Bit Modular Arm*.

5 A cutter cone assembly is generally mounted on each spindle and rotatably supported on bearings disposed between the exterior of each spindle and the interior of a cavity formed in the respective cutter cone assembly. One or more nozzles may be formed in the bit body adjacent to the support arms. The nozzles are typically positioned to direct drilling fluid passing downwardly from an associated drill string through the cavity or fluid passageway in the bit body toward the bottom of the borehole.

15 Drilling fluid is generally provided by the drill string to perform several functions including washing away cuttings and other material from the bottom of the borehole, cleaning the cutter cone assemblies, and carrying the cuttings and other material radially outward and then upward within an annulus defined in part by the exterior of the drill string and the sidewall of the borehole. U.S. Patent 4,056,153 entitled, *Rotary Rock Bit with Multiple Row Coverage for Very Hard Formations* and U.S. Patent 4,280,571 entitled, *Rock Bit* show examples of conventional roller cone bits with cutter cone assemblies mounted on a spindle projecting from a support arm.

25 Rotation and vibration of a drill string, particularly in deep and/or highly deviated boreholes, will frequently require stabilization of the drill string and attached drill bit within the borehole. Various types of stabilizers and/or centralizers have previously been used as part of a downhole drilling assembly.

For some applications, a stabilizer may be a separate component attached to the drill string above the drill bit. Alternatively, stabilizer pads or lugs may be welded to the exterior of a drill bit after original
5 manufacture of the drill bit. Typically, such stabilizer pads have been attached to the support arms. For example, Security DBS a division of Dresser Industries, has developed stabilizer pads or lugs to provide additional bit stabilization and shirrtail protection during severe
10 downhole drilling applications. Such stabilizer pads may be particularly effective during drilling of horizontal and directional wellbores which result in side loading of the associated drill bit and premature drill bit failure due to increased abrasion, erosion, and/or wear of the
15 associated shirrtail portions. Such stabilizer pads or lugs are generally manufactured as separate components and attached by welding to the exterior of support arms of a selected drill bit. Flush surface tungsten carbide inserts may be included as part of such stabilizer pads
20 or lugs to further enhance abrasion, erosion and/or wear resistance.

U.S. Patent 5,755,297 entitled *Rotary Cone Drill Bit With Integral Stabilizers* describes a rotary cone drill bit in which a stabilizer pad is formed as an integral
25 part of the exterior surface of each support arm attached to and extending from the associated bit body. The stabilizer pads project radially outward from respective support arms a distance approximately equal to a desired radius for the borehole being formed by the drill bit.
30 Any heat generated by contact between such stabilizer pads and the inside diameter of a borehole may on some occasion be transferred to various components such as

elastomeric seals and/or a lubricant reservoir carried within the associated support arm/cutter cone assembly.

5 Hardfacing of metal surfaces and substrates is a well-known technique to minimize or prevent abrasion, erosion and wear of the metal surfaces or substrates. Hardfacing can be generally defined as applying a layer of hard, abrasion resistant material to a less resistant surface or substrate by plating, welding, spraying or other well known metal deposition techniques. Hardfacing
10 is frequently used to extend the service life of drill bits and other downhole tools used in the oil and gas industry. Tungsten carbide and its various alloys are some of the more widely used hardfacing materials to protect drill bits and other downhole tools associated
15 with drilling and producing oil and gas wells.

SUMMARY OF THE INVENTION

In accordance with teachings of the present invention, disadvantages and problems associated with previous rotary cone drill bits have been substantially reduced or eliminated. One embodiment of the present invention includes a rotary cone drill bit having a bit body with stabilizer pads or lugs formed as integral components thereof and extending generally radially therefrom. Each stabilizer pad of a lug is preferably disposed on the exterior of the bit body between respective support arms. For some applications, the stabilizer pads and support arms will be disposed in a generally symmetrical pattern on the exterior of the associated bit body. For other applications the stabilizer pads and/or support arms may be disposed in a generally non-symmetrical configuration on the exterior of the associated bit body. Non-symmetrical configurations may be particularly beneficial for some directional drilling requirements. Also, non-symmetrical configurations may enhance the flow of drilling fluids with entrained cuttings and other debris from the bottom of a borehole into an associated annulus for return to the well surface.

For one application, a drill bit is provided with two support arms and respective cutter cone assemblies rotatably mounted thereon. The respective arms and cutter cone assemblies are preferably attached to and spaced approximately one hundred and eighty degrees (180°) from each other on the exterior of an associated bit body. At least two stabilizer pads or lugs are preferably formed as integral components of the bit body. The stabilizer pads or lugs preferably extend radially

from opposite sides of the bit body intermediate the support arms. The stabilizer pads or lugs may have various configurations to optimize downhole drilling performance and return of drilling fluids with entrained cuttings to the well surface.

For another application, a drill bit is provided with a bit body having three support arms and respective cutter cone assemblies rotatably mounted thereon. The respective support arms and cutter cone assemblies are preferably spaced approximately one hundred and twenty degrees (120°) from each other on the exterior of an associated bit body. At least three stabilizer pads or lugs are preferably formed as integral components of the bit body. The stabilizer pads or lugs are preferably disposed approximately one hundred and twenty degrees (120°) from each other on the exterior of the bit body and extending radially therefrom. Each stabilizer pad or lug is preferably disposed intermediate two of the support arms.

Technical advantages of the present invention include providing a drill bit having a bit body with a plurality of stabilizer lugs or pads formed as an integral component thereof. The integral stabilizer pads or lugs will often eliminate any requirement to include a stabilizer as separate component in an associate drill string above the drill bit and associated extra threaded connections. Stabilizer pads or lugs formed as an integral component of a bit body in accordance with the teachings of the present invention are substantially less subject to cracking and/or corrosion as composed with lugs or pads added to previously manufactured drill bits using appropriate welding processes. Sometimes

stabilizer pads or lugs may be attached to the exterior of a bit body in field locations having less than desired welding capabilities and/or quality control procedures. Teachings of the present invention allow substantially improved quality control and substantially reduced variation in dimensional tolerances.

Forming stabilizer pads or lugs as integral components of a bit body will often allow any heat generated by contact between the stabilizer pads or lugs and the inside diameter or sidewall of a wellbore to be more readily dissipated through the bit body and drilling fluids flowing there through.

The present invention allows fabricating a plurality of stabilizer pads or lugs as integral components of a bit body prior to attaching support arms and cutter cone assemblies to the bit body. As a result of the present invention, compacts and/or inserts may be installed within the integral stabilizer pads or lugs and/or hardfacing material applied to exterior portions of the stabilizer pads or lugs to minimize abrasion, erosion and/or wear prior to assembly of the drill bit. As a result, the components of the lubricant reservoir and elastomeric sealing systems which are typically installed within a support arm/cutter cone assembly are not exposed to high temperatures associated with installing inserts and compacts and/or applying hardfacing. Alternatively, stabilizer pads or lugs may be manufactured with one or more pockets to accommodate installing inserts and/or compacts after the associated drill bit has been assembled. For some downhole environments it may not be necessary to include inserts, compacts or hardfacing as part of the stabilizer pads.

One aspect of the present invention includes fabricating a plurality of stabilizer pads or lugs as an integral components of a bit body intermediate locations for attachment of support arms and cutter cone assemblies. The stabilizer pads or lugs will thus provide additional contact points between the exterior of the associated drill bit and the inside diameter or sidewall of a borehole which are both radially and longitudinally off set from the contact point of each support arm/cutter cone assembly and the inside diameter or sidewall of the borehole. Forming stabilizer pads or lugs as integral components of a bit body will often substantially enhances downhole stability of the associated drill bit.

Further technical benefits of the present invention include optimizing the location and configuration of each integral stabilizer pad or lug on the exterior of a bit body to optimize fluid flow and downhole stability of the resulting drill bit. For example, various configurations such as swirled or straight may be selected to optimize the performance of the associated drill bit. The stabilizer pads are preferably offset from each other and respective support arms attached to the bit body to optimize the flow of fluid, cuttings, and other debris from the bottom of a borehole to an annulus formed between the sidewall of the borehole and the exterior of the associated drill string. Welding techniques associated with attaching stabilizer pads to the exterior of previously manufactured drill bits frequently limit suitable locations for attachment to the exterior of the drill bit. Thus, fabrication of stabilizer pads or lugs as integral components of the bit body and application of

hardfacing prior to assembly of the resulting drill bit may be optimized without concern for potential heat damage to other components such as elastomeric seals and/or lubricant reservoirs.

5 Still further technical advantages of the present invention include providing a plurality of integral stabilizer pads on the exterior of the bit body to divide turbulent fluid flow around the associated rotating cutter cone assemblies from fluid flow in the annulus
10 above the drill bit such that cuttings and other debris entering the annulus generally will not be drawn back down toward the cutter cone assemblies. Fluid flow below the integral stabilizer pads is generally turbulent and multidirectional due to fluid exiting associated nozzles
15 and the churning effect of the cutter cone assemblies. The stabilizer pads cooperate with other components of the bit body to separate fluid flow at the drill bit into two substantially independent regions. Fluid flow above the stabilizer pads is generally less turbulent and more
20 unidirectionally upward.

 Another aspect of the present invention includes providing a drill bit having a bit body with a plurality of stabilizer pads or lugs formed as an integral components thereof with a plurality of insert and/or
25 compacts disposed in exterior portions of each stabilizer pad or lug. For some applications, the inserts and/or compacts may be substantially the same as conventional inserts and compacts associated with reducing abrasion erosion and/or wear of conventional drill bits. For
30 other applications, one or more poly diamond crystalline (PDC) inserts may be installed at selected locations within each stabilizer pad or lug. The PDC inserts may

be sized to assist the cutting structure of the associated drill bit in maintaining the desired gauge diameter of a borehole. The number location and types of inserts and/or compacts installed within each stabilizer pad may be selected in accordance with teachings of the present invention to optimize the drilling performance and downhole service life of the associated drill bit.

The combined surface area of the integral stabilizer pads or lugs is preferably relatively large as compared to the total surface area of contact between the associated cutting structure and the inside diameter of the borehole. Thus, as the gauge surface or gauge diameter of the associated cutting structure starts to wear and/or erode, the stabilizer pads will contact adjacent portions of the borehole. The increased surface area of the stabilizer pads or lugs will result in increased torque loading of the drill bit and associated drill string. This increased torque loading may be monitored at the well surface to indicate the extent of any wear and/or erosion of the gauge surfaces of the drill bits. Thus, forming stabilizer pads or lugs as integral components of a bit body in accordance with teachings of the present invention will provide an early warning of drill bit wear prior to catastrophic failure of the associated cutting structure.

Forming stabilizer pads or lugs as integral component of a bit body in accordance with teachings of the present invention will often allow installing fluid nozzles at a greater distance from the longitudinal axis of an associated bit body and/or installing an increased number of fluid nozzles within the lower portion of the bit body. As a result, forming a bit body with integral

stabilizer lugs or pads allows more opportunity for optimizing the number, location and size of nozzles used to direct drilling fluid from the associated drill string toward the bottom of a borehole.

5 By forming stabilizer pads or lugs as integral components of a bit body, corresponding dimensions (thickness, length, width, and exterior radius) of the stabilizer pads may be optimized to enhance downhole drilling performance of the resulting drill bit.

10 Vibration and lateral movement of the associated drill bit at the bottom of the borehole during drilling operations may be substantially reduced or eliminated.

Scoring or plowing of the sidewall is a significant concern in directional and/or extended reach horizontal drilling applications. For some downhole applications, 15 the length of the bit body may be increased to provide larger stabilizer pads or lugs for even greater downhole drilling stability.

Drill bits incorporating teachings of the present invention may demonstrate longer downhole drilling life, 20 higher rate of penetration (ROP) and lower total drilling costs. Technical advantages of such drill bits may include improved downhole cleaning, higher fluid flow rate capabilities, reduced bit balling problems, more consistent uniform downhole drilling performance and 25 reduced directional drilling problems by eliminating or substantially reducing "plowing" or scoring of the sidewall of a borehole while tripping the associated drill bit.

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BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding of the present invention, and advantages thereof, reference is now made to the following description taken in conjunction with the accompanying drawings in which like reference numbers indicate like features and wherein:

FIGURE 1 is a schematic drawing in elevation with portions broken away showing a rotary cone drill bit incorporating teachings of the present invention having a bit body with integral stabilizer pads and three support arm/cutter cone assemblies;

FIGURE 2 is a schematic drawing showing an end view of a bit body, satisfactory for use with the drill bit of FIGURE 1, having stabilizer pads formed as integral components thereof in accordance with teachings of the present invention;

FIGURE 3 is a schematic drawing in section of the bit body of FIGURE 2;

FIGURE 4 is a schematic drawing in elevation with portions broken away showing a rotary cone drill bit incorporating teachings of the present invention having a bit body with integral stabilizer pads and two support arm/cutter cone assemblies; and

FIGURE 5 is a schematic drawing showing an end view of the drill bit of FIGURE 4.

DETAILED DESCRIPTION OF THE INVENTION

The present invention and its advantages are best understood by referring to FIGURES 1 through 5 of the drawings, like numerals being used for like and
5 corresponding parts of the drawings.

FIGURE 1 is a schematic drawing showing an isometric view of a rotary cone drill bit indicated generally at 20, incorporating various teachings of the present invention. Drill bit 20 may sometimes be referred to as
10 a roller cone drill bit or a rotary rock bit.

Drill bit 20 may be attached to drill string 22 (shown in dotted lines) and disposed within a borehole (not expressly shown). An annulus (not expressly shown) is formed between the exterior of drill string 22 and the
15 inside diameter or sidewall of the borehole. In addition to rotating drill bit 20, drill string 22 is used as a conduit to communicate drilling fluids and other fluids from the well surface (not expressly shown) to drill bit
20 at the bottom of the borehole. Such drilling fluids may be directed to flow from drill string 22 through bit body 30 to various nozzles (not expressly shown) disposed within respective openings 32 provided in drill bit 20. Cuttings formed by drill bit 20 and other debris at the bottom of the borehole will mix with drilling fluid
25 exiting from one or more nozzles and return to the well surface via the annulus.

For the embodiment shown in FIGURE 1, drill bit 20 preferably includes one piece or unitary bit body 30. Bit body 30 includes upper portion 34 having threaded
30 connection or pin 36 adapted to secure drill bit 20 with the lower end of drill string 22. Three support arms 70 are preferably attached to and extend longitudinally from

bit body 30 opposite from threaded connection 36. Only two support arms 70 and attached cutter cone assemblies 90 are shown in FIGURE 1.

Each support arm 70 preferably includes a spindle (not expressly shown) connected to and extending from inside surface 72 of the respective support arm 70. Cutter cone assemblies 90 are rotatably mounted on respective spindles which extend generally downward and inward from each support arm 70. Each cutter cone assembly 90 includes a plurality of inserts 92 which scrape and gouge against the sides and bottom of the borehole in response to weight and rotation applied to drill bit 20 by drill string 22. A plurality of surface compacts 94 are disposed in gauge face surface 98 of each cutter cone assembly 90. Inserts 92 and surface compacts 94 may be formed from various types of hard materials associated with the manufacture of drill bits.

An important feature of the present invention includes the ability to fabricate stabilizer pads or lugs 50 as integral components of bit body 30 prior to attaching support arms 70 and cutter cone assemblies 90 thereto. However, a bit body having stabilizer pads formed as integral components thereof in accordance with teachings of the present invention may be used with a wide variety of cutting structures. Other types of cutter cone assemblies and cutting structures may be satisfactorily used with the present invention including, but not limited to, cutter cone assemblies having milled teeth instead of inserts 92. The present invention is not limited to use with only support arms 70 and cutter cones 90.

As shown in FIGURES 2 and 3, enlarged cavity 31 may be formed within upper portion 34 of bit body 30. An opening (not expressly shown) is provided in upper portion 34 for communicating fluids between drill string 22 and cavity 31. Cavity 31 preferably has a generally uniform inside diameter extending from upper portion 34 to a position intermediate middle portion 42 of bit body 30. For some applications, cavity 31 may be formed concentric with longitudinal axis 46 of bit body 30. Cavity 31 provides a relatively large fluid chamber having little if any resistance to fluid flow from drill string 22 into drill bit 20.

One or more fluid passageways 42 may be formed in bit body 30 extending between cavity 31 and convex surface 40 on lower portion 38 of bit body 30. Openings 32 may be provided in each fluid passageway 42 adjacent to convex surface 40. A plurality of recesses are preferably provided within each opening 32 to allow installing various types of nozzles or nozzle inserts within each fluid passageway 42. Additional components (not expressly shown) such as a snap ring and/or O-ring seal may be provided to position each nozzle opening 32 within its respective recesses. Cavity 31 and passageways 42 cooperate with each other to provide improved fluid flow and enhanced cleaning efficiency at cutter cone assemblies 90.

Various techniques are commercially available for satisfactorily installing each nozzles and/or nozzle inserts within openings 32. For some applications, such nozzles may be formed from tungsten carbide or other suitable materials to resist erosion from fluids flowing therethrough. Also, one or more access ports (not shown)

may be provided in bit body 30 adjacent to nozzle openings 32 to allow lock screws or pins and/or plug welds (not shown) to secure nozzle openings 32 within respective recesses.

5 Nozzle openings 32 may be disposed in each fluid flow passageway 42 to regulate fluid flow from cavity 31 through the respective fluid passageway 42 and the associated nozzle openings 32 to the exterior of bit body 30. The length and diameter of each fluid passageway 42
10 may be selected for some applications to provide laminar flow between cavity 31 and the respective nozzle openings 32. The present invention allows forming fluid passageway 42 with a diameter larger than previously possible with conventional rotary cone drill bits.

15 An important feature of the present invention includes the ability to vary the position of fluid passageways 42 and associated nozzle openings 32 within bit body 30 without affecting the location of pockets 48 and associated support arms 70. For some applications,
20 nozzle openings 32 will preferably be positioned to direct drilling fluid flow between adjacent cutter cone assemblies 90. As a result of improved cutting removal and better cleaning at the bottom of a borehole, the efficiency and rate of penetration (ROP) of drill bit 20
25 will be substantially improved.

 Stabilizer pads 50 are formed on the exterior of bit body 30 as integral components thereof to stabilize drill bit 20 within the associated borehole and to provide early indication of erosion, abrasion and/or wear.
30 Stabilizer pads 50 preferably extend radially from bit body 30 a distance which is slightly less than to the desired radius or gauge diameter of the associated

borehole. For the embodiment of the present invention as shown in FIGURES 1, 2 and 3 bit body 30 includes three stabilizer pads 50.

5 For some applications, stabilizer pads 50 may be formed as integral components of bit body 30 by machining an appropriately sized piece of raw material. Stabilizer pads 50 may also be formed as an integral part of bit body 30 during forging or casting thereof. After bit body 30 has been formed by forging or casting, stabilizer
10 pads 50 may be further machined to provide desired dimensions and configurations thereof.

U.S. Patent 5,439,067 entitled *Rock Bit With Enhanced Fluid Return Area* and U.S. Patent 5,439,068 entitled *Modular Rotary Drill Bit* provides additional
15 information concerning the manufacture and assembly of unitary bit bodies and associated support arm/cutter cone assemblies satisfactory for use with the present invention.

Bit body 30 includes lower portion 38 having a
20 generally convex exterior surface 40 formed thereon. Lower portion 38 may sometimes be referred to as a dome. The dimensions of convex surface 40 and the location of cutter cone assemblies 90 relative to lower portion 38 may be varied by adjusting the length of support arms 70
25 and radial spacing between each support arm 70 on the exterior of bit body 30. However, a bit body having stabilizer pads formed as integral components thereof in accordance with teachings of the present invention may have a wide variety of configurations other than convex
30 surface 40.

Debris carrying drilling fluid will generally flow radially outward between convex surface 40 and the bottom

of the associated borehole and then flow generally upward toward the well surface through the associated annulus. For the embodiment of the present invention as shown in FIGURES 1, 2 and 3, bit body 30 includes three nozzle openings 32 and respective fluid flow passageways 42.

Forming nozzle openings 32 and their associated fluid flow passages 42 within unitary bit body 30 eliminates the requirement to form nozzle bosses associated with conventional drill bits on the exterior of bit body 30. Forming stabilizer pads 50 as integral components of bit body 30 allows selecting the desired number and/or location of nozzle openings 32 to optimize the flow of drilling fluid from drill string 22 through bit body 30 toward the bottom of the associated borehole in accordance with teachings of the present invention.

As shown in FIGURE 2, the location of each nozzle opening 32 corresponds generally with a respective stabilizer pad 50. As a result, stabilizer pads 50 allow locating each nozzle opening 32 at a greater distance radially from longitudinal axis 46 as compared to a similar size and type of bit body which did not include stabilizer pads or lugs as an integral component thereof.

Bit body 30 includes middle portion 44 disposed between upper portion 34 and lower portion 38. Longitudinal axis or central axis 46 extends through bit body 30 and corresponds generally with the projected axis of rotation for drill bit 20. Middle portion 44 preferably has a generally cylindrical configuration with pockets 48 formed in the exterior thereof and spaced radially from each other. The number of pockets 48 is selected to correspond with the number of support arms 70 which will be attached thereto. Spacing between pockets

48 in the exterior of middle portion 44 is selected to correspond with the desired spacing between support arms 70 and their associated cutter cone assemblies 90. The location of pockets 48 may also be varied to provide any desired offset for cutter cone assemblies 90 with respect to longitudinal axis 46 and the projected axis of rotation for drill bit 20.

FIGURE 2 shows lower portion 38 of bit body 30 having three pockets 48 and three nozzle openings 32. Fluid passageways 42 are shown in dotted lines extending from enlarged cavity 31 to respective nozzle openings 32. Fluid passageways 42 are spaced radially with respect to each other and extend from longitudinal axis 46. For the example shown in FIGURE 2, fluid passageways 42 and associated nozzle openings 32 are spaced radially approximately one hundred twenty degrees (120°) from each other. In a similar manner, each pocket 48 is spaced radially approximately one hundred twenty degrees (120°) from an adjacent pocket 48.

Each support arm 70 has a longitudinal axis extending therethrough. Support arms 70 are preferably mounted in their respective pockets 48 with their respective longitudinal axis aligned parallel with each other and with longitudinal axis 46 of the associated bit body 30. Portions of each support arm 70 are preferably welded within respective pocket 48 by a series of welds (not expressly shown) formed between the exterior or perimeter of each pocket 48 and adjacent portions of respective support arm 70. The perimeter of each pocket 48 adjacent to the exterior of bit body 30 may be modified to provide welding surfaces and/or welding

grooves to assist with attaching support arms 70 within respective pockets 46.

Each pocket 48 is preferably disposed between adjacent stabilizer pads 50. As a result, stabilizer pads 52 and support arms 70 installed within pockets 48 will be spaced radially from each other around the exterior of bit body 30.

Drill bit 20 may be used to form a borehole having a nominal diameter or gauge diameter which corresponds generally with the combined diameter of gauge face surfaces 98 of cutter cone assemblies 90 at the area of contact with the inside diameter of the borehole. The approximate area of contact between gauge face surfaces 98 and the borehole is designated generally at 100 in FIGURE 1. Gauge face surfaces 98 of cutter cone assemblies 90 generally represent one of the components of drill bit 20 subject to substantial abrasion, erosion, and/or wear.

The number, configuration, dimensions and location of stabilizer pads 50 on the exterior of bit body 30 are preferably selected in accordance with teachings of the present invention to maximize stability of drill bit 20 within a borehole, to optimize fluid flow within the borehole adjacent to drill bit 20 and the annulus extending therefrom and/or to provide early indication of cutting structure wear. The number, configuration, dimensions and location of stabilizer pads 50 on the exterior of bit body 30 are preferably selected in accordance with teachings of the present invention to minimize scoring and/or plowing of the sidewall while tripping drill string 22 and drill bit 20 in and out of the borehole. Drill bit stability, fluid flow adjacent

to the drill bit and through the annulus extending therefrom and scoring or plowing of the sidewall are of particular concern while drilling horizontal and/or highly deviated boreholes.

5 For some applications during normal downhole drilling conditions, exterior surfaces 52 of stabilizer pads 50 may be spaced from the sidewall of a borehole by a nominal distance in the range of approximately 0.03 inches to 0.09 inches. Contact between exterior surfaces
10 52 of stabilizer pads 50 and adjacent portions of the sidewall will generally only occur during specific downhole drilling conditions such as excessive wear of the cutting structure associated with drill bit 20. Various surfaces of stabilizer pads 50 may be protected
15 by inserts, compacts and/or hardfacing which will be described later in more detail.

 For the embodiment of the present invention as shown in FIGURES 1, 2 and 3, pockets 48 and their respective support arms 70 are preferably radial spaced
20 approximately one hundred twenty degrees from each other on the exterior of bit body 30. Stabilizer lugs 50 are also preferably spaced radially approximately one hundred twenty degrees with each other. Each stabilizer pad 50 projects radially outward from bit body 30 intermediate
25 respective support arms 70. The combined outside diameter of support arm 70 is generally less than the combined outside diameter of stabilizer pads 50.

 For some applications, the combined outside diameter of support arms 70 may be approximately one-eighth of an
30 inch (.125") less than the gauge diameter of drill bit 20. As a result, any contact between the exterior of bit body 40 and the size wall of an associated borehole will

generally occur on exterior surfaces 52 of stabilizer pads 50 and not along the exterior surfaces of the associated support arms 70. Thus, support arms 70 and components disposed therein, such as a lubricant reservoir will be protected from contact with the sidewall of an associated borehole.

A plurality of fluid flow channels 54 are formed on the exterior of bit body 30 between each stabilizer pad 50 and adjacent support arms 70. Fluid flow channels 54 extend generally longitudinally from lower portion 38 to upper portion 34 of bit body 30. Fluid flow channels 54 cooperate with each other to direct turbulent fluid flow and cuttings from the bottom of the borehole upwardly into the annulus 26. One of the benefits of placing stabilizer pads 50 intermediate support arms 70 is increased separation of turbulent fluid in the vicinity of cutter cone assemblies 90 at the bottom of the borehole from generally upward fluid flow in the annulus above drill bit 20.

As shown in FIGURE 1, stabilizer pads 50 may be protected by a plurality of inserts or compacts 56 and 58 disposed in exterior surface 52 and hardfacing layers 60. Inserts 56 are preferably disposed in each stabilizer pad 50 adjacent to top surface 62. For some applications inserts 56 may have a cutting element typically associated with fixed cutter drill bits. The dimensions and configuration of inserts 56 may be selected such that the combined outside diameter of inserts 56 on respective stabilizer pads 50 corresponds approximately with the gauge diameter of drill bit 20. As a result, inserts 56 may be used to maintain the desired nominal diameter of the associated borehole.

Various types of cutting elements such as polycrystalline diamond compacts (PDC) may be used as inserts 56. U.S. Patent 5, 558,170 entitled *Method and Apparatus for Improving Drill Bit Stability* provides information concerning PDC type cutting elements. U.S. Patent 4,784,023 entitled *Cutting Element Having Composite Formed of Cemented Carbide Substrate and Diamond Layer and Method of Making Same* provides additional information concerning cutting elements which may be used with stabilizer pads in accordance with teachings of the present invention.

For some applications, PDC inserts or other types of cutting elements may be installed within top surface 62, leading surface 64 and/or bottom surface 68. Installing cutting elements in top surface 62, leading surface 64 and/or bottom surface 68 of stabilizer pads 50 will assist in maintaining the desired nominal diameter of an associated wellbore while tripping drill bit 20 and drill string 22 in and out of the associated wellbore. For some applications, drill string 22 may be rotated at the well surface while removing drill bit 20 from the wellbore.

Hardfacing layers 60 may be disposed on leading surface 64, trailing surface 66, top surface 62 and/or bottom surface 68. Hardfacing layers 60 may comprise, for example, chips or particles of tungsten carbide or other appropriate material for resisting erosion, abrasion and wear. For some applications, a layer of hardfacing may also be formed on exterior surface 52 and inserts or compacts 56 and 58 may be disposed within portions of top surface 62, leading surface 64, trailing surface 66 and/or bottom surface 68 as desired.

Drill string 22 preferably rotates drill bit 20 to the right to form a borehole while drilling fluid is ejected from nozzle openings 32 toward the bottom of the borehole. Arrow 72 in FIGURES 2 and 3 shows the normal direction of rotation for bit body 30. As shown in FIGURES 2 and 3, each stabilizer pad 50 includes leading surface 64 and trailing surface 66 disposed on opposite sides of exterior surface 52. Thus, each stabilizer pad 50 at leading surface 64 will contact cuttings and fluids from the bottom of the borehole. The fluid and cuttings move up along leading surface 64 within fluid flow channel 54 and flow upward into the associated annulus toward the well surface. Fluid flow channels 54 are defined in part by respective leading surfaces 64 of stabilizer pads 50 and respective exterior surfaces 102 of adjacent support arms 70.

Top surface 62 and bottom surface 68 of each stabilizer pad 50 may be slope generally outward from bit body 30 to exterior surface 52 of stabilizer pads 50. Top surface 62 and bottom surface 68 may comprise a flat surface, a concave surface, or any other appropriate configuration to aid in removal of cuttings and other debris from a borehole and to minimize scoring or plowing of the adjacent sidewall while tripping drill string 22.

The configuration and dimension of stabilizer pads 50 may be varied without departing from the teachings of the present invention. For example, stabilizer pads 50 may have linear slopes along leading surface 64 and trailing surface 68. Alternatively, stabilizer pads 50 may have nonuniform slopes and/or varying widths across exterior surface 52, top surface 62, leading surface 64, trailing surface 66 and bottom surface 68.

For some applications, it may be desirable to install one or more inserts on leading surface 64 adjacent to fluid flow channel 54. Also, inserts may be installed within top surface 62 and bottom surface 68.

5 Various types of inserts or compacts may be satisfactorily used including, but are not limited to, tungsten carbide inserts, polycrystalline diamond inserts, cubic boron nitride inserts and other types of inserts formed from hard materials compatible with the
10 associated downhole drilling environment.

For some applications, inserts and compacts having high abrasion, erosion and/or wear resistance will preferably be installed within selected portions of stabilizer pads 50. For other applications, inserts
15 having various types of cutting elements or cutting structures may be installed in selected portions of stabilizer pads 50. The type of inserts and/or compacts selected for use with stabilizer pads 50 will depend upon anticipated downhole drilling conditions and the cutting
20 structure of the associated drill bit.

FIGURE 4 is a schematic drawing showing an isometric view of a rotary cone drill bit indicated generally at 120, incorporating various teachings of the present invention. Drill bit 120, sometimes referred to as a
25 roller cone drill bit or a rotary rock bit, may be attached to drill string 22 (shown in dotted lines) and disposed within a borehole (not expressly shown). An annulus (not expressly shown) is formed between the exterior of drill string 22 and the inside diameter or
30 side wall of the borehole.

For the embodiment shown in FIGURES 4 and 5, drill bit 120 preferably includes one piece or unitary bit body

130. Upper portion 34 of bit body 120 includes threaded connection or pin 36 adapted to secure bit body 130 with drill string 22. Two support arms 170 are preferably attached to and extend from bit body 130 opposite from threaded connection 36. Support arms 170 and attached cutter cone assemblies 190 may have substantially the same design and configuration as previously described support arms 70 and cutter cone assemblies 90.

Since drill bit 120 includes only two support arms and cutter cone assemblies, support arms 170 and attached cutter cone assemblies 190 may be substantially larger than support arms 70 and cutter cone assemblies 90 for a drill bit having the same nominal or gauge diameter. Stabilizer pads 150 on drill bit 120 may also be substantially larger than stabilizer pads 50 on the exterior of drill bit 20 even though both drill bit 20 and 120 may have substantially the same gauge diameter.

Some of the advantages of a two cone drill bit such as drill bit 120 include a larger cutting structure and larger bearing system for each cutter cone assembly as compared to a three cone drill bit having the same nominal diameter or gauge diameter. Disadvantages of a two cone drill bit include relative instability as compared to a three cone drill bit having the same nominal diameter or gauge diameter. Two cone drill bits may sometimes have a tendency to wobble or become unstable at the bottom of a borehole. Therefore, stabilizer pads 150 are particularly beneficial for use with drill bit 120 having only two support arms 170 and attached cutter cone assemblies 190.

Bit body 130 includes lower portion 138 having a generally convex exterior surface 140 formed thereon.

For the embodiment of the present invention as shown in FIGURES 4 and 5, bit body 130 preferably includes four openings 132 and respective fluid passageways (not expressly shown). As previously discussed with respect to drill bit 20, various types of nozzles may be installed within openings 132. Bit body 130 also includes middle portion 144 disposed between upper portion 34 and lower portion 138.

Longitudinal axis or central axis 146 extends through bit body 130 and corresponds generally with a projected axis of rotation for drill bit 120. Middle portion 144 preferably has a general cylindrical configuration with a pair of pockets (not expressly shown) formed in the exterior thereof and spaced radially from each other.

Each cutter cone assembly 190 preferably includes a plurality of inserts 92 which scrape and gouge against the sides and bottom of a borehole in response to weight and rotation applied to drill bit 120 by drill string 22. Other types of cutter cone assemblies and cutting structures may be satisfactorily used with the present invention including, but not limited to, cutter cone assemblies having milled teeth instead of inserts 92. A plurality of surface compacts (not expressly shown) are preferably disposed in gauge face surface 198 of each cutter cone assembly 190.

Drill bit 120 may be used to form a borehole having a nominal diameter or gauge diameter which corresponds generally with the combined diameter of gauge face surfaces 198 of cutter cone assemblies 190 at the area of contact with the inside diameter of the borehole. Dotted

line 200 as shown in FIGURE 5 corresponds with the gauge diameter of drill bit 120.

5 A pair of stabilizer pads 150 are formed on the exterior of bit body 130 as integral components thereof in accordance with teachings of the present invention. Stabilizer pads 150 preferably extend radially from bit body 130 a distance which is slightly less than the desired radius or gauge diameter of the associated borehole. Dotted line 202 represents the combined
10 outside diameter corresponding with exterior surfaces 152 of stabilizer pads 150.

The number, configuration, dimensions and locations of stabilizer pads 150 on the exterior of bit body 130 are preferably selected in accordance with teachings of
15 the present invention to maximize stability of drill bit 120 within a borehole, to optimize fluid flow within the borehole adjacent to drill bit 120 and the annulus extending therefrom and/or to provide early indication of cutting structure wear. The number, configuration,
20 dimensions and location of stabilizer pads 150 on the exterior of bit body 130 are also preferably selected in accordance with teachings of the present invention to minimize scoring and/or plowing of the sidewall while tripping drill string 22 and drill bit 120 in and out of
25 a borehole. Stabilizer pads 150 may be formed as integral components of bit body 130 using the same techniques and procedures as previously described with respect to stabilizer pads 50 and bit body 30.

For some applications, exterior surfaces 152 of
30 stabilizer pads 150 will normally be spaced from the sidewall of a borehole by a nominal distance in the range of approximately 0.03 inches to 0.09 inches. The distance

between dotted lines 202 and 200 shown in FIGURE 5 is enlarged for purposes of illustrating various features of the present invention.

For the embodiment of the present invention as shown in FIGURES 4 and 5, support arms 170 are preferably spaced approximately one hundred and eighty degrees (180°) from each other on the exterior of bit body 130. Stabilizer pads 150 are preferably spaced radially approximately one hundred and eighty degrees (180°) from each other intermediate respective support arms 170. The increased radial spacing between support arms 170 provides more area for installation of stabilizer pads 150.

A plurality of fluid flow channels 154 are formed on the exterior of bit body 130 between each stabilizer pad 150 and adjacent support arms 170. Fluid flow channels 154 extend from lower portion 138 to upper portion 34 of bit body 130.

For the embodiment shown in FIGURES 4 and 5, each stabilizer pad 150 includes leading surface 164, trailing surface 166 disposed on opposite sides of exterior surface 152. Leading surfaces 164, trailing surfaces 166 and exterior surfaces 152 are preferably disposed at an angle relative to longitudinal axis 146. As a result stabilizer pads 150 have a generally spiral shaped configuration relative to the exterior of bit body 130.

Exterior surfaces 152 of stabilizer pads 150 have a generally rectangular configuration. However, by forming stabilizer pads 150 with a generally spiral shaped configuration as shown in FIGURES 4 and 5, the effective width of the portion each stabilizer pad 150 which may contact an adjacent sidewall is substantially increased

as compared to the width of the respective exterior surface 152. For some applications, a spiral shaped stabilizer pad may have an effective width between one and one-half and two times the width of the associated exterior surface.

Forming stabilizer pads with a generally spiral shaped configuration optimizes the fluid flow path for moving drilling fluid with entrained cuttings from beneath the associated drill bit to an annulus extending thereabove and significantly increases the total surface area of the associated stabilizer pad which may be engaged with the inside diameter or sidewall of an associated borehole. Increasing the effective surface area of those portions of a stabilizer pad which may contact the sidewall of a borehole provides greater downhole stability and greater torque feedback at the well surface to indicate erosion and/or wear of the associated cuttings structure.

When drill string 22 rotates drill bit 120, leading surface 164 will function similar to a ramp to lift drilling fluids and cuttings from the bottom of a borehole and direct movement of the drilling fluids and cuttings longitudinally upward into the annulus. Fluid flow channels 154 are defined in part by respective leading surfaces 164 of stabilizer pads 150 and respective exterior surfaces 172 of support arms 170.

As previously noted, stabilizer pads 50 and 150 are preferably manufactured as integral components of respective bit bodies 30 and 130. For some applications, stabilizer pads 50 and 150 may be manufactured with only pockets or openings to receive corresponding inserts and compacts which are not installed during initial

manufacture and assembly of the associated drill bit. By not installing inserts and compacts during initial manufacture drill bits 20 and 120, it is possible to grind off or alter the configuration of stabilizer pads 50 and 150 at a field location prior to using the associated drill bit. Also, inserts and compacts made from various types of material, appropriate for specific downhole drilling environment, may be installed at a field location.

During normal downhole drilling conditions, drill bit 20 will generally contact the sidewall of a borehole at three separate locations corresponding approximately with area 100 on respective gauge face surfaces 98. The dimensions and configuration of stabilizer pads 50 are preferably selected such that any additional contact between drill bit 20 and the sidewall of the borehole will occur on respective exterior surfaces 52. As previously noted, stabilizer pads 50 are preferably radially offset from each other and radially offset from respective support arms 70. Also, stabilizer pads 50 are longitudinally spaced from respective gauge face surfaces 98. Therefore, incorporating stabilizer pads 50 as an integral component of bit body 30 provides three additional possible contact areas between the exterior of drill bit 20 and adjacent portions of a borehole. Since these additional contact areas are both radially and longitudinally spaced from gauge face surfaces 98, the downhole stability of drill bit 20 is substantially improved.

Stabilizer pads 150 also improve the downhole stability of drill bit 120 for substantially the same reasons. Stabilizer pads 150 increase the number of

contact areas between drill bit 120 and the sidewall of a borehole from two to four.

5 The total area of exterior surfaces 52 of stabilizer pads 50 and exterior surfaces 152 of stabilizer pads 150 are substantially larger than the area of contact between respective gauge face surfaces 98 and 198 with the sidewall of a borehole during normal downhole drilling conditions. As portions of the cutting structure associated with cutter cone assemblies 90 and 190 erode and/or wear, the inside diameter of the associated
10 borehole will decrease until stabilizer pads 50 or 150 contact the respective sidewall.

Since the area of exterior surfaces 52 and 152 is substantially larger than the area of contact associated with gauge face surfaces 98 and 198 and the respective
15 sidewall during normal drilling operations, the torque load on attached drill string 22 will increase significantly. By carefully monitoring the torque load on drill string 22 at the well surface, stabilizer pads 50 and 150 will provide an early indication of erosion and/or wear of the cutting structure associated with
20 respective drill bits 20 and 120.

Often gauge face surfaces 98 and 198 will be the respective portions of drill bits 20 and 120 which
25 experience early erosion and wear. When the torque load on drill string 22 exceeds a selected value depending upon the size and type of drill bit and associated downhole drilling conditions, drill bit 20 and 120 will preferably be removed from the associated wellbore prior
30 to a more catastrophic failure of the respective drill bit or cutting structure.

For the embodiments of the present invention as shown in FIGURES 1-5, stabilizer pads 150 and 152 are disposed in a generally symmetrical configuration with respect to each other and respective support arms 70 and 170 and cutter cone assemblies 90 and 190. For some applications, it may be desirable to provide only two stabilizer pads 50 on the exterior of bit body 30 or only one stabilizer pad 150 on the exterior of bit body 130.

Forming nonsymmetrical stabilizer pads on the exterior of a bit body in accordance with teachings of the present invention may be beneficial for use in directional drilling of highly deviated and/or horizontal boreholes. Also, a nonsymmetrical configuration of stabilizer pads formed on the exterior of a bit body in accordance with teachings of the present invention may be used to increase fluid flow and the return of cuttings or other debris from the bottom of a borehole along one side of the associated drill bit. Thus, stabilizer pads may be formed as an integral component of a bit body to assist in directional drilling control and/or improved hydraulic performance of the associated drill bit.

Forming stabilizer pads as an integral component of a bit body with a nonsymmetrical configuration may be particularly beneficial when the associated drill bit is used in relatively soft formations which require removal of a high volume of drilling fluid and cuttings or other debris from the bottom of a borehole. Alternatively, the size of the stabilizer pads may be reduced to provide enlarged flow channels between each stabilizer pad and an adjacent support arm. For example, decreasing the width of stabilizer pads 50 will enlarge the flow area of fluid flow channels 54.

For the embodiments of the present invention as shown in FIGURES 1-5, exterior surfaces 52 and 152 of respective stabilizer pads 150 have a relatively uniform outside diameter relative to respective longitudinal axis 46 and 146. For some applications, stabilizer pads 50 and/or 150 may be formed with exterior surfaces 52 and 152 having a radius of curvature relative to respective longitudinal axis 46 and 146. Forming stabilizer pads with a radius of curvature may improve fluid flow and the return of cuttings during normal downhole drilling operations while providing sufficient contact area to stabilize the associated drill bit and/or to provide early indication of erosion and wear of the associated cutting structure.

For some applications, stabilizer pads 50 and/or 150 may be formed with exterior surfaces 52 and 152 having a generally tapered configuration. For applications such as deep highly deviated wellbores and/or wellbores having relatively long horizontal portions extending therefrom, the outside diameter of exterior surface 52 adjacent to bottom surface 68 may be larger than the outside diameter of exterior surface 52 adjacent to top surface 62. As a result of the difference in outside diameters, exterior surface 52 will have a generally tapered configuration to assist in pulling drill bit 20 from the bottom of a borehole.

Conventional rotary cone drill bits (not expressly shown are often constructed in two or three segments. The segments may be positioned together longitudinally with a welding groove disposed between each segment. The segments may then be welded with each other using conventional welding techniques to form the associated

bit body. Each segment also includes an associated support arm extending from the bit body. An enlarged cavity is typically formed in the bit body to receive drilling fluids from a drill string. U.S. Patent
5 4,054,772 entitled *Positioning System for Rock Bit Welding Shows a Method and Apparatus for Constructing a Three Cone Rotary Rock Bit from Three Individual Segments* shows one example of a conventional rotary cone drill bit.

10 The segments of a conventional drill bit are generally fabricated using forging techniques associated with the manufacture of oil and gas drilling and production equipment. One or more of the forged drill bit segments will typically include a nozzle boss (not
15 expressly shown). In accordance with teachings of the present invention a stabilizer pad or lug may be also included as an integral component of individual forged segments. By providing stabilizer pads as integral components of the forged segments, the number, size,
20 location, and orientation of the resulting stabilizer pads and nozzles may be optimized for the resulting drill bit substantially the same as previously described for drill bits 20 and 120.

25 Although the present invention and its advantages have been described in detail, it should be understood that various changes, substitutions and alterations can be made therein without departing from the spirit and scope of the invention as defined by the appended claims.

WHAT IS CLAIMED IS:

1. A drill bit for forming a borehole, comprising:
a bit body having an upper portion adapted for
5 connection to a drill string for rotation of the drill
bit;
a number of support arms extending from the bit
body;
a number of cutter cone assemblies equal to the
10 number of support arms;
each cutter cone assembly rotatably mounted on one
of the support arms;
at least two stabilizer pads formed as integral
components of the bit body and projecting radially
15 outward from the bit body; and
the stabilizer pads spaced radially from each other
with one of the support arms disposed therebetween.
2. The drill bit of Claim 1 further comprising
20 each of the stabilizer pads having a leading surface, a
trailing surface, and an exterior surface disposed
therebetween.
3. The drill bit of Claim 1, wherein each
25 stabilizer pad comprises a layer of hardfacing material.
4. The drill bit of Claim 1, wherein each
stabilizer pad comprise a plurality of inserts disposed
therein.

30



5. The drill bit of Claim 1 further comprising:
the cutter cone assemblies cooperating with each
other to define in part a gauge diameter for the drill
bit; and

5 the stabilizer pads projecting from the bit body a
radial distance less than the gauge diameter of the drill
bit such that as other components of the drill bit wear
the stabilizer pads will contact adjacent portions of an
associated borehole and increase torque loads on the
10 drill string.

6. The drill bit of Claim 1 further comprising a
fluid flow channel formed on the exterior of the bit body
between each stabilizer pad and an adjacent support arm.

15 7. The drill bit of Claim 1, further comprising a
one piece, unitary bit body.

8. The drill bit of Claim 1 further comprising a
20 bit body formed from two or more segments with each
segment having a stabilizer pad and a support arm formed
as integral components thereof.

9. The drill bit of Claim 1 further comprising:
25 at least three stabilizer pads formed as integral
components of the bit body; and

the stabilizer pads spaced radially from each other
and from adjacent support arms to define respective fluid
flow channels between the stabilizer pads and the support
30 arms.



10. The drill bit of Claim 1 further comprising:
each stabilizer pad having an exterior surface with
a generally rectangular configuration; and
the exterior surface of each stabilizer pad disposed
generally parallel with a longitudinal axis extending
through the bit body.

11. The drill bit of claim 1 further comprising:
a longitudinal axis extending through the bit body
corresponding generally with a projected axis of rotation
for the drill bit; and
each stabilizer pad having an exterior surface
disposed at an angle relative to the longitudinal axis of
the bit body.

12. The drill bit of Claim 1 further comprising:
two stabilizer pads formed as integral components of
the bit body; and
the stabilizer pads disposed between adjacent
support arms to define respect fluid flow channels
between the stabilizer pads and the support arms.

13. The drill bit of Claim 12 further comprising:
a longitudinal axis extending through the bit body
corresponding generally with a projected axis of rotation
for the drill bit; and
each stabilizer pad having a generally spiral shaped
configuration relative to the longitudinal axis of the
bit body.



14. The drill bit of Claim 1 further comprising:
at least one PDC insert disposed within each
stabilizer pad; and
each PDC insert having a cutting structure for
5 engagement with adjacent portions of a sidewall of the
borehole.



15. A bit body for a drill bit comprising:

at least two stabilizer pads formed as integral components of the bit body during initial manufacture thereof;

5 each stabilizer pad having a leading surface, a trailing surface and an exterior surface formed therebetween; and

each stabilizer pad projecting radially from the bit body.

10

16. The bit body of Claim 15, further comprising each stabilizer pad having a bottom surface inclined at an angle extending from the bit body to the exterior surface of the stabilizer pad.

15

17. The bit body of Claim 15 further comprising each stabilizer pad having a top surface inclined at an angle extending from the bit body to the exterior surface of the stabilizer pad.

20

18. The bit body of Claim 15, wherein each stabilizer pad further comprises a layer of hardfacing disposed thereon.

25

19. The bit body of Claim 15, further comprising a plurality of inserts disposed in each stabilizer pad.



20. A rotary cone drill bit for forming a borehole, comprising:

a bit body having an upper portion adapted for connection to a drill string for rotation of the bit body;

three support arms extending from the bit body;

three cutter cone assemblies respectively mounted on one of the support arms;

three stabilizer pads formed as integral components of the bit body;

each stabilizer pad projecting radially outward from the bit body;

the bit body having a longitudinal axis corresponding generally with the projected axis of rotation for the drill bit;

each stabilizer pad spaced radially from each other on the exterior of the bit body; and

each support arm spaced radially from each other and disposed between respective stabilizer pads.

21. The drill bit of claim 20 further comprising: each stabilizer pad having a leading surface; and a plurality of inserts installed within the leading surface of each stabilizer pad.

22. The drill bit of claim 20 further comprising: each stabilizer pad having an exterior surface; and a plurality of inserts installed within the exterior surface of each stabilizer pad.



23. The drill bit of claim 20 further comprising:
each stabilizer pad having a leading surface, an
exterior surface, a trailing surface, a top surface and a
bottom surface; and

5 a layer of hardfacing disposed on selected portions
of the leading surface, exterior surface, trailing
surface, a top surface and a bottom surface.

24. The drill bit of Claim 20 further comprising:
10 each stabilizer pad having a leading surface, an
exterior surface, a trailing surface, a top surface, and
a bottom surface; and

a plurality of inserts installed within selected
portions of the leading surface, exterior surface,
15 trailing surface, top surface, and bottom surface.

