

1 Managed Pressure Drilling System and Method of Use

2

3 The present invention relates to a Managed Pressure Drilling (MPD) system and method
4 of use and in particular to drill pipe assemblies for use in managed pressure drilling
5 operations. Particular aspects of the invention relate to managed pressure drilling for
6 onshore and offshore wells.

7

8 Background to the invention

9

10 Drilling operations typically use a rotating drill bit on the end of a drill string. Managed
11 Pressure Drilling (MPD) is a form of drilling where the annular pressure throughout a
12 wellbore is precisely controlled.

13

14 In MPD operations the annular pressure is kept slightly above the pore pressure to prevent
15 the influx of formation fluids into the wellbore, but it is maintained below the fracture
16 initiation pressure. The dynamic control of annular pressures in managed pressure drilling
17 enables a well to be drilled in conditions where the local geology makes conventional
18 drilling difficult or impossible.

19

20 Mud is pumped down the drill string from a mud pumping system and returned to the
21 surface flowing in the annulus between the drill string and the well to allow sand and
22 cuttings to be removed from the well. The mud circulation system is a closed loop with
23 returning mud flowing into manifolds that can apply backpressure. The annulus is sealed
24 around the drill string while the drill string rotates typically using a rotating control device
25 (RCD). The MPD process may additionally or alternatively control mud density, annular
26 fluid level adjustment or circulating friction.

27

28 Conventional rotating control devices comprise an internal sealing element which seals
29 around the outside diameter of the drill string and rotates with the drill string during drilling.
30 As the wellbore is drilled the drill string is run through the RCD. The continuous movement
31 of the drill string through the sealing element of the RCD causes wear of sealing surface of
32 the sealing element.

33

1 The sealing elements are required to be regularly replaced to maintain an effective seal.
2 The replacement of the sealing element results in a loss of rig drilling time and poses
3 safety issues to rig personnel.

4
5 MPD systems have proven effective in different well types including vertical, horizontal,
6 deviated and unconventional well designs in offshore and onshore environments. Typically
7 drill strings are required to be strong and flexible to allow drilling of horizontal, highly
8 deviated and long reaching bores.

9
10 Summary of the invention

11
12 There is need for a drill pipe apparatus which addresses one or more of the problems
13 associated with known prior art systems, including those identified above.

14
15 It is amongst the aims and objects of the invention to provide a drill pipe apparatus for
16 managed pressure drilling which prevents or mitigates wear of annular seals or seal
17 elements.

18
19 It is a further object of the present invention to provide a method of performing managed
20 pressure drilling in deviated or horizontal wells which mitigates the frequency with which
21 annular seals or seal elements are worn and require replacement.

22
23 According to a first aspect of the invention, there is provided a managed pressure drilling
24 system for use in managed pressure drilling operations, the system comprising:
25 a rotating sealing device; and
26 a drill string comprising a plurality of drill pipe members arranged in at least a first drill
27 string section and a second drill string section;
28 wherein each drill pipe members comprises a first tool joint having a first tool joint outer
29 diameter;
30 a second tool joint having a second tool joint outer diameter; and
31 a tubular body between the first and second tool joints having a tubular body outer
32 diameter,
33 wherein the first tool joint outer diameter and second tool joint outer diameter are larger
34 than the tubular body outer diameter in each of the drill pipe members in the first drill string
35 portion;

1 wherein the first tool joint outer diameter and the second tool joint outer diameter are
2 substantially the same as the tubular body outer diameter in each of the drill pipe members
3 in the second drill string section; and
4 wherein the rotating sealing device is configured to form a fluid seal against an outer
5 surface of the second drill string section.

6
7 Preferably the first and second tool joints of the drill pipe members in the second drill string
8 section are flush with the outer surfaces of the drill pipe member tubular body . The first
9 and second tool joints of the drill pipe members in the second drill string section may have
10 substantially the same diameter than the tubular body diameter of the drill pipe members.

11
12 The first tool joint and/or the second tool joint in each of the drill pipe members in the first
13 drill string portion may have an upset. The upset may be an external and/or internal upset.
14 The outer diameter of the upset may be larger than the tubular body outer diameter in
15 each the drill pipe members in the first drill string section.

16
17 The first tool joint and/or the second tool joint in each of the drill pipe members in the
18 second drill string portion may have an internal upset. The internal upset may be
19 configured to not extend the outer diameter of the first tool joint and/or the second tool joint
20 in each of the drill pipe members in the second drill string section beyond the tubular body
21 outer diameter in each drill pipe members in the second drill string section.

22
23 The first and/or second tool joints of the drill pipe members in the first drill string portion or
24 section may protrude or extend beyond the outer surfaces of the drill pipe members such
25 as the tubular body outer diameter in each drill pipe members in the first drill string section.
26 The first and/or second tool joints of the drill pipe members in the first drill string section
27 may have a larger outer diameter than the tubular body diameter of the drill pipe members
28 in the first drill string section.

29
30 The rotary sealing device may be configured to form a fluid seal against at least a part of
31 an outer surface of the second drill string section.

32
33 By providing a second drill string section having drill pipe members with tool joints which
34 are substantially the same diameter as the main tubular body and a first drill string section
35 with each drill pipe members having tool joints with a larger diameter than the main tubular

1 body (such as having an upset), the invention may facilitate the drilling of wells that deviate
2 from the vertical while maintaining a robust effective seal around a surface of the second
3 drill string section.

4

5 The second drill string section may be configured to be located in a substantially vertical
6 portion or section of the wellbore bore in a well, riser, liner and/or casing. The second drill
7 string section may be configured to be located in a substantially non-horizontal or non-
8 deviated portion or section of the wellbore bore in a well, riser, liner and/or casing.

9

10 The first drill string section may be connected to a drill bit. The first drill string section may
11 be configured to be located in a substantially non-vertical portion or section of the wellbore
12 to allow the drill bit connected at a lower end of the first drill string section to drill in a
13 deviated or horizontal well. The first drill string section may be configured to be located in a
14 deviated or substantially horizontal portion or section of the wellbore. The first drill string
15 section may be configured to be located in a substantially S-shaped portion or section of
16 the wellbore.

17

18 The rotating sealing device may be a surface pressure control device such as a rotary
19 control device (RCD). The rotary control device may comprise at least one sealing element
20 configured to contact, form and/or maintain a fluid seal against at least one drill pipe
21 member in the second drill string section or a part of at least one drill pipe member in the
22 second drill string section. The RCD may contact an outer surface of a part of the second
23 drill string section to form a seal.

24

25 The second drill string section may have a generally smooth surface without any
26 protruding or irregular surfaces from tool joints, upsets and/or drill collars. The continuous
27 outer surface diameter of the second drill string section along its longitudinal length may
28 enable sealing elements in an RCD to maintain a robust effective seal around a surface of
29 the second drill string section. The continuous outer surface diameter of the second drill
30 string section along its longitudinal length may enable sealing elements in an RCD to
31 maintain a robust effective seal around a surface of the second drill string section as the
32 second drill string section is raised and/or lowered through the RCD.

33

34 By providing a second drill string section with flush tool joints, the second drill string
35 section or part thereof may be moved through the RCD and/or through the sealing element

1 during a drilling operation while the sealing element is under pressure and mitigating
2 damage or wear to an interior sealing surface of the sealing element. The lifespan of the
3 sealing element may be extended and a long term seal be maintained. The RCD may be
4 configured to operate in annular wellbore fluid pressures in the range of 2000 psi to 10000
5 psi.

6
7 The first tool joint of the drill pipe members in the first and/or second drill string sections
8 may be a box section and the second tool joint of the drill pipe members in the first and/or
9 second drill string sections may be a pin section. Alternatively, the first tool joint may be a
10 pin section and the second tool joint may be a box section.

11
12 Preferably the second drill string section has an outer diameter that is substantially uniform
13 along its longitudinal length.

14
15 Each drill pipe member of the first drill string section may have opposite longitudinal first
16 and second ends and a middle portion extending between the first and second ends. The
17 first and second ends may have a first outer diameter and the middle portion having a
18 second outer diameter less than the first outer diameter.

19
20 The rotating sealing element may be configured to seal around an outer diameter of part of
21 the second drill string section and rotate with the second drill string section.

22
23 One end of the second drill string section may be configured to be connected to one end of
24 the first drill string section. Preferably a lower end of the second drill string section may be
25 configured to be connected to an upper end of the first drill string section.

26
27 The term "lower end" refers to the portion of the drill string section located at a downhole
28 end of the drill string section. The term "upper end" refers to the portion of the drill string
29 section located at an uphole end of the drill string section.

30
31 A first or second tool joint of the second drill string section may be connectable to a first or
32 second tool joint of the first drill string section to connect the first and second drill string
33 sections together.

34

1 The first drill string section may be located further downhole than the second drill string
2 section. The first drill string section may be a lower drill string section. The second drill
3 string section may be an upper drill string section.

4

5 A third or further drill string section may be connected to the second drill string section.

6 The third or further drill string section may comprise a plurality of drill pipe members having
7 first tool joint with a first tool joint outer diameter, a second tool joint having a second tool
8 joint outer diameter; and a tubular body between the first and second tool joints having a
9 tubular body outer diameter. The first tool joint outer diameter and second tool joint outer
10 diameter of the third or further drill string may be larger than the tubular body outer
11 diameter of the drill pipe member in the third or further drill string section.

12

13 Alternatively, the first tool joint outer diameter and the second tool joint outer diameter of
14 the third or further drill string may be substantially the same diameter as the tubular body
15 outer diameter in each drill pipe members. A third or further drill string section may have
16 an outer diameter that is substantially uniform along its longitudinal length.

17

18 According to a second aspect of the invention, there is provided a managed pressure
19 drilling system for use in managed pressure drilling operations, the system comprising:
20 a rotating sealing device; and

21 a drill string comprising a plurality of drill pipe members wherein each drill pipe member
22 has a first tool joint having a first tool joint outer diameter;

23 a second tool joint having a second tool joint outer diameter; and

24 a tubular body between the first and second tool joints having a tubular body outer
25 diameter;

26 wherein the first tool joint outer diameter, the second tool joint outer diameter and the
27 tubular body outer diameter are substantially the same; and

28 wherein the rotating sealing device is configured to form a fluid seal against the drill string.

29

30 The rotating sealing device may be configured to form a fluid seal against at least part of a
31 drill pipe member of the drill string. The rotating sealing device may be configured to
32 operate in annular wellbore fluid pressures in the range of 2000 psi to 10000 psi.

33

34 The rotating sealing device may be a rotary control device (RCD). The rotary control
35 device may comprise at least one sealing element configured to form and maintain a fluid

1 seal against at least one surface of the drill string. The at least one sealing element may
2 be configured to form and maintain a fluid seal against at least one part of the drill string.

3

4 The drill string may be an upper drill string section. The drill string may be connectable to a
5 lower drill string connected to a drill bit. The drill string may be configured to connected to
6 a lower drill string. The lower drill string may be configured to be connected to a drill bit at
7 one end.

8

9 The lower drill string may comprise a plurality of drill pipe members wherein each drill pipe
10 member has a first tool joint having a first tool joint outer diameter;
11 a second tool joint having a second tool joint outer diameter; and
12 a tubular body between the first and second tool joints having a tubular body outer
13 diameter; wherein the first tool joint outer diameter and the second tool joint outer diameter
14 of the lower drill string may be larger than the tubular body outer diameter.

15

16 Alternatively the first tool joint outer diameter and/or the second tool joint outer diameter
17 may be smaller than the tubular body outer diameter in the lower drill string.

18

19 The drill string may be connectable to an upper drill string. The drill string may be
20 configured to connected to an upper drill string. The upper drill string may be configured to
21 be connected to the drill string at one end. The upper drill string may have a generally
22 constant outer diameter along its longitudinal length. The outer diameter of the lower drill
23 string along its longitudinal length may vary due to protrusions at the joint connections.

24

25 Embodiments of the second aspect of the invention may include one or more features of
26 the first aspect of the invention or its embodiments, or vice versa.

27

28 According to a third aspect of the invention, there is provided a drill string assembly for
29 managed pressure drilling comprising:

30 a plurality of drill pipe members arranged in a first drill string section and a second drill
31 string section;

32 wherein each drill pipe member has a first tool joint having a first tool joint outer diameter;

33 a second tool joint having a second tool joint outer diameter;

34 a tubular body between the first and second tool joints having a tubular body diameter;

1 wherein the first tool joint outer diameter and second tool joint outer diameter of each drill
2 pipe member in the second drill string section are substantially equal to the tubular body
3 diameter in each drill pipe member in the second drill string section; and
4 wherein the first tool joint outer diameter and/or second tool joint outer diameter of each
5 drill pipe member in the first drill string section is larger than the tubular body diameter in
6 each the drill pipe member in the first drill string section.

7
8 The first tool joint of the drill pipe members in the first and/or second drill string sections
9 may be a box section and the second tool joint of the drill pipe members in the first and/or
10 second drill string sections may be a pin section. Alternatively, the first tool joint may be a
11 pin section and the second tool joint may be a box section.

12
13 The first tool joint and/or second tool joint in each drill pipe member in the first drill string
14 section may have an upset. The upset may be an external and/or an internal upset.
15 The first tool joint and/or second tool joint in each drill pipe member in the second drill
16 string section may have an internal upset.

17
18 The second drill string section may be configured to be substantially vertical. The second
19 drill string section may be configured to be used in a substantially vertical section of a well.
20 In an offshore managed pressure drilling operation the second drill string section may be
21 contained within a riser such as a marine riser. In an onshore managed pressure drilling
22 operation the second drill string section may be contained within an upper casing or liner.

23
24 The first drill string section may be configured to be located further downhole than the
25 second drill string section. The first drill string section may be a lower drill string section.
26 The second drill string section may be an upper drill string section. The first drill string
27 section may be configured to be used in a substantially horizontal or deviated section of a
28 well.

29
30 Embodiments of the third aspect of the invention may include one or more features of the
31 first or second aspects of the invention or their embodiments, or vice versa.

32
33 According to a fourth aspect of the invention, there is provided a drill string assembly for
34 managed pressure drilling comprising:

1 a plurality of drill pipe members wherein each drill pipe members has a first tool joint
2 having a first tool joint outer diameter;
3 a second tool joint having a second tool joint outer diameter; and
4 a tubular body between the first and second tool joints having a tubular body outer
5 diameter;
6 wherein the first tool joint outer diameter and the second tool joint outer diameter are
7 substantially equal to the tubular body outer diameter in each drill pipe member in the drill
8 string or at least one section of the drill string, wherein the drill string or at least one
9 section of the drill string has a substantially constant outer diameter along its length.

10

11 The drill string and/or drill pipe members may have a constant outer diameter without any
12 protruding or irregular surfaces from tool joints or drill collars. The continuous outer surface
13 diameter of the drill string along its longitudinal length may enable sealing elements in an
14 RCD to maintain a robust effective seal around a portion of the drill string without an
15 obstruction or damage to sealing elements in the RCD.

16

17 The drill string may comprise drill pipe members with a substantially constant outer
18 diameter which may be moved and passed through a sealing element of an RCD, such as
19 during a drilling operation, while the sealing element is under pressure. As there are no
20 protruding or irregular surfaces from tool joints, upsets or drill collars, damage or wear to
21 the interior sealing surface of the sealing element may be mitigated.

22

23 The drill string may be arranged into two or more sections. The drill string may comprise at
24 least one section of the drill string having a first tool joint outer diameter, the second tool
25 joint outer diameter and tubular body outer diameter which are substantially the same is an
26 upper or second drill string section. The drill string may comprise a lower or first drill string
27 section wherein the first tool joint outer diameter and/or the second tool joint outer
28 diameter is larger than the tubular body outer diameter in each drill pipe member in the
29 lower or first drill string section. The drill string may comprise a second or upper drill string
30 section having a first tool joint outer diameter, the second tool joint outer diameter and
31 tubular body outer diameter which are substantially the same.

32

33 Embodiments of the fourth aspect of the invention may include one or more features of the
34 first to third aspects of the invention or their embodiments, or vice versa.

35

1 According to a fifth aspect of the invention, there is provided a managed pressure drilling
2 system for use in managed pressure drilling operations, the system comprising:
3 a rotating sealing device; and
4 a drill string comprising a plurality of drill pipe members arranged in at least a first drill
5 string section and a second drill string section;
6 wherein each of drill pipe members has a tubular pipe body with connectors at either end
7 thereof for connection to adjacent drill pipe members;
8 wherein the connectors and the tubular pipe body of the drill pipe member in the second
9 drill string section have substantially the same outer diameter; and
10 wherein the connectors of the drill pipe members in the first drill string section have an
11 outer diameter which is larger than the outer diameter of the tubular pipe body of the drill
12 pipe members in the first drill string section; and
13 wherein the rotating sealing device is configured to form a fluid seal against an outer
14 surface of at least part of the second drill string section.

15

16 The connectors may be tool joints. The connectors may be a box section at a first end of
17 the drill pipe member and a pin section at a second end of the drill pipe member.

18

19 Embodiments of the fifth aspect of the invention may include one or more features of the
20 first to fourth aspects of the invention or their embodiments, or vice versa.

21

22 According to a sixth aspect of the invention, there is provided a managed pressure drilling
23 system for use in managed pressure drilling operations, the system comprising:
24 a rotating sealing device; and
25 a drill string comprising a plurality of drill pipe members;
26 wherein each drill pipe member comprises;
27 a tubular body;
28 a pin section at a first end of the tubular body; and
29 a box section at the second end of the tubular body;
30 wherein the pin section and box section are configured for coupling to an adjacent drill
31 pipe member and wherein the outer diameters of the tubular body, pin section and box
32 section are substantially the same; and
33 the rotating sealing device is configured to form a fluid seal against the drill string passing
34 through the rotating sealing device.

35

1 The drill string may be connected to a drill bit. The drill string may be arranged into at least
2 a first drill string portion and a second drill string portion.

3

4 Preferably the drill string is an upper drill string which may be connectable to a lower drill
5 string connected to a drill bit. The drill string may be an upper drill string which may be
6 configured to be connected to a lower drill string. The lower drill string may be configured
7 to be connected to a drill bit. The lower drill string may comprise a plurality of drill pipe
8 members wherein each drill pipe members may comprise a tubular body, a pin section at a
9 first end of the tubular body; and a box section at the second end of the tubular body. At
10 least one of the pin section outer diameter or the box section outer diameter may be larger
11 or smaller than the tubular body outer diameter in the lower drill string.

12

13 The rotating sealing device may be configured to engage with an outside surface of part of
14 a drill pipe member of the upper drill string so that flow of fluid between the rotating sealing
15 device and the drill pipe member of the upper drill string is substantially prevented.

16

17 The pin section connector at one end and box section connector at the other end of the
18 drill pipe member are configured to mate with a corresponding connector on an adjacent
19 drill pipe member to form a tool joint.

20

21 The upper drill string may be located within the substantially vertical section of the
22 wellbore, riser, casing and/or liner. The lower drill string well bore may be located within
23 the substantially non-vertical section of the wellbore, casing and/or liner.

24

25 The drill pipe members in the upper drill string may have a tool joints with diameters equal
26 to the outer diameter of the tubular body of the drill pipe. The tubular body outer diameter
27 may be flush or parallel with the outer diameter of the tool joints in the upper drill string.

28

29 The drill pipe members in the lower drill string may have a tubular body outer diameter less
30 than the outer diameter of the tool joints of drill pipe over its length. The outer diameter of
31 the drill pipe members in the lower drill string may have portions of enlarged diameter
32 adjacent each end of the pipe joint having a diameter equal to the diameter of the external
33 upset required for tool joints.

34

1 Embodiments of the sixth aspect of the invention may include one or more features of the
2 first to fifth aspects of the invention or their embodiments, or vice versa.

3

4 According to a seventh aspect of the invention, there is provided a managed pressure
5 drilling system for use in managed pressure drilling in a subsea well, the system
6 comprising:

7 a riser;

8 a rotating sealing device; and

9 a drill string comprising a plurality of drill pipe members;

10 wherein each drill pipe member comprises;

11 a tubular pipe body with connectors at either end thereof for connection to adjacent drill
12 pipe members;

13 wherein the connectors and the tubular pipe body of the drill pipe member in the drill string
14 have substantially the same outer diameter; and

15 the rotating sealing device is configured to form a fluid seal between at least part of the
16 drill string passing through the rotating sealing device and the riser.

17

18 The rotating sealing device may be configured to form a fluid seal between an outer
19 surface of the drill string passing through the rotating sealing device and an inner surface
20 of the riser.

21

22 The drill string may be an upper drill string section. The system may comprise a lower drill
23 string. The drill string may be connectable to a lower drill string connected to a drill bit.

24 The lower drill string may comprise plurality of drill pipe members; wherein each drill pipe
25 member in the lower drill string comprises a tubular pipe body with connectors at either
26 end thereof for connection to adjacent drill pipe members wherein the connectors of the
27 drill pipe members in the lower drill string have an outer diameter which is larger than the
28 outer diameter of the tubular pipe body of the drill pipe members in the lower drill string.

29

30 The larger diameter connectors in the lower drill string may provide structural support to
31 the connections between the drill pipe members in the lower drill string to provide flexibility
32 as the lower drill string deviates from the vertical in the wellbore. The larger diameter
33 connectors may also reduce or minimise mechanical or bending stresses acting on the
34 connections of the lower drill string as it curves and deviates from the vertical.

35

1 Embodiments of the seventh aspect of the invention may include one or more features of
2 the first to sixth aspects of the invention or their embodiments, or vice versa.

3

4 According to an eighth aspect of the invention, there is provided a managed pressure
5 drilling system for use in managed pressure drilling in an onshore well, the system
6 comprising:

7 an upper casing;

8 a rotating sealing device; and

9 a drill string comprising a plurality of drill pipe members;

10 wherein each drill pipe member comprises;

11 a tubular pipe body with connectors at either end thereof for connection to adjacent drill
12 pipe members;

13 wherein the connectors and the tubular pipe body of the drill pipe member in the drill string
14 have substantially the same outer diameter; and

15 the rotating sealing device is configured to form a fluid seal between at least part of the
16 drill string passing through the rotating sealing device and the upper casing.

17

18 The rotating sealing device may be configured to form a fluid seal between at least part of
19 an outer surface of the drill string passing through the rotating sealing device and an inner
20 surface of the upper casing.

21

22 The drill string may be an upper drill string section. The system may comprise a lower drill
23 string section. The drill string may be connectable to a lower drill string connected to a drill
24 bit. The lower drill string may comprise a plurality of drill pipe members; wherein each drill
25 pipe member in the lower drill string comprises a tubular pipe body with connectors at
26 either end thereof for connection to adjacent drill pipe members wherein the connectors of
27 the drill pipe members in the lower drill string have an outer diameter which is larger than
28 the outer diameter of the tubular pipe body of the drill pipe members in the lower drill
29 string.

30

31 The larger diameter connectors in the lower drill string may provide structural support to
32 the connections between the drill pipe members to provide flexibility as the lower drill string
33 deviates from the vertical in the wellbore. The larger diameter connectors may also reduce
34 or minimise mechanical or bending stresses acting on the connections of the lower drill
35 string as it curves and deviates from the vertical.

1 Embodiments of the eighth aspect of the invention may include one or more features of the
2 first to seventh aspects of the invention or their embodiments, or vice versa.

3

4 According to a ninth aspect of the invention, there is provided a method for managed
5 pressure drilling, comprising the steps of:

6 providing a managed pressure drilling system, the system comprising:

7 a rotating sealing device; and

8 a drill string comprising a plurality of drill pipe members;

9 wherein each drill pipe member comprises;

10 a tubular pipe body with connectors at either end thereof for connection to adjacent drill
11 pipe members;

12 wherein the connectors and the tubular pipe body of the drill pipe member in the drill string
13 have substantially the same outer diameter;

14 lowering the drill string into a tubular connected to a well;

15 forming a fluid seal between the drill string and the tubular;

16 passing at least a portion of the drill string through the rotating sealing device.

17

18 The method may comprise drilling the wellbore. The method may comprise drilling the
19 wellbore at a pre-determined fluid annular pressure. The predetermined fluid annular
20 pressure may be less than a casing shoe pressure and/or a formation fracture pressure.

21

22 The method may comprise forming a fluid seal between the drill string and the tubular by
23 contacting at least one sealing element in the rotating sealing device with an outer surface
24 of part of the drilling string.

25

26 The method may comprise connecting the drill string and/or one or more drill pipe
27 members to a lower drill string. The lower drill string may be configured to be connected to
28 or may be connected to a drill bit.

29

30 The drill string may be arranged into an upper drill string portion and a lower drill string
31 portion. The connectors and the tubular pipe body of the drill pipe member in the upper
32 drill string may have substantially the same outer diameter. The connectors and the
33 tubular pipe body of the drill pipe member in the upper drill string may have different outer
34 diameters.

35

1 The lower drill string may be connected to a bottom hole assembly. The lower drill string
2 may comprise a plurality of drill pipe members; wherein each drill pipe member in the
3 lower drill string comprises a tubular pipe body with connectors at either end thereof for
4 connection to adjacent drill pipe members wherein the connectors of the drill pipe
5 members in the lower drill string have an outer diameter which is larger than the outer
6 diameter of the tubular pipe body of the drill pipe members in the lower drill string.

7
8 The method may be used for onshore or offshore drilling. The tubular may be a riser,
9 casing and/or liner. The method may comprise deviating the lower drill string from the
10 vertical. The method may comprise maintaining the upper drill string substantially vertical.

11
12 The method may comprise locating and/or maintaining the drill string in a substantial
13 vertical section of the tubular and/or well. The method may comprise locating the lower drill
14 string in a substantial non-vertical section of the wellbore.

15
16 Embodiments of the ninth aspect of the invention may include one or more features of the
17 first to eighth aspects of the invention or their embodiments, or vice versa.

18
19 According to a tenth aspect of the invention, there is provided a method for managed
20 pressure drilling in a subsea well, comprising:
21 providing a managed pressure drilling system, the system comprising:
22 a riser;
23 a rotating sealing device;
24 a drill string comprising a plurality of drill pipe members arranged in a first drill string
25 section and a second drill string section;
26 wherein the drill pipe members of the second drill string section are flush joint drill pipe
27 members having an equal outer diameter along its length; and
28 wherein the drill pipe members of the first drill string section have tool joints at each end of
29 a tubular body which have an outer diameter greater than the tubular body outer diameter;
30 lowering the drill string into the riser;
31 forming a fluid seal between the riser and an outer surface of the second drill string
32 section; and
33 passing at least a portion of the section drill string through the rotating sealing device; and
34 drilling the wellbore.

35

1 The method may comprise drilling the wellbore at a pre-determined fluid annular pressure.

2 The method may comprise connecting a drill bit to the first drill string section.

3

4 The method may comprise locating and/or maintaining the second drill string section in a
5 substantial vertical section of the riser. The method may comprise locating the first drill
6 string section in a substantial non-vertical section of the wellbore.

7

8 Embodiments of the tenth aspect of the invention may include one or more features of the
9 first to ninth aspects of the invention or their embodiments, or vice versa.

10

11 According to an eleventh aspect of the invention, there is provided a method for managed
12 pressure drilling in a well, comprising:

13 providing a managed pressure drilling system, the system comprising:

14 an upper casing;

15 a rotating sealing device;

16 a drill string comprising a plurality of drill pipe members arranged in a first drill string
17 section and a second drill string section;

18 wherein the drill pipe members of the second drill string section are flush joint drill pipe
19 members having an equal outer diameter along its length; and

20 wherein the drill pipe members of the first drill string section have tool joints at each end of
21 a tubular body which have an outer diameter greater than the tubular body outer diameter;

22 lowering the drill string into the casing;

23 forming a fluid seal between the casing and an outer surface of the second drill string
24 section; and

25 passing at least a portion of the second drill string section through the rotating sealing
26 device; and

27 drilling the wellbore.

28

29 The method may comprise drilling the wellbore at a pre-determined fluid annular pressure.

30 The well may be an onshore or offshore well. The method may comprise locating and/or
31 maintaining the second drill string in a substantial vertical section of the casing, liner
32 and/or well. The method may comprise locating and/or maintaining the first drill string in a
33 substantial non-vertical section of the wellbore.

34

1 The first drill section may be a lower drill string section connected to a drill bit. The second
2 drill string section may be an upper drill string section.

3

4 Embodiments of the eleventh aspect of the invention may include one or more features of
5 the first to tenth aspects of the invention or their embodiments, or vice versa.

6

7 According to a twelfth aspect of the invention, there is provided a method for drilling a well,
8 comprising:

9 providing a drilling system, the system comprising:

10 a rotating sealing device; and

11 a drill string comprising a plurality of drill pipe members arranged in a first drill string
12 section;

13 wherein each drill pipe member comprises a tubular pipe body with connectors at either
14 end thereof for connection to adjacent drill pipe members;

15 drilling a first section of the well using the first drill string section comprising a plurality of
16 first drill pipe members with connectors larger than the outer diameter of the tubular pipe
17 body;

18 connecting a second drill string section to the first drill string section wherein the
19 connectors and the tubular pipe body of the plurality of drill pipe members in the second
20 drill string section have substantially the same outer diameter;

21 forming a fluid seal between a tubular connected in the well and a part of the outer surface
22 of the second drill string section; and

23 passing at least a portion of the second drill string through the rotating sealing device; and
24 drilling a second section of the well.

25

26 The method may comprise drilling a second section of the well at a pre-determined fluid
27 annular pressure. The method may comprise installing or connecting the tubular to the first
28 section of the well. The tubular may be a riser, casing and/or liner. The method may
29 comprise drilling the first section of the well using conventional well control drilling. The
30 method may comprise drilling the second section of the well by using managed pressure
31 drilling.

32

33 The method may comprise drilling a third section of the well by using conventional well
34 control drilling. The method may comprise drilling a third section of the well by connecting
35 a third drill string section to an upper portion of the second drill string section. The outer

1 diameter of the connectors of the drill pipe members in the third drill string section may be
2 larger or different than the outer diameter of the tubular pipe body of the drill pipe
3 members in the third drill string section. The method may comprise removing or
4 deactivating the seal and/or the rotating sealing device before drilling the third section of
5 the well.

6
7 The method may comprise drilling one or more further sections of the well using managed
8 pressure drilling by reforming or reactivating the seal and/or reinstalling the RCD and
9 connecting a further drill string section to the drill string wherein the connectors and the
10 tubular pipe body of the plurality of drill pipe members in the further drill string have
11 substantially the same outer diameter.. The method may comprise passing at least a
12 portion of the further drill string through the rotating sealing device; and drilling the further
13 section of the well at a pre-determined fluid annular pressure.

14
15 The method may comprise alternating between conventional drilling and managed
16 pressure drilling to drill further sections of the well. When managed pressure drilling is
17 required the uppermost section of drill string may comprise parallel drill pipe with a
18 continuous outer surface diameter along its longitudinal length of the drill string section to
19 allow an effective seal to be maintained with the RCD as the drill pipe is moved downhole
20 or raised uphole. The continuous outer surface diameter of the parallel drill string mitigates
21 wear on sealing elements in the RCD.

22
23 The method may comprise drilling at a deviated angle to the horizontal.

24
25 Embodiments of the twelfth aspect of the invention may include one or more features of
26 the first to eleventh aspects of the invention or their embodiments, or vice versa.

27
28 According to a thirteenth aspect of the invention, there is provided a method for raising or
29 lowering a drill string in well, comprising:
30 providing a drilling system, the system comprising:
31 a rotating sealing device; and
32 a drill string comprising a plurality of drill pipe members wherein each drill pipe member
33 has a first tool joint having a first tool joint outer diameter;
34 a second tool joint having a second tool joint outer diameter; and

1 a tubular body between the first and second tool joints having a tubular body outer
2 diameter;
3 wherein at least one section of the drill string has a first tool joint outer diameter, the
4 second tool joint outer diameter and the tubular body outer diameter are substantially the
5 same; and
6 wherein the rotating sealing device is configured to form a fluid seal against at least part of
7 the at least one section of the drill string;
8 lowering or raising the at least one section of the drill string in the well through the rotating
9 sealing device.

10

11 Embodiments of the thirteenth aspect of the invention may include one or more features of
12 the first to twelfth aspects of the invention or their embodiments, or vice versa.

13

14 According to a fourteenth aspect of the invention, there is provided a drill string assembly
15 for managed pressure drilling the drill string comprising:

16 a plurality of drill pipe members wherein each drill pipe members has a first tool joint
17 having a first tool joint outer diameter;

18 a second tool joint having a second tool joint outer diameter; and

19 a tubular body between the first and second tool joints having a tubular body outer
20 diameter;

21 wherein each drill pipe members in at least one section of the drill string has a first tool
22 joint outer diameter and a second tool joint outer diameter which are substantially equal to
23 the tubular body outer diameter wherein in at least one section of the drill string has a
24 substantially constant outer diameter along its length.

25

26 The at least one section of the drill string may be a section of the drill string located at a
27 uphole end of the drill string section. The at least one section of the drill string may be a
28 section of the drill string located closest to the surface or closest to the top of a riser.

29

30 The at least one section of the drill string may be a located above a lower section of drill
31 string. The lower section of drill string may be configured to be connected to or may be
32 connected to a drill bit. The at least one section of the drill string may be configured to
33 connected to the lower drill string.

34

1 The lower drill string may comprise a plurality of drill pipe members wherein each drill pipe
2 member has a first tool joint having a first tool joint outer diameter; a second tool joint
3 having a second tool joint outer diameter; and a tubular body between the first and
4 second tool joints having a tubular body outer diameter; wherein the first tool joint outer
5 diameter and the second tool joint outer diameter may be larger than or different to the
6 tubular body outer diameter.

7

8 Embodiments of the fourteenth aspect of the invention may include one or more features
9 of the first to thirteenth aspects of the invention or their embodiments, or vice versa.

10

11 According to a fifteenth aspect of the invention, there is provided a managed pressure
12 drilling system comprising:

13 a rotating sealing device; and

14 a drill string comprising a plurality of drill pipe members wherein each drill pipe member
15 has a first tool joint having a first tool joint outer diameter;

16 a second tool joint having a second tool joint outer diameter; and

17 a tubular body between the first and second tool joints having a tubular body outer
18 diameter;

19 wherein in at least one section of the drill string the first tool joint outer diameter, the
20 second tool joint outer diameter and the tubular body outer diameter are substantially the
21 same; and

22 wherein the rotating sealing device is configured to form a fluid seal against at least a part
23 of the at least one section of drill string.

24

25 The at least one section of the drill string may have an outer diameter that is substantially
26 uniform along its longitudinal length.

27

28 The drill string may be arranged into two or more sections wherein the at least one section
29 of the drill string having a first tool joint outer diameter, the second tool joint outer diameter
30 and tubular body outer diameter which may be substantially the same may be an upper
31 drill string section. The drill string may comprise a lower drill string section wherein the
32 first tool joint outer diameter and/or the second tool joint outer diameter may be larger than
33 or different to the tubular body outer diameter in each drill pipe member in the lower drill
34 string section.

35

1 Embodiments of the fifteenth aspect of the invention may include one or more features of
2 the first to fourteenth aspects of the invention or their embodiments, or vice versa.

3

4 According to a sixteenth aspect of the invention, there is provided a method for drilling a
5 well, the method comprising:

6 providing a drilling system, the system comprising:

7 a rotating sealing device; and

8 a plurality of drill pipe members comprising first drill pipe members and second drill pipe
9 members;

10 wherein each drill pipe member comprises a tubular pipe body with connector joints at
11 either end thereof;

12 wherein first drill pipe members have connector joint outer diameters which are larger than
13 the outer diameter of the tubular pipe body;

14 wherein second drill pipe members have connector joint outer diameters which are
15 substantially the same as the outer diameter of the tubular pipe body;

16 wherein the first drill pipe members are configured to be connected to form a first drill
17 string section and the second drill pipe members are configured to be connected to form a
18 second drill string section;

19 drilling a first section of the well using the first drill string section comprising a plurality of
20 first drill pipe members;

21 connecting second drill pipe members to the first drill string section;

22 forming a fluid seal between a tubular connected in the well and an outer surface of at
23 least part of a second drill pipe member in the second drill string section;

24 passing at least part of the second drill string through the rotating sealing device; and

25 drilling a second section of the well at a pre-determined fluid annular pressure.

26

27 The method may comprise drilling a first section of the well using conventional drilling and
28 drilling the second section of the well using managed pressure drilling. The method may
29 comprise drilling a third section of the well using conventional drilling or managed pressure
30 drilling.

31

32 The method may comprise drilling a third section of the well by connecting a plurality of
33 third drill pipe members to an upper portion of the second drill string section.

34

1 The third section of the well may be drilled using conventional drilling wherein the rotating
2 sealing device is removed or deactivated and the third drill pipe members in third drill
3 string section comprise connector joints which are larger than the outer diameter of the
4 tubular pipe body of the third drill pipe members in the third drill string section.

5
6 Embodiments of the sixteenth aspect of the invention may include one or more features of
7 the first to fifteenth aspects of the invention or their embodiments, or vice versa.

8
9
10 Brief description of the drawings

11
12 There will now be described, by way of example only, various embodiments of the
13 invention with reference to the drawings, of which:

14
15 Figure 1A is a sectional side view of a drill pipe assembly according to an embodiment of
16 the invention;

17
18 Figure 1B is an enlarged sectional side view of part of an upper drill string portion of the
19 drill pipe assembly of Figure 1A;

20
21 Figure 1C is an enlarged sectional side view of part of a lower drill string portion of the drill
22 pipe assembly of Figure 1A;

23
24 Figure 2 is a schematic representation of a managed pressure drilling system for offshore
25 managed pressure drilling in a deviated well according to an embodiment of the invention
26 with the managed pressure drilling components omitted for clarity;

27
28 Figure 3 is a schematic representation of a managed pressure drilling system for onshore
29 managed pressure drilling in a deviated well according to an embodiment of the invention
30 with the managed pressure drilling components omitted for clarity; and

31
32 Figures 4A, 4B and 4C are schematic representations of stages of drilling a deviated well
33 using conventional and managed pressure drilling operations according to an embodiment
34 of the invention.

35

1 Detailed description of preferred embodiments

2

3 Referring firstly to Figures 1A, 1B and 1C there is represented a drill string apparatus for
4 managed pressure drilling generally depicted at 10. The drill string apparatus 10
5 comprises an upper drill string portion 12 and a lower drill string portion 14. The upper drill
6 string portion 12 comprises a plurality of drill pipe members 12a that are connected in an
7 end-to-end relationship. The lower drill string portion 14 comprises a plurality of drill pipe
8 members 14a that are connected in an end-to-end relationship.

9

10 In use the lower drill string portion 14 is located closest to the bottom hole assembly drill
11 bit (not shown). The upper drill string portion 12 is positioned closest to the surface so that
12 it engages a rotary seal member discussed further in Figures 2, 3 and 4A to 4C below.

13

14 As best shown in Figures 1A and 1B, each of the drill pipe members 12a in the upper drill
15 string portion 12 has a tubular central body 13 with tool joints 13a at each end. The tool
16 joints are connectors also known as connector joints which connect the drill pipe members
17 to one another. In this example the tool joints 13a are a box section 16 at a first end of the
18 tubular body and a pin section 18 at a second end of the tubular body 13. The box section
19 16 is designed to connect to a pin section 18 of an adjacent drill pipe member such as by
20 threadedly coupling. Similarly, the pin section 18 is designed to connect to the box section
21 of an adjacent drill pipe member. The tool joints 13a and the tubular pipe body 13 of the
22 upper drill pipe members 12 have substantially the same outer diameter (OD). The tool
23 joints 13a are flush with the tubular central body 13 of the drill pipe members 12a in the
24 upper drill string portion 12.

25

26 As best shown in Figures 1A and 1C, each of the drill pipe members 14a in the lower drill
27 string portion 14 has a tubular central body 15 with tool joints 15a at each end. In this
28 example the tool joints 15a are a box section 20 at a first end of the tubular central body
29 and a pin section 22 at a second end of the tubular central body 15. The box section 20 is
30 designed to threadedly couple to the pin section of an adjacent drill pipe member to form a
31 drill string. Similarly, the pin section 22 is designed to threadedly couple to the box section
32 20 of an adjacent drill pipe member.

33

34 The box section 20 has an external upset 20a formed as a radially flared extension of the
35 body section 15. The upset 20a provides structural support to the box section 20 when

1 threaded coupled to a pin section 22 of an adjacent drill pipe member. Similarly, the pin
2 section 22 has an external upset 22a formed as a radially flared extension of the body
3 section 15 which provides structural support to the box section 22 when threaded coupled
4 to a box section 20 of an adjacent drill pipe member 14a.

5
6 The outer diameter of the tool joints 15a and upsets 20a, 22a is larger than the outer
7 diameter of the tubular central pipe body 15 of the lower drill pipe members 14a.

8
9 As shown in Figure 1A, a pin section 18 of the upper drill string 12 connects to a box
10 section 20 of the lower drill string to connect the upper and lower drill strings.
11 However, it will be appreciated that the pin and box section arrangements may be
12 reversed and a box section of the upper drill string may be connected to a pin section of
13 the lower drill sting.

14
15 Although in the above examples the connectors (tool joints) which couple the drill pipe
16 members are pin and box type connectors, it will be appreciated that other connection
17 types may be used.

18
19 It will be appreciated that the tool joint 13a of the upper drill string portion may have
20 internal upsets to provide structural support to the connectors between the drill pipe
21 members 12a without affecting the flush outer diameter.

22
23 Figure 2 shows an offshore managed pressure drilling system 100 comprising the drill pipe
24 assembly 10. The system 100 comprises a marine riser 130 suspended from a floating
25 drilling vessel 132. The drilling vessel is positioned at the surface 134 of a body of water
26 136 above a subsea wellhead 138 located on the seabed 140. The vessel 132 will
27 normally be equipped with a derrick, rotary table and other conventional drilling equipment
28 (not shown).

29
30 The riser 130 extends from the vessel 132, through the body of water 136, and connects to
31 the wellhead 138. The riser 130 forms a conduit between the vessel 132 and the wellhead
32 138. The marine riser 130 is configured for conveying the drill pipe assembly 10 and
33 drilling fluids. Riser equipment and components such as auxiliary lines, kill and choke lines
34 are not shown for clarity. The riser allows return of the drilling mud with drill cuttings from
35 the hole that is being drilled and acts as a guide for the upper drill string portion 12.

1 A rotating control device (RCD) 150 is connected to the riser at an upper end of the riser
2 130, such as by a flanged connection. The RCD is configured to seal against drill pipe
3 members 12a in the upper drill string portion 12 to create a pressure-tight barrier.

4
5 As shown in the Figure 2, the upper drill string portion 12 is located in the generally vertical
6 riser and the lower drill string portion 14 is located in the wellbore below or adjacent to the
7 wellhead.

8
9 The RCD 150 comprises at least one elastomeric sealing element 152 which rotates as
10 the drill pipe member 12a rotates and is flexible enough to accommodate and allow the
11 flush drill pipe members in the upper drill string portion 12 to pass through the sealing
12 element 152 without damaging the sealing element. The at least one elastomeric sealing
13 element 152 in the RCD maintains a tight seal with drill pipe members 12a in the upper
14 drill string portion such that returning fluids in the annulus are contained in the riser 130
15 below the RCD 150 as the flush drill pipe members 12a in the upper drill string portion
16 pass through the RCD in a downhole or uphole direction.

17
18 By maintaining an effective seal with the drill pipe members 12a any flow of fluid between
19 the at least one sealing element 152 and the drill pipe members 12a is substantially
20 prevented.

21
22 During a subsea drilling operation as the drill bit 142 penetrates deeper into the earth, the
23 flush upper drill string 12 is vertically lowered (arrow "A") or raised (arrow "B") in the riser
24 and passes through the rotating control device.

25
26 As the upper drill string portion 12 has the same outer diameter throughout its length "L"
27 an effective seal can be maintained between the outer surface of the drill pipe members
28 12a in the upper drill string portion 12 and the sealing elements 150. As the tool joints 13a
29 in each drill pipe member 12a in the upper drill string portion 12 are flush with the main
30 tubular body 13 in the upper drill string portion the upper drill string portion 12 can pass
31 through the RCD 150 without resulting in friction, drag or wear on the at least one sealing
32 element 152.

33
34 As the bottom hole assembly 144 including drill bit 142 drills deeper and deviates from the
35 vertical as shown in Figure 2, the lower drill string 14 follows an angled or curved path that

1 deviates anywhere from a few degrees off the vertical axis to a substantially horizontal
2 axis.

3
4 Each of the drill pipe members 14a in the lower drill string portion 14 has tool joints 15a
5 which have external upsets 20a, 22a. The external upsets 20a, 22a have an outer
6 diameter larger than the main tubular body 15 of the drill members in the lower drill string
7 portion. The larger diameter external upsets 20a, 22a provide the tool joints 15a at the
8 ends of the drill pipe members 14a with an increased thickness which provides a larger
9 and stronger connection between the drill pipe members 14a. This may mitigate
10 mechanical stresses acting on the lower drill string portion 14 preventing fatigue failure as
11 the lower drill string portion 14 deviates from the vertical during drilling in deviated or
12 horizontal wells.

13
14 The external upsets 20a, 22a of the tool joints 15a may distance the main tubular body 15
15 of the drill pipe members 14a from the wellbore 146 and protect the main tubular body 15
16 from contact with the wellbore 146. This may prevent wear and damage of the main
17 tubular body. Furthermore by providing upsets 20a, 22a which distance the main tubular
18 body 15 from the well bore 146, frictional and torsional forces which may resist the rotation
19 of the drill string during drilling may be mitigated.

20
21 Figure 3 shows an onshore managed pressure drilling system 200 which uses the drill pipe
22 assembly 10. The system 200 is similar to the operation of the system 100 described
23 above in relation to Figure 2. The onshore managed pressure drilling system 200 will be
24 understood from Figure 2 and its description above. However the system 200 is onshore
25 and uses a casing 245 in the well 246 to contain the upper drill string portion instead of
26 marine riser.

27
28 A riser is therefore not required in system 200, instead a casing 245 in the wellbore 246
29 contains the upper drill string section or portion 12 instead of marine riser. An RCD 250 is
30 connected to the casing and is configured to seal against drill pipe members 12a in the
31 upper drill string section or portion 12 to create a pressure-tight barrier.

32
33 As the upper drill string portion 12 has the same outer diameter throughout its length "L"
34 an effective seal can be maintained between the outer surface of the drill pipe members
35 12a in the upper drill string portion 12 and the sealing elements 252 of the RCD 250. As

1 the tool joints 13a in each drill pipe member 12a in the upper drill string portion 12 are
2 flush with the main tubular body 13 in the upper drill string portion the upper drill string
3 portion 12 can pass through the RCD 250 without resulting in friction, drag or wear on the
4 at least on rotating sealing element 252.

5

6 As the bottom hole assembly 244 including drill bit 242 drills deeper and deviates from the
7 vertical as shown in Figure 3, the lower drill string 14 follows an angled or curved path that
8 deviates anywhere from a few degrees off the vertical axis to a substantially horizontal
9 axis.

10

11 Each of the drill pipe members 14a in the lower drill string portion 14 has tool joints 15a
12 which have external upsets 20a, 22a. The external upsets 20a, 22a have an outer
13 diameter larger than the main tubular body 15 of the drill members in the lower drill string
14 portion. The larger diameter external upsets 20a, 22a provide the tool joints 15a at the
15 ends of the drill pipe members 14a with an increased thickness which provides a larger,
16 stronger and stiffer connection between the drill pipe members 14a. This mitigates
17 mechanical stresses acting on the lower drill string portion 14 preventing fatigue failure as
18 the lower drill string portion 14 deviates from the vertical during drilling in deviated or
19 horizontal wells.

20

21 The external upsets 20a, 22a of the tool joints 15a distance the main tubular body 15 of
22 the drill pipe members 14a from the wellbore 246 and protects the main tubular body 15
23 from contact with the wellbore 246. This prevents wear and damage of the main tubular
24 body. Furthermore by providing upsets 20a, 22a which distance the main tubular body 15
25 from the well bore 246, frictional and torsional forces which may resist the rotation of the
26 drill string during drilling are mitigated.

27

28 Figures 4A, 4B and 4C show stages of drilling an offshore well. The system 300 comprises
29 a marine riser 330 suspended from a floating drilling vessel 332. The drilling vessel is
30 positioned at the surface 334 of a body of water 336 above a subsea wellhead 338 located
31 on the seabed 340.

32

33 The vessel 332 will normally be equipped with a derrick, rotary table and other
34 conventional drilling equipment (not shown).

35

1 The riser 330 extends from the vessel 332, through the body of water 336, and connects to
2 the wellhead 338. The riser 330 forms a conduit between the vessel 332 and the wellhead
3 338. The marine riser 330 is configured for conveying the drill pipe assembly 310 and
4 drilling fluids. Riser equipment and components such as auxiliary lines, kill and choke lines
5 are not shown for clarity. The riser 330 allows return of the drilling mud with drill cuttings
6 from the hole that is being drilled and acts as a guide for the drill string 310.

7
8 Figure 4A shows the conventional drilling of a first section of a well. A first section of drill
9 string 310 is lowered into the riser. In this example the first drill string section is made of
10 conventional drill pipe members. Each of the drill pipe members 314a in the first drill string
11 section 314 has tool joints 315a which have external upsets 320a, 322a. The external
12 upsets 320a, 322a have an outer diameter larger than the main tubular body 315 of the
13 drill members in the first drill string section.

14
15 The larger diameter external upsets 320a, 322a provide the tool joints 315a at the ends of
16 the drill pipe members 314a with an increased thickness which provides a larger and
17 stronger connection between the drill pipe members 314a. This mitigates mechanical
18 stresses acting on the first drill string portion 314 preventing fatigue failure as the first drill
19 string portion 314 deviates from the vertical during drilling in deviated or horizontal wells.

20
21 The conventional drilling method use drilling fluids open to atmospheric pressure to create
22 an equivalent circulating density (ECD) that results in a bottom hole pressure (BHP)
23 greater than pore pressure but less than the fracture initiation pressure of the formation
24 being penetrated.

25
26 When the well reservoir pore pressure and the fracture pressure is reduced to a narrow
27 window it is necessary to continue drilling using Managed pressure drilling (MPD) as
28 shown in Figure 4B, to maintain a downhole pressure that prevents the flow of formation
29 fluids into the wellbore while keeping pressure well below the fracture initiation pressure.

30
31 In order to perform managed pressure drilling the annulus between the drill string and the
32 riser is sealed by a rotating control device (RCD) 350. A drill pipe member 312a with flush
33 tool joints 313a is connected to the first section (lower) of the drill sting 314. Further drill
34 pipe member 312a with flush tool joints 313a are connected end to end to form a second
35 drill sting section 312.

1 Each of the drill pipe members 312a in the second (upper) drill string section 312 has a
2 tubular central body 313 with tool joints 313a at each end. In this example the tool joints
3 313a are a box section 316 at a first end of the tubular body and a pin section 318 at a
4 second end of the tubular body 313. The box section 316 is designed to connect to a pin
5 section 318 of an adjacent drill pipe member. Similarly, the pin section 318 is designed to
6 connect to the box section of an adjacent drill pipe member.

7
8 The tool joints 313a and the tubular pipe body of the drill pipe members 312a in the
9 second drill string section 312 have substantially the same outer diameter (OD). The tool
10 joints 313a are flush with the tubular central body 313 of the drill pipe members 312a in the
11 second drill string portion 312. The box section 316 and pin section 318 have internal
12 upsets to provide strength to the tool joints 313a.

13
14 The RCD 350 is connected to the riser 330 at an upper end of the riser, such as by a
15 flanged connection. The RCD is configured to seal against at least a part of a drill pipe
16 member 312a in the second drill string section 312 to create a pressure-tight barrier.

17
18 The RCD 350 comprises a least one elastomeric sealing element 352 which rotates as the
19 drill pipe member 312a rotates and is flexible enough to accommodate and allow the flush
20 drill pipe members in the second drill string portion 312 to pass through the sealing
21 element 352 without damaging the at least one sealing element 352. The at least one
22 elastomeric sealing element 352 in the RCD maintains a tight seal with drill pipe members
23 312a in the second string section or portion such that returning fluids in the annulus are
24 contained in the riser 330 below the RCD 350 as the flush drill pipe members 312a in the
25 second drill string section or portion pass through the RCD.

26
27 As the second drill string section or portion 312 has the same outer diameter throughout its
28 length "L" an effective seal can be maintained between an outer surface of the drill pipe
29 members 312a in the second drill string portion 312 and the sealing elements 350. As the
30 tool joints 313a in each drill pipe member 312a in the second drill string portion 312 are
31 flush with the main tubular body 313 in the upper drill string portion the second string
32 portion 312 can pass through the RCD 350 without resulting in friction, drag or wear on the
33 at least on rotating sealing element 352.

34

1 Each of the drill pipe members 314a in the first drill string portion 314 has tool joints 315a
2 which have external upsets 320a, 322a. The external upsets 320a, 322a have an outer
3 diameter larger than the main tubular body 315 of the drill members in the first drill string
4 portion. The larger diameter external upsets 320a, 322a provide the tool joints 315a at the
5 ends of the drill pipe members 314a with an increased thickness which provides a larger
6 and stronger connection between the drill pipe members 314a. This mitigates mechanical
7 stresses acting on the first drill string portion 314 preventing fatigue failure as the first drill
8 string portion 314 deviates from the vertical during drilling in deviated or horizontal wells.

9
10 The external upsets 320a, 322a of the tool joints 315a distance the main tubular body 315
11 of the drill pipe members 314a from the wellbore 346 and protects the main tubular body
12 350 from contact with the wellbore 346. This prevents wear and damage of the main
13 tubular body. Furthermore by providing upsets 320a, 322a which distance the main tubular
14 body 315 from the well bore 346, frictional and torsional forces which may resist the
15 rotation of the drill string during drilling are mitigated.

16
17 Once MPD is no longer required, drilling may optionally be switched back to conventional
18 well control drilling as shown in Figure 4C by removing or deactivating the RCD 350. When
19 managed pressure drilling operations are not required the RCD may be removed by
20 decoupling and/or unlatching from the riser or deactivated such that no seal is formed with
21 the drill string. As there is no longer a requirement to seal the annulus between the drill
22 string and the riser, conventional drill pipe members 370a may be connected above the
23 second drill string section 312 to form a third string section 370.

24
25 Each of the drill pipe members 370a in the third drill string 370 has tool joints 355a which
26 have external upsets 360a, 362a. The external upsets 360a, 362a have an outer diameter
27 larger than the main tubular body 365 of the drill members 370a in the drill string.

28
29 As the drill bit 342 penetrates deeper into the earth, further drill pipe members 370a are
30 added to the third drill string 370 and the first and second drill string sections 312, 314
31 move further downhole in general direction shown as arrow "C".

32
33 As the bottom hole assembly 344 including drill bit 342 drills deeper and deviates from the
34 vertical as shown in Figure 4C, the first drill string section 314 follows an angled or curved
35 path that deviates anywhere from a few degrees off the vertical axis to a substantially

1 horizontal axis. However, the second drill string section 312 remains located in the
2 generally vertical riser and vertical section of the well.

3

4 The third drill string section 370 may be made of the same drill pipe members 314a as the
5 first drill string 314 with external upsets. The external upsets may assist in providing weight
6 on bit.

7

8 Optionally, in the event that further managed pressure drilling is required, the RCD is
9 reinstalled or reactivated and a fourth drill string section made of drill pipe members with
10 flush tool joints, similar to second drill string section which are added to the drill string
11 above the third drill section 370. A benefit of an embodiment of the invention is that the
12 RCD may be quickly and easily installed on the riser only when managed pressure drilling
13 is required.

14

15 Drill pipe members with flush tool joints connected together to form a parallel pipe drill
16 string may be used for just managed pressure drilling sections of the well in order to
17 ensure an effective seal with the RCD as the flush joint drill string 312 is vertically lowered
18 or raised in the riser 330 and passes through the rotating control device.

19

20 Alternatively after the managed pressure drilling well control is switched to conventional
21 well the second drill string 312 (parallel pipe drill string) may be extended rather than
22 providing a third drill string section 370 (conventional pipe drill string). In this case further
23 drill pipe members 312a are added to the second drill string section 312.

24

25 Throughout the specification, unless the context demands otherwise, the terms 'comprise'
26 or 'include', or variations such as 'comprises' or 'comprising', 'includes' or 'including' will be
27 understood to imply the inclusion of a stated integer or group of integers, but not the
28 exclusion of any other integer or group of integers.

29

30 Furthermore, relative terms such as "lower", "upper", "up", "down", "above", "below",
31 "uphole", "downhole" and the like are used herein to indicate directions and locations as
32 they apply to the appended drawings and will not be construed as limiting the invention
33 and features thereof to particular arrangements or orientations. It will be appreciated that
34 the terms "portion" and "section" are interchangeable.

35

1 One advantage of an exemplary drill pipe apparatus described herein is the ability to apply
2 and maintain an effective seal against the drill pipe while providing a flexible drill string
3 which yields a greater rate of penetration in deviated and horizontal wells.

4

5 It will be appreciated that the drill pipe members in the second (upper) drill pipe section or
6 portion may have internal upsets to provide strength to the joints between drill pipe
7 members in the second (upper) drill pipe section or portion.

8

9 In the above examples the drill pipe members in the first (lower) drill pipe section or portion
10 are described as having external upsets. It will be appreciated that the drill pipe members
11 in the first (lower) drill pipe section or portion may alternatively have internal upsets.

12

13 The invention provides a managed pressure drilling system for use in managed pressure
14 drilling operations. The system comprises a rotating sealing device and
15 a drill string comprising a plurality of drill pipe members arranged in a first drill string
16 section and a second drill string section. Each drill pipe members comprises a first tool
17 joint having a first tool joint outer diameter, a second tool joint having a second tool joint
18 outer diameter and a tubular body between the first and second tool joints having a tubular
19 body outer diameter. The first tool joint outer diameter and second tool joint outer diameter
20 are larger than the tubular body outer diameter in each the drill pipe members in the first
21 drill string portion and first tool joint outer diameter and the second tool joint outer diameter
22 are substantially the same as the tubular body outer diameter in each drill pipe members in
23 the second drill string section The rotating sealing device is configured to form a fluid seal
24 against an outer surface of the second drill string section.

25

26 By providing a first or lower drill string section with each drill pipe members having
27 protruding tool joints with optional reinforcing external upsets and a second or upper drill
28 string section having drill pipe members with tool joints which are flush with the main
29 tubular body, the invention facilitates the drilling of wells that deviate from the vertical while
30 maintaining an effective seal around at least a part of the second or upper drill string
31 section.

32

33 Providing a flush or parallel drill string section enables the RCD to create a sealing barrier
34 with an outer surface of at least a part of the drill sting section including sections or parts of

1 the drill pipe members where there are flush tool joints. By providing flush tool joints in the
2 second or upper drill string section the RCD is not hindered by protruding tool joints.

3

4 The flush or parallel drill string section may also pass through the RCD during drill
5 operations without damaging or causing excessive wear on the sealing elements of the
6 RCD. A lower portion or section of the flush or parallel drill string may be connected to a
7 non-flush or non-parallel lower drill string section with external tool joint upsets. The
8 external tool joint upsets on the lower drill string section may reinforce the connection
9 between the drill pipe members reducing and/or minimising stresses on the tool joints as
10 the lower drill string portion curves or deviates from the vertical.

11

12 The foregoing description of the invention has been presented for the purposes of
13 illustration and description and is not intended to be exhaustive or to limit the invention to
14 the precise form disclosed. The described embodiments were chosen and described in
15 order to best explain the principles of the invention and its practical application to thereby
16 enable others skilled in the art to best utilise the invention in various embodiments and
17 with various modifications as are suited to the particular use contemplated. Therefore,
18 further modifications or improvements may be incorporated without departing from the
19 scope of the invention herein intended.

20

21

22

23