

Interim Directive ID 97-6

Note: Section 3 of this Interim Directive was rescinded by Guide 71 as released in June 2003.

Note: Directive 036 released in June 2004 incorporated some of the requirements specified here, particularly in parts of Section 4. The changes to this ID are detailed in Appendix 2 of Bulletin 2004-18. The page that documents these changes has been extracted from Bulletin 2004-18 and, for your convenience, has been appended at the end of this Interim Directive

13 February 1998

TO: All Operators and Drilling Contractors

SOUR WELL LICENSING AND DRILLING REQUIREMENTS

This directive updates and replaces the requirements of Interim Directive ID 87-2. Specifically, Sections 1, 2, 3, 4 and 7 are amended as herein described. Section 5, "Minimum Setbacks Separating Proposed Sour Wells from Residential and Other Developments" and Section 6, "Sour Well Emergency Response Plans" are replaced by Sections 2 and 3 of this directive. However, new emergency response planning requirements are expected to be announced following the completion of review work by a joint industry/Board stakeholder committee. Minimum setback requirements for all sour facilities, including wells, will be published in one document in the near future replacing Section 2 of this directive.

The requirements in this directive are in addition to those set out in the Oil and Gas Conservation Act, the Oil and Gas Conservation Regulations, and Guide 56 - Energy Development Application Guide and Schedules. The changes in this directive resulted from the integration of the well licensing process with the new energy development application process. The technical requirements for drilling a sour or critical sour well have remained largely unchanged.

This interim directive also supersedes IL 88-9.

Applicants requiring further information regarding this directive should contact the Board's Operations Group at 297-6952.

[Original signed by]

J. D. Dilay, P.Eng.
Board Member

Attachments

**ATTACHMENT TO INTERIM DIRECTIVE ID 97-6
SOUR WELL LICENSING AND DRILLING REQUIREMENTS**

CONTENTS	PAGE
1 SOUR WELL REQUIREMENTS	
1.1 Sour Wells	1 - 2
1.1.1 Application	1
1.1.2 Suspended/Producing H ₂ S Release Rate	1
1.1.3 Audit	2
1.2 Critical Sour Wells	2 - 3
1.2.1 Definition	2
1.2.2 Application	2
1.2.3 Receipt of Licence	2 - 3
1.2.4 Audit	3
1.2.5 Change from Critical to Non-critical Status	3
2 MINIMUM DISTANCE REQUIREMENTS SEPARATING PROPOSED SOUR WELLS FROM RESIDENTIAL AND OTHER DEVELOPMENTS	4 - 5
3 SOUR WELL EMERGENCY RESPONSE PLANS	
3.1 When a Plan is Required	6
3.2 Selection of Emergency Planning Zone	6 - 7
3.3 Emergency Plan Contents	7 - 8
3.4 Specific Requirements	8 - 9
4 DRILLING REQUIREMENTS AT CRITICAL SOUR WELLS	
4.1 Planning	10 - 11
4.2 Well Design	11 - 12
4.3 Equipment	
4.3.1 BOP Stack	12 - 14
4.3.2 BOP Manifold	15
4.3.3 Mud-Gas Separators	16 - 17
4.3.4 Drill Pipe	17
4.3.5 Drill String Valves	18
4.3.6 Monitoring Equipment	18 - 19
4.4 Practices	
4.4.1 Tripping	19
4.4.2 Testing and Coring	19 - 20
4.4.3 Underbalanced Drilling	20
4.5 Personnel	
4.5.1 Supervision	20
4.5.2 Rig Crew	20
4.5.3 Service Personnel	20

	4.5.4 Safety Specialists and Equipment	21
	4.6 Inspection	21
	4.7 Blowout Insurance	21-22
5	ENFORCEMENT	23

TABLES AND FIGURES

Figures

	ALTERNATIVE BOP STACK CONFIGURATIONS - CRITICAL SOUR WELLS	14
	MANIFOLD LAYOUT CRITICAL SOUR WELLS	15

Tables

Table 2.1	SUMMARY OF MINIMUM DISTANCE REQUIREMENTS SEPARATING PROPOSED SOUR WELLS FROM RESIDENTIAL AND OTHER DEVELOPMENTS	5
Table 4.1	ATMOSPHERIC, OPEN BOTTOM, MUD-GAS SEPARATOR VESSEL AND VENT LINE DIAMETER REQUIREMENTS FOR CRITICAL SOUR WELL DRILLING	16

APPENDICES

1	Definitions	24 - 26
2	References	27 - 28

1 SOUR WELL REQUIREMENTS

1.1 Sour Wells

1.1.1 Drilling Release Rate Application (Schedule 4-Guide 56)

The Board requires companies to evaluate the potential hydrogen sulphide (H₂S) release rate of every well which will penetrate formations that may contain H₂S and to plan for safe drilling operations consistent with potential occurrences. Each application for a well licence must include the results of that evaluation. Specifically, for any well which meets the sour well criteria in Guide 56, the applicant must complete the sour well section of the application and must include the following details: maximum H₂S content; calculated cumulative release rate during drilling operations; distance to nearest occupied dwelling; distance to nearest urban centre; number of occupied dwellings; public facilities and/or places of business within the planning zone¹; and size of calculated emergency planning zone radius. The applicant must retain documentation supporting the H₂S release rate determination including all relevant details used in the assessment. These must include, for each formation to be penetrated which may contain H₂S:

- (1) the maximum concentration of H₂S that can be expected and the source of that information,
- (2) the maximum surface deliverability that can be expected against zero back pressure for casing or open-hole flow configuration, and
- (3) the methodology used to determine the above.

1.1.2 Suspended/Producing H₂S Release Rate

The maximum potential H₂S release rate is used to determine the level classification and appropriate separation distance requirements of the well (Section 2). Where stimulation is normal or expected, a post-stimulation rate must be used.

Where the classification changes from non-critical to critical (for example after stimulation), the operator is responsible for meeting all critical well requirements in the post-drilling phase.

The Canadian Association of Petroleum Producers (CAPP) has recently established a task force

¹ If this number is greater than zero, or if the well is declared "critical," an emergency response plan will be required.

to study the methodology used in the calculation of potential H₂S release rates in order to provide guidelines for standard and consistent format for the proper retention of data. The guidelines are expected to be available in early 1998.

1.1.3 Audit

After receipt of a licence for any sour well, the requirements in this directive are subject to audit as part of the application audit system. In addition, an EUB representative may inspect any operation at a sour well .

1.2 Critical Sour Wells (Step 11 of Schedule 4-Guide 56)

1.2.1 Definition

A critical sour well includes any well from which the maximum potential H₂S release rate is:

- (1) 0.01 cubic metres per second (m³/s) or greater and less than 0.1 m³/s and which is located within 500 metres (m) of the corporate boundaries of an urban centre, or
- (2) 0.1 m³/s or greater and less than 0.3 m³/s and which is located within 1.5 km of the corporate boundaries of an urban centre, or
- (3) 0.3 m³/s or greater and less than 2.0 m³/s and which is located within 5 km of the corporate boundaries of an urban centre, or
- (4) 2.0 m³/s or greater.

1.2.2 Application

When applying for a well licence, the applicant must complete the appropriate section to indicate if the well is a critical sour well. If the applicant does not intend to follow a significant requirement in this directive or recommended practice within the Alberta Recommended Practices (ARPs) (e.g. exemption from setting intermediate casing), the applicant must indicate that it is filing a non-routine application by using a "No" response in Step 11 of Schedule 4, Guide 56.

1.2.3 Following Receipt of Licence

Within five (5) business days of receiving a well licence for the critical sour well, the licensee must notify in writing² the following, located in Edmonton:

Alberta Economic Development and Tourism, Corporate Communications
Alberta Health, Emergency Health Services

² The notification must include the date of the well licence and the surface location of the proposed well.

Alberta Transportation and Utilities, Disaster Services
Alberta Environmental Protection, Environmental Assessment Division and
Land Administration Division
RCMP

In addition, the licensee must file one copy of the critical well drilling plan with the appropriate Board Field Centre, also within five (5) business days of receiving the well licence.

1.2.4 Audit

The Board will audit all critical sour well licence applications immediately upon issuance of the well licence. A Board representative may inspect any operations at a critical sour well at any time.

1.2.5 Change from Critical to Non-critical Status

Once the Board or the applicant has determined a well to be critical, the well is subject to all critical well requirements at the drilling, completion, workover, and production phases of the well. In order to change the classification of the well, the licensee must notify the Board's Operations Group of the change in writing. This notification will be subject to audit and the Board will require the licensee to provide the most recent test information available, including the test interpretation, and the distance to the nearest dwelling and urban centre. The licensee is responsible to prove at any stage of the well (completion, workover, production), that the classification has been changed to non-critical and that critical well requirements are no longer applicable. The licensee must provide a copy of the notification and supporting information during a service rig or production inspection by Board field personnel.

2 MINIMUM DISTANCE REQUIREMENTS SEPARATING PROPOSED SOUR WELLS FROM RESIDENTIAL AND OTHER DEVELOPMENTS

In order to select appropriate well locations having regard for both public safety and present and future land use, the Board has established the following level classifications for sour wells. Each classification level has corresponding minimum separation distances between sour wells and residential and/or other developments. The distances increase as the suspended/producing H₂S release rate potential increases, and with increasing population density. Table 2.1 summarizes the separation distances for sour wells.

- (a) **Level 1 sour well:** Any well with a maximum potential H₂S release rate of 0.01 m³/s or greater and less than 0.3 m³/s. All wells remain subject to section 2.110 of the Oil and Gas Conservation Regulations which require a 0.1-km separation distance between each well and any surface improvement. The Board may specify some other separation distance for a Level 1 sour well should the circumstances warrant such action.
- (b) **Level 2 sour well:** Any well with a maximum potential H₂S release rate of 0.3 m³/s or greater and less than 2.0 m³/s. A Level 2 sour well shall be located to provide 0.1-km separation distance between it and any dwelling, and 0.5-km separation distance between it and any public facility or corporate boundary of an urban centre.
- (c) **Level 3 sour well:** Any well with a maximum potential H₂S release rate of 2.0 m³/s or greater and less than 6.0 m³/s. A Level 3 sour well shall be located to provide 0.1-km separation distance between it and any dwelling, 0.5-km separation distance between it and any unrestricted country development, and 1.5-km separation distance between it and any public facility or corporate boundary of an urban centre.
- (d) **Level 4 sour well:** Any well with a maximum potential H₂S release rate of 6.0 m³/s or greater. A Level 4 sour well shall be so located that as a minimum, it meets the requirements set out for a Level 3 sour well. However, the Board may require greater separation distances or set out other such requirements as it deems necessary.

With regard to encroachment of proposed surface development on existing sour wells, the subdivision and development regulation pursuant to the Municipal Government Act requires identical separation distances to be maintained.

TABLE 2.1 SUMMARY OF MINIMUM DISTANCE REQUIREMENTS SEPARATING PROPOSED SOUR WELLS FROM RESIDENTIAL AND OTHER DEVELOPMENTS

LEVEL CLASSIFICATION	PRODUCING/SUSPENDED H ₂ S RELEASE RATE m ³ /s	MINIMUM DISTANCE FROM PROPOSED WELL TO VARIOUS DEVELOPMENTS
1	\$ 0.01 - <0.3	0.1 km as stated in section 2.110 of the Oil and Gas Conservation Regulations
2	\$ 0.3 - <2.0	0.1 km to any dwelling 0.5 km to any urban centre or public facility
3	\$ 2.0 - <6.0	0.1 km to any dwelling 0.5 km to an unrestricted country development 1.5 km to an urban centre or public facility
4	\$ 6.0	As specified by the Board but not less than Level 3

NOTE: Any well classified as a Level 1, 2, 3, or 4 sour well may also be classified as a critical sour well (Section 4).

The 0.1 km separation distance to any dwelling is an absolute **minimum** distance and the Board would expect that the actual separation distance for any high H₂S release rate wells (particularly for Levels 3 and 4) will be at least 3 to 4 times the minimum distance. The Board would approve a setback closer to the prescribed minimum only if it is satisfied there is minimal risk associated with the proposed well and provided that the landowner and occupant of the dwelling are in agreement.

Note: Section 3 of this Interim Directive was superseded and rescinded by the June 2003 release of Guide 71 (now Directive 071)

6

3 SOUR WELL EMERGENCY RESPONSE PLANS

New emergency response planning requirements are expected to be released in early 1998. The Board anticipates that these requirements will be centred on emergency response planning guidelines being prepared by CAPP, and issued by the Board. These will replace the existing CPA/IPAC guidelines. In the interim, the licensee must file emergency response plans for review by the Board's Operations Group prior to the commencement of drilling operations.

The Board believes that operators must ensure public safety in the event of an H₂S release and expects operators will be prepared to deal with all emergencies that may occur at a well site. Sour wells which exhibit a high H₂S release potential or those near dwellings require site-specific emergency response plans which must be reviewed/audited by the Board. The Board's policy is to ensure that, if there is a significant release of H₂S, the health and safety of the public must be protected either by their evacuation from or shelter in the area or, if evacuation is not practical, by ignition of the well.

3.1 When a Plan is Required

An emergency response plan is required for the drilling of a sour well when:

- (1) the well is classified as a critical sour well (Section 4),
- (2) there are one or more dwellings, public facilities, work sites, places of business, or similar activities within the emergency planning zone, or
- (3) the Board decides that a plan is required for other reasons.

3.2 Selection of Emergency Planning Zone

The appropriate emergency planning zone (EPZ) must be carefully selected and must be adequate to ensure the safety of the public near the well. The size and shape of the zone must reflect the maximum drilling H₂S release rate but must also have regard for the local terrain and density of population in the area.

To calculate the EPZ, use the cumulative drilling release rate (RR) using the following formulas:

- C if $RR < 0.3 \text{ m}^3/\text{sec}$, $EPZ = RR^{0.58} \times 2 \text{ km}$
- C if $RR > 0.3 \text{ m}^3/\text{sec}$ but $< 8.6 \text{ m}^3/\text{sec}$, $EPZ = RR^{0.68} \times 2.3 \text{ km}$
- C if $RR > 8.6 \text{ m}^3/\text{sec}$, $EPZ = RR^{.81} \times 1.9 \text{ km}$

The Board will consider reduced planning zones for wells which exhibit very high H₂S release rate potential ($+3.0 \text{ m}^3/\text{s}$) and which are near densely populated areas that may be difficult or impossible to evacuate in the event of an emergency. In such cases, the ignition criteria and other response actions specified to ensure public safety must be appropriate for the reduced planning zone.

3.3 Emergency Response Plan Contents

In 1991, CPA/IPAC prepared "Guidelines for Preparation of Public Safety Emergency Response Plans for Sour Gas Drilling, Completion and Servicing." The Board has accepted these guidelines as minimum standards for emergency response plans. However, the Board retains the right to decide the amount of detail required in each plan submitted for review/audit. The Board stresses that each plan must consider site-specific circumstances. Variations in the plans can be expected based on factors such as the geological prognosis of the well, population density and distribution, and the consequences of a blowout.

The Board stresses that public input from local residents and municipal administrators is an integral part of preparing an effective emergency response plan. In some instances it may be necessary to hold public meetings to obtain this input.

The CPA/IPAC guide describes the minimum content and specific detail required in an emergency response plan. The following list identifies major components and summarizes the key items to be addressed in a plan.

(1) Summary

This section is a summary of the key facts about the proposed well and the emergency response plan.

(2) Emergency Definition and Action

This section describes the various circumstances that could lead to a sour gas release and the intended response. It defines the various stages of alert and describes the action for each stage. In addition, it describes the responsibility of company and government personnel involved in an emergency.

(3) Evacuation Procedures

This section defines the criteria to be used to initiate an evacuation and describes how the evacuation would be carried out.

Details respecting the proposed air quality monitoring program and communication procedures are also addressed.

(4) Ignition Criteria

This section defines the ignition criteria and circumstances leading to the deliberate ignition of the well. The licensee must have clear and specific plans in place to ignite an uncontrolled flow where the size of the emergency planning zone has been reduced because of population density.

(5) Resident Information Package

This section includes a copy of the Resident Information Package that was or will be left with residents within the emergency planning zone. The package provides a brief summary of the proposed well and operator, a summary of evacuation and ignition procedures, emergency telephone numbers, and a description of the hazards of H₂S and sulphur dioxide.

(6) Contact Information

This section provides a listing of the residents, company personnel, and government agencies that would be contacted in the event of a sour gas release.

(7) Maps

This section includes the maps necessary to show:

- (a) the selected emergency planning zone and the dwellings, other developments, roads, and topographical features within the zone;
- (b) an area equal to at least twice the size of the emergency planning zone and the public facilities, urban centres, and evacuation routes within the area.

3.4 Specific Requirements

- (1) A copy of the approved emergency response plan must be on site during drilling operations, prior to drilling out the surface casing, and during all completion or servicing operations of designated critical sour wells.
- (2) Copies of the approved emergency response plan must be sent to each of the following within five (5) business days of receiving the emergency response plan approval:

Alberta Environmental Protection
 Alberta Transportation & Utilities
 Workplace Health, Safety & Strategic Services; Occupational Health & Safety Services
 Appropriate Regional Health Authority
 Appropriate detachment of the RCMP
 Alberta Land & Forest Service
 Municipal governments, where applicable

- (3) For critical sour wells, the operator shall hold a meeting to review the emergency response plan before drilling into the potential sour zones. The operator, its contractors, Board staff, and the government departments and agencies listed in (2) above should attend.
- (4) For critical sour wells where the emergency planning zone includes all or a portion of an urban centre, the Board requires continuous mobile monitoring on lease during the drilling, servicing or completion of the potential sour zones. The Board will review the need for continuous mobile electronic monitoring for other sour wells on a site-specific basis.

4 DRILLING REQUIREMENTS AT CRITICAL SOUR WELLS

The following requirements apply to the drilling of a critical sour well. The Board also requires the licensee to meet or exceed the Alberta Recommended Practices (ARPs) when drilling critical sour wells. Volume 1 (Drilling) and Volume 2 (Completing and Servicing) are available through the Petroleum Industry Training Service (PITS).

Each component of the drilling plan must include documentation on the following items. Failure to comply with these requirements may result in the immediate suspension of operations.

4.1 Drilling Plan

- (1) Well Design:
 - (a) Casing details - Casing depth, grade, weight, size; for surface, intermediate and production casing. Details of the surface casing bowl.
 - (b) Geological zones, including identification of sour and critical sour zones must be shown on a wellbore diagram.
 - (c) Details of casing design and sour service suitability of the casing grades referencing ARP Volume 1 Section 1.6. If grades other than L-80 are proposed, details on chemistry specifications must be reviewed and documented. Casing design for horizontally-drilled wells must also address the additional stresses and loads.
- (2) Offset well map.
- (3) Summary of hole problems expected, solutions, and reasons for selecting casing setting depths.
- (4) BOP Stack - The configuration used and its pressure rating; and if blind shear rams were not planned, the reasons must be included using the criteria set out under **Equipment**.
- (5) BOP Manifold - The configuration and pressure rating, having regard for the number of mud-gas separators installed.
- (6) Mud-Gas Separators - The number of mud-gas separators planned. If only one mud-gas separator was planned, include the reasons using the criteria set out under **Equipment**.
- (7) Drill Pipe - The grade, type (new/used) and class of drill pipe. If grade is other than E, include:
 - (a) A discussion of sour-service suitability referencing ARP Volume 1, Section 1.2.
 - (b) Drill pipe design of both the grade planned and grade E, including a comparison

of overpull tensile margins at the surface or other design factors affecting the choice of grade.

- (c) H₂S exposure control planned, referencing ARP Volume 1, Sections 1.2 and 1.7.

As an alternative to the above, if the planned grade will meet the same hardness limitations as grade E (see ARP Volume 1, Section 1.2), make a statement to this effect.

- (8) Practices - If underbalanced drilling is planned, a detailed description of modifications and additions to equipment must be described referencing ID 94-3 "Underbalanced Drilling," or any future requirements resulting from the Drilling and Completions Committee (DACC) subcommittee's review of sour well underbalanced drilling.
- (9) Drilling Fluid System - Provide the type, the density, the pH level, the amount of weight material on site, if the system will be pretreated with H₂S scavenger, and the type of additional drilling fluid that will be kept on site.
- (10) Blowout Insurance - A statement that the company (including working interest owners) is self-insured, or other proof of insurance must be filed and available for audit.
- (11) Inspection and Testing Procedures - Provide a description of the inspection and testing procedures designed to ensure that all equipment is fully operational prior to the well reaching the critical depth and procedures to ensure that a state of readiness is maintained.

Prior to drilling any critical well, a drilling plan must be prepared and copies must be:

- C on site during drilling operations.
- C one copy must be filed with the appropriate Board field centre office for use during a site inspection.
- C available for audit of the application for well licence, or filed with the well licence application if the application is to be heard at a public hearing.

4.2 Well Design

- (1) Intermediate casing shall be set to an appropriate point above the zone from which the first critical sour gas or oil is expected, or at a point before the cumulative release rate becomes critical.
- (2) Notwithstanding the above, the Board may exempt an applicant at the well licencing stage from the requirements to set intermediate casing. To apply for this exemption, applicants must file a non-routine application by indicating a "No" response in Step 11 of Schedule 4-Guide 56 and must attach the following to support their request:

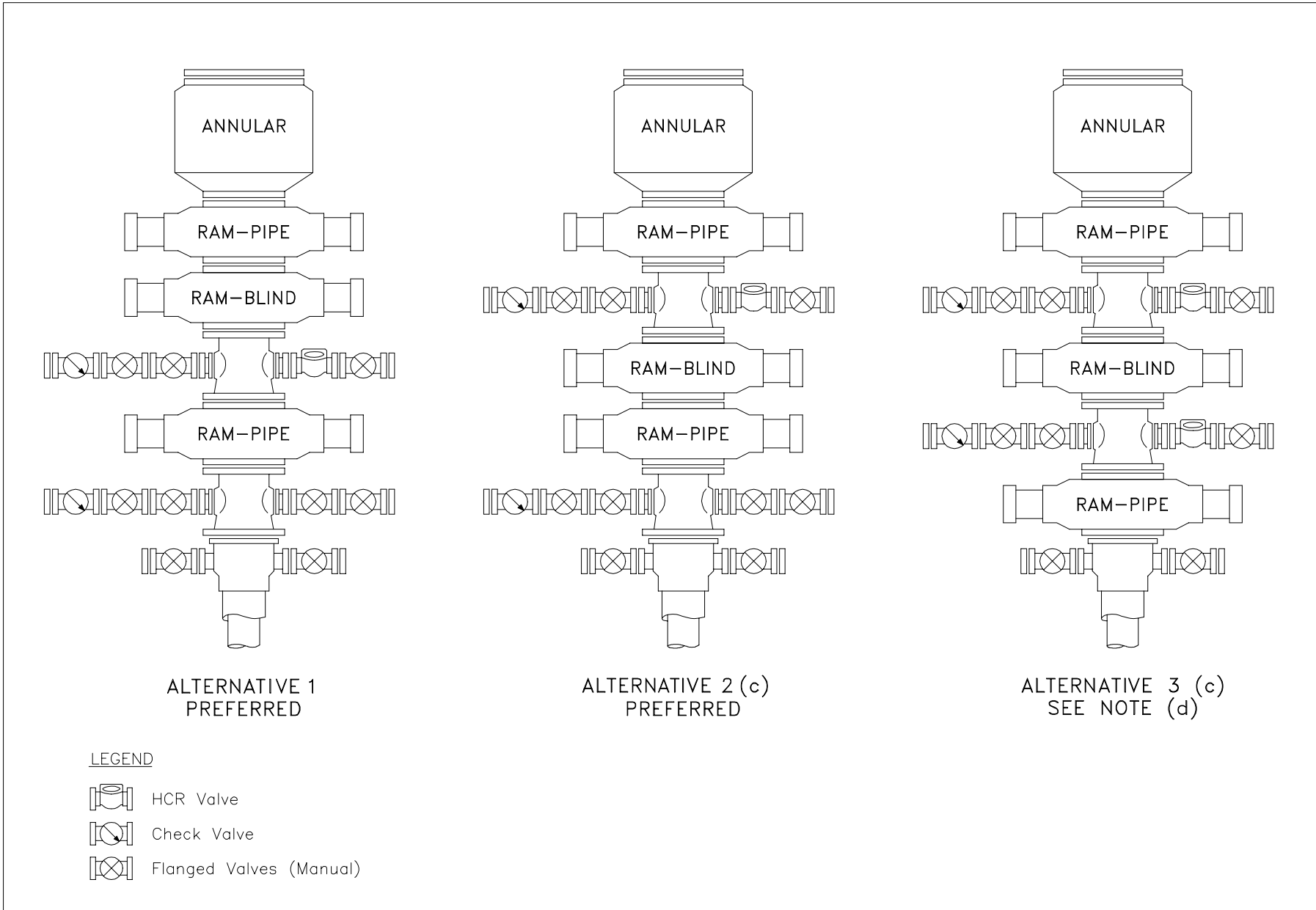
- (a) The geological prognosis of the proposed well. The well must be in a known and established field area which offsets existing development.
 - (b) Summary of offset wells confirming no significant lost circulation problems or other adverse drilling conditions.
 - (c) Summary of drill stem test pressures, mud densities, or other information to verify normal formation pressures are expected.
 - (d) Kick tolerance calculations indicating the ability of surface or other casing in the well bore to handle a 3-cubic-metre gas kick.
- (3) Intermediate and production casing grades must be suitable for sour service, or if the Board grants exemption from setting intermediate casing, the surface casing grade must be suitable for sour service.
- (4) If the Board approves exemption from setting intermediate casing, the wellbore integrity, including the casing and open hole sections, must be evaluated by an open-hole integrity test prior to penetrating the critical zone and must be found capable of holding anticipated formation pressures before continuing to drill without intermediate casing.
- (5) The intermediate casing burst shall be designed, as a minimum, to 67 per cent of maximum bottom-hole pressure. Re-entry of a critical sour well will require the operator to prove pressure integrity of at least 67 per cent of maximum bottom-hole pressure by pressure testing existing casing prior to drilling into the critical sour zone. New casing run prior to penetrating the critical zone, must be designed as described above.
- (6) For horizontally-drilled critical sour wells, casing design must be designed for additional stress factors including tri-axial loading.

4.3 Equipment

4.3.1 BOP Stack

- (1) Minimum stack components shall consist of an annular preventer, two spools, and three rams - except that for maximum projected depths less than 1800 m, then flanged side outlets on the lower ram preventer may be substituted for the lower drilling spool. The configuration of the BOP stack shall conform to the figure on page 14. Blind shear rams must be used for any critical sour well where:

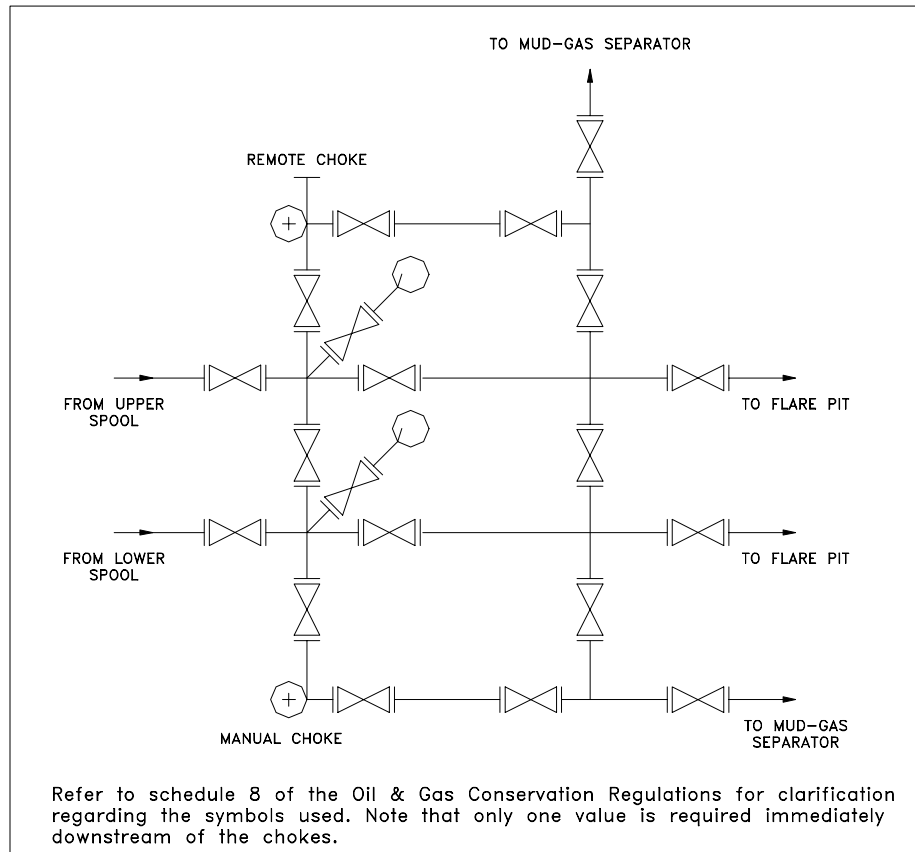
- C the calculated emergency planning zone size intersects the boundaries of an urban centre, or
 - C the calculated emergency planning zone encompasses more than 100 occupied dwellings.
- (2) Whenever blind shear rams are not installed, the operator should evaluate running a drill string float/internal BOP.
 - (3) All pressure-containing components within the BOP stack, inclusive of attached valves and choke lines through to the outside valves of the choke manifold, with the potential to be exposed to H₂S gas, shall be constructed of materials which meet the standards of the National Association of Corrosion Engineering Standard (NACE) MR-01-75.
 - (4) The BOP master control shall be installed at a location remote from the rig floor.
 - (5) The accumulator system shall be sized such that when charged to its operating pressure and with the recharge pump off, there shall be sufficient volume to open the HCR, close the annular preventer on drill pipe, and close, open, and close one ram preventer. The final accumulator pressure shall not be less than 8400 kPa. In addition, the accumulator must have sufficient volume to close the annular preventer on open hole. Where blind shear rams are run, the accumulator size must be increased, or a separate accumulator system installed, to provide sufficient volume to shear drill pipe.
 - (6) Welded casing bowls shall be welded in accordance with an acceptable welding procedure developed from API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, NACE MR-01-75, and Section IX of ASME, Boiler and Pressure Vessel Code. ARP Volume 1, Section 1.15 contains additional details regarding welding procedures.
 - (7) Threaded casing bowls shall be manufactured in accordance with API Spec 6A, the make-up procedures and torque in accordance with API RP 5C1, Care and Use of Casing and Tubing, and the thread compound used in accordance with API Bul 5A2, Bulletin on Thread Compounds.
 - (8) Drilling components installed between the top flange of the uppermost blowout preventer and the bottom of the rig floor shall be constructed to permit their removal while drill pipe or other equipment is in the hole.



ALTERNATIVE BOP STACK CONFIGURATIONS – CRITICAL SOUR WELLS

4.3.2 BOP Manifold

The BOP manifold configuration shall be as illustrated in the figure below.



MANIFOLD LAYOUT – CRITICAL SOUR WELLS

ID 97-6
EUB

- (1) The manifold and piping shall provide complete redundancy from the BOP stack, through the manifold, to the mud-gas separators, and finally to the flare pit.
- (2) Where only one mud-gas separator is being used, redundancy from the manifold to the single mud-gas separator, and from the mud-gas separator to the flare pit is not required.
- (3) A separate bleed-off line from each spool to a separate manifold wing (side) is required and must be equipped with a separate casing pressure gauge.
- (4) A remote, hydraulic operated, non-rubber sleeve choke is required on the primary manifold wing (upper BOP spool) and a manual operated choke is required on the secondary manifold wing (lower BOP spool).

- (5) BOP manifolds shall be filled with suitable water-soluble non-freezing fluids and be adequately heated during the winter season.

4.3.3 Mud-Gas Separators

- (1) Two mud-gas separation devices are required for the drilling of critical sour wells.
- (2) One mud-gas separator is acceptable provided:
- the maximum potential H₂S release rate is less than 2.0 m³/s and the calculated EPZ does not intersect an urban centre,
 - the geological prognosis of the proposed well is clearly established on the basis of offset wells,
 - normal formation pressures are expected, and
 - no significant lost circulation is expected.
- (3) The primary device must be an atmospheric, open bottom, mud-gas separator and must conform to the specifications detailed in Table 4.1. The secondary device may be an enclosed mud-gas separator.

Table 4.1 ATMOSPHERIC, OPEN-BOTTOM, MUD-GAS SEPARATOR VESSEL AND VENT LINE DIAMETER REQUIREMENTS FOR CRITICAL SOUR WELL DRILLING

Drilling Depth (m) Less Than	Minimum Vessel Diameter ³ (mm)	Minimum Vent Line Diameter (mm)	
		with 1 m of Fluid Head	with 2 m of Fluid Head
750	355.6	101.6	101.6
1 800	609.6	152.4	127.0
2 700	660.4	172.9	152.4
3 600	762.0	203.2	152.4
5 000+	914.4	254.0	203.2

- (4) All materials used in vessels, inlet lines, and vent lines for mud-gas separators must be suitable for sour service and have a maximum yield strength not exceeding 550 megapascals.

³

Vessel diameter was determined using a vapour load constant (k) of 0.11 m/s.

Suitable materials are as follows:

C Regular Materials

Plate: ASTM A516 Grade 65
ASTM A516 Grade 70

Pipe: ASTM A106 Grade B
ASTM A53 Grade B
API 5L Grade B
API 5L Grade X42
CSA Z245.1 Grade 241
Category 1
API H40, J55, K55 seamless casing (if hardness tested)

C Low-temperature Materials

Plate: ASTM A516 Grade 65 c/w
Supplementary 5
ASTM A516 Grade 70 c/w
Supplementary 5
Pipe: ASTM A333 Grade 6
CSA Z245.1 Grade 241
Category II

(5) Mud-gas separator vent lines shall slope down towards the flare pit.

4.3.4 Drill Pipe

- (1) Selection criteria for drill string outlined in Volume 1 of the Drilling ARP, Section 1.2.2 should be referenced to determine most appropriate materials.
- (2) Used drill pipe must be inspected in accordance with Section 10 of API RP 7G, Drill Stem Test Design and Operating Limits. The inspection personnel's qualifications, equipment, and procedures must be in accordance with API RP 5A5, Field Inspection of New Casing, Tubing and Plain-End Drill Pipe.
- (3) New and used drill pipe must be hardness tested, and abnormally hard joints must be removed from the drill string in use.
- (4) Only premium or better class drill pipe (API RP 7G) shall be used for critical sour wells.
- (5) The Board's Operations Group must be notified immediately of any drill string failures.

4.3.5 Drill String Valves

- (1) Lower kelly cocks and stabbing valves must be certified by the manufacturer to be capable of routinely opening with 7000 kilopascals (kPa) pressure below the valve.
- (2) Lower kelly cocks must be installed.

4.3.6 Monitoring Equipment

- (1) Where water-based drilling fluid is in use, a continuous pH monitoring system must be installed and located as close as possible to the flowline discharge of the drilling rig. This monitoring unit is to be equipped with an alarm which will indicate a drop in pH.
- (2) Sulphide content must be monitored by either a continuous sulphide monitor, or by hourly HACH tests which must be recorded throughout the critical period, and whenever sulphides are detected. A Garret Gas Train Test must be conducted every two (2) hours. A record of the sulphide content in the mud must be maintained throughout the critical period.
- (3) Ambient H₂S detection is required and must consist of a continuous H₂S detection monitoring system that activates audible and visual alarms near the driller's position when sensing ambient air H₂S concentrations of 10 parts per million (ppm) or greater. The system must consist of at least one sensor located at the shale shaker. Additional sensors may be placed at other locations such as the bell nipple, rig floor, and mud mixing unit. Sensors must be able to detect H₂S concentrations of 5 ppm and greater. Qualified personnel should be on site to test and provide maintenance to this instrumentation.
- (4) At least one portable ambient H₂S concentration detection device shall be on location.
- (5) Each rig shall have installed and operate an automated mud tank volume monitoring system that meets the following specifications:
 - (a) The system will be designed and installed so that it is capable of detecting a gain or loss of 1.0 m³ in total drilling fluid volume. This will require a probe in each active compartment.
 - (b) A fluid volume monitoring station with an alarm must be located at or near, and be visible to, the driller's position. The monitor must be equipped with a recording chart.
 - (c) The monitoring station must have a large, bright, flashing indicator light which will come on automatically whenever the alarm is shut off.
 - (d) When drilling, the alarm must be set to detect a gain or loss in total drilling fluid volume of not more than 2.0 m³.
- (6) Indicators must be in operation for measuring hook load, pump pressure, pump strokes per minute, and table torque. All such indicators must be visible from the driller's position.

- (7) A continuous recording device is required to record rate of penetration, pump pressure, pump strokes per minute, hook load, rotary table revolutions per minute (rpm), and rotary torque. This record must be kept for the entire drilling operation and be made available for inspection at the well site until rig release.
- (8) A trip tank is required which is designed such that a change in level of 25 millimetres (mm) equals a volume change of not more than 0.075 m^3 . This equates to a maximum surface area of 3.0 m^2 . A minimum usable trip tank volume of 3.0 m^3 is recommended.
- (9) The hole fill volume must be measured either by manual gauging of the trip tank or by reading a mechanical or automated system visible at the driller's position. If a mechanical monitoring system is in use, the volume increments on the monitoring board must be 0.1 m^3 . If an electronic probe is used, the monitor's measurement increments must not exceed 0.0375 m^3 and the monitor must have a readout to two (2) decimal places.

4.4 Practices

4.4.1 Tripping

- (1) The hole must be filled to surface after every 15 singles (maximum) of drill pipe and after every three (3) singles (maximum) of drill collars are pulled.
- (2) A trip record is required for every trip. During the critical period it shall be signed and dated by the operator's well site supervisor and the contractor's rig manager and maintained at the well site until rig release.
- (3) Each trip record must show the actual volume used each time the hole is filled as specified above. The cumulative total fill volume must also be recorded after each successive fill. On the same page the record must show the theoretical volume required at each fill point, plus the theoretical cumulative fill volumes.
- (4) Minimum five (5)-minute flow checks are required at each of the following stages: prior to beginning a trip out of the hole; after pulling the first 15 singles of drill pipe from the hole; prior to pulling the first stand of drill collars from the hole; and after all the drill string is out of the hole.

4.4.2 Testing and Coring

- (1) Critical sour zones shall not be drill stem tested.
- (2) Directional surveys are required at a frequency of 60 m for horizontal, directional and deviated wells.
- (3) Coring is permitted at critical sour wells, however if the well is located in an exploratory/non-development setting, the following practice must be adhered to:
 - (a) The porosity of the critical zone must be penetrated prior to tripping out for the coring assembly, to ensure normal pressures, or

- (b) If upper porous interface must be cored, the ability to circulate above the core barrel must be available (e.g. ported string).

4.4.3 Underbalanced Drilling

Equipment requirements will change significantly on a critical sour well to be drilled underbalanced. In these cases, the requirements of ID 94-3 must be met in addition to this directive.

Licensees must ensure that all equipment exposed to sour fluids (including tubulars) be constructed of materials with suitable performance properties for the intended service.

Note: The Board will not approve sour underbalanced drilling operations which place residents inside the calculated EPZ's - until the regulatory requirements for these types of wells have been reviewed, assessed and the findings published.

4.5 Personnel

4.5.1 Supervision

- (1) On-site supervisors must have a current PITS Second Line Supervisor BOP Well Control certificate, H₂S Alive certification and experience in drilling sour wells.
- (2) During the critical period of drilling operation, sufficient supervision must be on site and available so that no individual supervisor is required to work a shift longer than 12 hours.

4.5.2 Rig Crew

- (1) On-site rig managers must have a current PITS Second Line Supervisor BOP Well Control certificate, and drillers must have a current PITS First Line Supervisor BOP Well Control certificate.
- (2) On-site rig managers and drillers must have H₂S Alive certification and experience in drilling sour wells.
- (3) Each driller must have an adequate understanding of the correct operation of all kick detection and monitoring equipment.
- (4) A minimum five (5)-man drilling crew shall be maintained and all crew members shall have H₂S Alive certification.

4.5.3 Service Personnel

- (1) Key on-site service personnel including mud-men, loggers, geologists, etc. shall have previous experience in sour well drilling operations.
- (2) All well-site personnel shall be trained in H₂S safety.

4.5.4 Safety Specialists and Equipment

During the critical period of the drilling operation, safety personnel and adequate safety equipment for all workers must be on site (minimum requirements are specified by the Occupational Health & Safety (OH&S) Act and Regulations).

4.6 Inspection

A weekly detailed rig inspection shall be performed by the operator and contractor. An inspection check sheet shall be used and retained.

- (1) A detailed inspection⁴ and blowout prevention drill shall be conducted:
 - (a) prior to drilling out the surface casing,
 - (b) prior to drilling out the intermediate casing, and
 - (c) within the 24-hour period prior to penetrating the critical sour zone (if intermediate casing is set immediately above the critical zone, this inspection would coincide with (b) above).
- (2) The licensee must notify the appropriate EUB field centre at least 48 hours prior to these inspections and drills being initiated.

⁴

These inspections must include pressure testing all equipment and casing in accordance with EUB Guide 36, unless the well is being re-entered, then casing must be pressure-tested to 67 per cent of maximum bottom-hole pressure. Note that 30-day casing wear tests must also be conducted in accordance with section 8.141(3) of the Oil and Gas Conservation Regulations.

4.7 Blowout Insurance

Companies licensing a critical sour well must either be self-insured to cover the costs of a blowout, or must obtain significant liability insurance. Insurance amounts depend on the well depth and must include provision for pollution and seepage, evacuation expense, underground blowout, and care/custody and control. In addition, if the well is a "joint venture," the company must either hold insurance for 100 per cent of the working interest, or have a copy of insurance policies for the interest of each partner.

5 ENFORCEMENT

The consequences for failing either an application audit, an operations audit or field inspection will vary depending on the severity and frequency of noncompliance. For minor/infrequent noncompliance, the Board will use enforcement options such as warnings, increased audit frequency, and temporary shut-down of the operation to rectify the problem. The Board will use such enforcement options as indefinite shut-down of the operation or suspension of approval for severe/frequent non-compliance.

APPENDIX 1 Definitions

For the purpose of this directive:

- (1) **Completion/Service Stage:** includes all operations which are continuously attended subsequent to the drilling stage, and which are necessary to prepare the well to produce, or after a period of production, to restore the well or to repair the well.
- (2) **Critical Sour Well:** a designation that reflects the proposed well's proximity to an urban centre and its maximum potential hydrogen sulphide (H₂S) release rate during the drilling stage. The casing flow or open-hole flow configuration is assumed in arriving at this designation. Included are:
 - (a) any well from which the maximum potential H₂S release rate is greater than 0.01 cubic metres per second (m³/s) but less than 0.1m³/s and which is located within 500 metres (m) of the corporate boundaries of an urban centre, or
 - (b) any well from which the maximum potential H₂S release rate is greater than 0.1 m³/s but less than 0.3 m³/s and which is located within 1.5 kilometres (km) of the corporate boundaries of an urban centre, or
 - (c) any well from which the maximum potential H₂S release rate is greater than 0.3 m³/s but less than 2.0 m³/s and which is located within 5 km of the corporate boundaries of an urban centre, or
 - (d) any well from which the maximum potential H₂S release rate is greater than 2.0 m³/s, or
 - (e) any other well which the Board classifies as a critical sour well having regard to the maximum potential H₂S release rate, the population density, the environment, the sensitivity of the area where the well would be located, and the expected complexities during the drilling phase.
- (3) **Critical Period:** any time or depth starting with some reasonable period prior to when a well has penetrated or may have penetrated any formation (or combination of formations) that may be capable of flowing H₂S at critical sour well rates, and continues until such formations have been rendered incapable of flowing into the wellbore by running and cementing casing, or by cement abandonment plug, or approval has been given by the Board to reclassify the well or formation as no longer critical.
- (4) **Drilling Stage:** includes all operations which are continuously attended, from spudding-in until production casing is cemented or the well is abandoned.
- (5) **Emergency Planning Zone:** an area surrounding a well where residents or other members of the public may be at risk in the event of an uncontrolled release of H₂S and the operator must be prepared to respond accordingly.

- (6) **Flow Configuration:** the well equipment and flow configurations to be considered in determining H₂S release rate at various stages of a well's drilling or producing life. These are:
- (a) casing flow or open-hole flow where reservoir fluids are free to flow up the casing or open hole without any other tubular goods in the wellbore,
 - (b) tubing and annular flow where reservoir fluids flow up the tubing and the annular space between the tubular string and the casing or open hole, and
 - (c) tubing flow where flow is only up the tubing.
- (7) **Level Classification:** a designation to stipulate separation distances of sour wells for land-use and public safety purposes. The level classification for sour wells is determined by assessing the maximum potential surface H₂S deliverability that can be attained against zero back pressure during the suspended/producing stage of a well. A well may be completed with a packer and capable of flowing through tubing only, or completed without a packer and capable of flowing through tubing and also up the annulus. The appropriate flow configuration must be considered in arriving at the level classification.
- (8) **Potential H₂S Release Rate:** the calculated H₂S deliverability that can be attained at surface against zero back pressure with various flow configurations, expressed using the unit of cubic metres per second (m³/s) at standard pressure and temperature conditions.
- (9) **Public Facility:** a public building such as a hospital, rural school, or a major recreational facility situated outside of an urban centre; and for the purpose of this directive, includes other developments the Board, after consultation with appropriate interested parties, may designate as a public facility based on the complexity of evacuation taking into consideration the number of people using the facility and the frequency and duration of their use.
- (10) **Separation Distance:** the required distance between a sour well and developments such as individual permanent dwellings, unrestricted country development, public facilities, and the corporate boundaries of urban centres.
- (11) **Sour Gas:** natural gas, including solution gas, containing hydrogen sulphide (H₂S).
- (12) **Sour Well:** any oil or gas well expected to encounter sour gas-bearing formations during drilling or any oil or gas well capable of producing sour gas.
- (13) **Surface Improvement:** means a railway, pipeline or other right of way, road allowance, surveyed roadway, dwelling, industrial plant, aircraft runway or taxiway, building used for military purposes, permanent farm buildings, school, or church.
- (14) **Suspended/Producing Stage:** includes all operations which are not continuously attended, at wells that may or may not be capable of producing.

- (15) **Unrestricted Country Development:** any collection of permanent dwellings situated outside of an urban centre and having more than eight permanent dwellings per quarter section; and for the purpose of this directive includes any similar development the Board may designate as an unrestricted country development.

- (16) **Urban Centre:** a city, town, new town, village, summer village, hamlet with not less than 50 separate buildings each of which must be an occupied dwelling, or other incorporated centre, and for the purpose of this directive includes any similar development the Board may designate as an urban centre.

APPENDIX 2 References

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EXTRACTED FROM EUB BULLETIN 2004-18 - APPENDIX 2

Consequential Changes That Will Be Required to Other Existing EUB Documents as a Result of Implementation of *Directive 36 (June 2004 edition)*

EUB Document	Change
<p><i>ID 97-6: Sour Well Licensing and Drilling Requirements</i></p>	<p>Certain requirements of <i>ID 97-6</i> have been modified and incorporated into <i>Directive 36</i>, as follows:</p> <p><i>ID 97-6</i>, Section 4.2(1): Well Design has been incorporated in <i>Directive 36</i>, Section 16.4.2: Intermediate Casing.</p> <p><i>ID 97-6</i>, Section 4.3.1(1): BOP Stack has been modified and incorporated in <i>Directive 36</i>, Figure 5: BOP Stack Configurations Critical Sour Wells (Section 15) and Section 16.4.4: Shear Blind Rams.</p> <p><i>ID 97-6</i>, Section 4.3.1(3): BOP Stack has been incorporated in <i>Directive 36</i>, Section 1.1.1: Metallic Material for Sour Service.</p> <p><i>ID 97-6</i>, Section 4.3.1(4): BOP Stack has been incorporated in <i>Directive 36</i>, Section 6.3.3: Master Hydraulic Control Manifold Location.</p> <p><i>ID 97-6</i>, Section 4.3.1(5): BOP Stack has been modified and incorporated in <i>Directive 36</i>, Section 6.1: Accumulator System.</p> <p><i>ID 97-6</i>, Section 4.3.1(6 and 7): BOP Stack has been incorporated in <i>Directive 36</i>, Section 1.2: Casing Bowls.</p> <p><i>ID 97-6</i>, Section 4.3.1(8): BOP Stack has been incorporated in <i>Directive 36</i>, Section 1.3: Drill-Through Components.</p> <p><i>ID 97-6</i>, Section 4.3.2 (1 through 4 inclusive): BOP manifold has been incorporated in <i>Directive 36</i>, Section 2: Bleed-Off and Kill Systems and Figure 6: Choke Manifold – Critical Sour Well (Section 16).</p> <p><i>ID 97-6</i>, Section 4.3.2(5): BOP Manifold has been modified and incorporated in <i>Directive 36</i>, Section 5: Winterizing.</p> <p><i>ID 97-6</i>, Section 4.3.3 (1 through 5 inclusive): Mud-Gas Separators has been modified and incorporated in <i>Directive 36</i>, Section 2: Bleed off Systems.</p> <p><i>ID 97-6</i>, Section 4.3.4 (4 and 5): Drill Pipe has been incorporated in <i>Directive 36</i>, Section 16.4.5: Drill Pipe.</p> <p><i>ID 97-6</i>, Section 4.3.5 (1 and 2): Drill String Valves has been modified and incorporated in <i>Directive 36</i>, Section 1.4: Stabbing Valve and Inside BOP and Section 1.5: Lower Kelly Cock Valve.</p> <p><i>ID 97-6</i>, Section 4.3.6 (1, 3 and 4): Monitoring Equipment has been modified and incorporated in <i>Directive 36</i>, Section 16.4.7: H₂S Monitoring.</p> <p><i>ID 97-6</i>, Section 4.3.6 (2): Monitoring Equipment has been modified and incorporated in <i>Directive 36</i>, Section 16.4.8 Sulfide Monitoring.</p> <p><i>ID 97-6</i>, Section 4.3.6(5): Monitoring Equipment has been modified and incorporated in <i>Directive 36</i>, Section 9.2.2: Automated (Electronic) Mud Tank Fluid Volume Monitoring System.</p> <p><i>ID 97-6</i>, Section 4.3.6(6 and 7): Monitoring Equipment has been incorporated in <i>Directive 36</i>, Section 16.4.6: Indicators and Recording Devices.</p> <p><i>ID 97-6</i>, Section 4.3.6(8 and 9): Monitoring Equipment has been incorporated in <i>Directive 36</i>, Section 9.3.3: Critical Sour Wells.</p>

(continued)

ID 97-6, Section 4.4.1 (1 through 4 inclusive): Tripping has been modified and incorporated in Directive 36, Section 11.3: Tripping.

ID 97-6, Section 4.4.2(1 and 3): Testing and Coring has been incorporated in Directive 36, Section 16.4.9: Testing and Coring.

ID 97-6, Section 4.4.2(2): Testing and Coring has been modified and incorporated in Directive 36, Section 17.5: Directional Surveys – Critical Sour Wells.

ID 97-6, Section 4.4.3: Underbalanced Drilling has been incorporated in Directive 36, Section 16.4.10: Underbalanced Drilling.

ID 97-6, Section 4.5.1(1 and 2): Supervision has been modified and incorporated in Directive 36, Section 10.1: Well-Site Supervision, Section 10.2.2: Second-Line Supervisor’s Well Control Certificate, and Section 16.4.11: Personnel.

ID 97-6, Section 4.5.2(1): Rig Crew has been modified and incorporated in Directive 36, Section 10.2.1: First-Line Supervisor’s Certificate and Section 10.2.2: Second-Line Supervisor’s Well Control Certificate.

ID 97-6, Section 4.5.2(2 and 4): Rig Crew has been incorporated in Directive 36, Section 16.4.11: Personnel.

ID 97-6, Section 4.5.2(3): Rig Crew has been incorporated in Directive 36, Section 9: Mud Tanks and Fluid Volume Monitoring Systems.

ID 97-6, Section 4.5.3(1 and 2): Service Personnel has been incorporated in Directive 36, Section 16.4.11: Personnel.

ID 97-6, Section 4.5.4: Safety Specialists and Equipment has been incorporated Directive 36, in Section 16.4.11: Personnel.

ID 97-6, Section 4.6(1 and 2): Inspection has been incorporated in Directive 36, Section 18.2 Detailed Inspections.