Directive 077

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Pipelines – Requirements and Reference Tools

Contents

1 Introduction 1

1.1 Purpose of This Directive 1

1.2 AER Requirements 1

1.3 What's New in This Edition 1

1.4 How to Use This Directive 1

2 External Corrosion Prevention Coatings Under Pipeline Insulation 2

2.1 Corrosion Under Pipeline Insulation 2

2.2 Insulated Pipeline Corrosion Management 2

2.3 Exempted Pipelines 3

3 High-Performance High-Density Polyethylene Pipe in Oil and Gas Service 3

4 Overpressure Protection for Pipelines Connected to Artificial Lift Equipment 3

5 Pipeline Pressure Testing Using Liquid Test Media Other Than Fresh Water 5

6 Pipeline Pressure Testing Using Gaseous Test Media 6

7 Temporary Surface Pipelines for Well Testing or Bypass 8

8 Temporary Surface Pipelines for Water Conveyance 9

8.1 Approval and Notification Process 10

8.1.1 Group 1 TSPW Deployment Notification 11

8.1.2 Group 2 and 3 TSPW Approval 11

8.1.3 Group 2 and 3 TSPW Deployment Notification 11

8.1.4 TSPW Route Map 12

8.2 Extension Requests and Amendments 12

8.3 Consent and Notification 13
8.4 Documentation Requirements 13
8.5 Technical Requirements 13
8.5.1 Route Selection and TSPW Placement 13
8.5.2 Materials 16
8.5.3 Deployment 16
8.5.4 Commissioning 18
8.5.5 Operations 19
8.5.6 Operations Surveillance 20
8.5.7 Incident Response and Reporting 21
8.5.8 End of Operations 22

9 Elevated-Temperature Pipelines 23
9.1 Introduction 23
9.2 Exemptions 24
9.3 CSA Z662 – Clause 14 / Annex I 25
9.4 Application for a Pipeline Licence 25
9.5 Field Construction and Inspection 25
9.6 Pressure Testing 26
9.7 Operations 26
9.8 Release of Product and Contact Damage (Failure Investigation) 26

10 Comingling of Oil and Gas in a Single Pipeline 27
10.1 Introduction 27
10.2 Criteria for Pipeline Licensing of Commingled Production 27

Appendix 1 Definitions 29

Appendix 2 Interpretation of Jurisdictional Relationships for the Design of Pipelines, Pressure Equipment, and Pressure Piping 31

Appendix 3 Jurisdictional Interpretation for Elevated-Temperature Pipelines 47

Table 1. Steel pipe test section lengths for volumes of 125 m^3 7
Table 2. Water groups for TSPW conveyance 10

Abbreviations

ABSA	Alberta Boilers Safety Association
AER	Alberta Energy Regulator
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
CRN	Canadian Registration Number
GOR	gas-oil ratio
HDPE	high-density polyethylene
MOP	maximum operating pressure
OGCA	*Oil and Gas Conservation Act*
OGCR	*Oil and Gas Conservation Rules*
PEEO	*Pressure Equipment Exemption Order*
PESR	*Pressure Equipment Safety Regulation*
SCA	*Safety Codes Act*
TSP	temporary surface pipeline
TSPW	TSPs for water conveyance

1 Introduction

1.1 Purpose of This Directive

Directive 077: Pipelines – Requirements and Reference Tools was first published in 2011 and amalgamated information about **pipelines** into one directive. This information previously resided in other Alberta Energy Regulator (AER) directives, informational letters, interpretive documents, and reference tools.

This directive provides testing and operational requirements for ensuring pipelines, including temporary pipelines, are operated safely and in accordance with regulations and industry standards.

In this directive, defined terms are set in **boldface** at first use, and the definitions are provided in appendix 1.

1.2 AER Requirements

Following AER requirements is mandatory for the responsible duty holder as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The term "must" indicates a requirement, while terms such as "should," "recommends," and "expects" indicate a recommended practice.

Each AER requirement that is unique to this directive is numbered.

Information on compliance and enforcement can be found on the AER website.

1.3 What's New in This Edition

Requirements in the following sections have been clarified or adjusted:

- Section 2, "External Corrosion Prevention Coatings Under Pipeline Insulation"
- Section 5, "Pipeline Pressure Testing Using Liquid Test Media Other Than Fresh Water"
- Section 6, "Pipeline Pressure Testing Using Gaseous Test Media"
- Section 7, "Temporary Surface Pipelines for Well Testing or Bypass"
- Section 8, "Temporary Surface Pipelines for Water Conveyance"
- Section 9, "Elevated-Temperature Pipelines"

1.4 How to Use This Directive

This directive refers to specific clauses of *CSA Z662* and sections of the *Pipeline Rules*. Future amendments to either document may result in those references changing. The reader is advised that, in such cases, the applicable succeeding clause or section applies.

Appendix 2 provides an interpretation of the relationship between various regulatory instruments and industry standards concerning pipeline design.

All forms referenced in this directive are available in OneStop.

Questions regarding this directive can be sent by email to PipelineOperations@aer.ca.

2 External Corrosion Prevention Coatings Under Pipeline Insulation

2.1 Corrosion Under Pipeline Insulation

Clause 9 of *CSA Z662* requires an external **corrosion prevention coating** for steel pipelines that are buried, submerged, or exposed to the environment. Corrosion under insulation is a risk factor for all insulated pipelines. Corrosion under insulation can occur on pipelines with high temperatures due to water ingress when they are not in service or when trapped water cannot escape from water-saturated insulation. Stress-corrosion cracking concerns have been identified on insulated pipelines operating with high temperatures due to water ingress or improper insulation material.

2.2 Insulated Pipeline Corrosion Management

Common insulation systems are generally not considered effective corrosion prevention coatings and may increase the overall operational risk of any buried, submerged, or surface pipeline if corrosion is not proactively managed.

1) Unless otherwise exempted by the AER, an applicant applying for a licence for a new insulated pipeline must demonstrate that an effective corrosion prevention coating will be applied as outlined in clause 9 of *CSA Z662*.

2) Unless otherwise exempted by the AER, licensees of new insulated pipelines or licensees engaging in work that modifies an insulated pipeline must ensure that an effective corrosion prevention coating is applied as outlined in clause 9 of *CSA Z662*.

The high operating temperature of some insulated pipelines may exceed the operating range of some corrosion prevention coatings, and cases might occur where a corrosion prevention coating is not appropriate. Applicants may request an exemption from the AER to use **alternative corrosion prevention systems.**

3) To request an exemption from requirement 1 or 2, a licensee must submit the following to the AER at pipelineoperations@aer.ca:

   a) An engineering assessment that demonstrates to the satisfaction of the AER that the insulation and the alternate corrosion prevention system will provide effective long-term corrosion control.

b) A description of the methods and actions in the integrity management program used to monitor for corrosion or cracking under insulation and respond to any concerns.

c) The pipeline integrity management program for the pipeline must include measures for monitoring potential stress-corrosion cracking that may occur under wet insulation.

For more information on corrosion control for steel pipelines, see the following:

- *Bulletin 2021-36, Stress-Corrosion Cracking on Insulated High-Temperature Pipelines*
- *CSA Z662: Oil and gas pipeline systems*, clause 14
- *CSA Z245.22: Plant-applied external polyurethane foam insulation coating for steel pipe*

2.3 Exempted Pipelines

Insulated elevated-temperature pipelines registered with ABSA in accordance with section 9 of this directive must have had their design reviewed by ABSA to meet ABSA requirements. As such, requirement 1 does not apply to ABSA design-registered elevated-temperature pipelines. The AER recommends that licensees consider the potential for corrosion under insulation and stress-corrosion cracking in relation to insulated elevated-temperature pipelines.

3 High-Performance High-Density Polyethylene Pipe in Oil and Gas Service

The previous edition of *Directive 077* included a process for using high-performance bimodal HDPE pipe in oil and gas service. This type of pipe required design using ISO standards rather than the more familiar American Society for Testing and Materials (ASTM) design standards adopted by *CSA Z662*. The ASTM standards have since been revised to include this class of HDPE material.

Changes to clause 13.3 of *CSA Z662* now recognize the ASTM changes and allow for the use of higher-performance polyethylene pipe designated as type 4710. Because this change serves the industry's needs, the section on ISO design has been removed from *Directive 077*. Amendments or additions to existing licences of HDPE pipe installed using ISO methodology are still permissible.

4 Overpressure Protection for Pipelines Connected to Artificial Lift Equipment

Unless otherwise authorized by the AER, clause 4.18 of *CSA Z662* and section 31 of the *Pipeline Rules* require both pressure control and overpressure protection systems for pipelines where a source may overpressure the pipeline.

This section describes acceptable variations to the requirements for overpressure protection for pipelines connected to artificial lift equipment (i.e., any method or device that enhances production flow from the well). The accepted variations apply only to pipelines connected to artificial lift equipment. All other pipelines must follow the requirements of *CSA Z662*.

4) Where artificial lift equipment is capable of supplying pressure exceeding the pipeline's **maximum operating pressure** (MOP), the licensee must implement one of the following options:

    a) Option 1:

        i) Use two independently operated overpressure protection devices designed to stop the pressure from exceeding the licensed MOP.

        ii) Ensure the first overpressure protection device will independently stop the pressure from exceeding the licensed MOP, and the second overpressure protection device will independently stop the pressure from exceeding the licensed MOP by more than 10% or 35 kilopascals (kPa), whichever is greater, as described in *CSA Z662*.

        iii) Inspect, assess, and test the devices in accordance with the requirements of *CSA Z662* or, optionally, in accordance with a schedule developed and fully documented under the licensee's integrity management program.

    b) Option 2:

        i) Use a single overpressure protection device designed to stop the pressure from exceeding the licensed MOP.

        ii) Ensure a **competent individual** conducts a monthly inspection and service test on the single overpressure protection device.

        iii) Have a certified instrumentation technician or equivalent inspect the single overpressure protection device annually (but not more than 18 months between inspections) to confirm the monthly inspections, assessments, and service testing were correctly conducted and that the device is not **defective or inoperative**.

5) If any overpressure protection device is found to be defective or inoperative, the licensee must stop operations of the pipeline and repair or replace the device before continuing with operations.

6) For all overpressure protection devices, the licensee must

    a) maintain logs of inspection, assessment, and tests in accordance with its integrity management program and this requirement, and

    b) provide those logs to the AER on request.

At locations where the pipeline licensee and well licensee are different, if not defined by an agreement between the licensees, the pipeline licensee is responsible for ensuring the protection of the pipeline from artificial lift equipment.

5 Pipeline Pressure Testing Using Liquid Test Media Other Than Fresh Water

Hydrostatic pressure testing is used to qualify new pipeline construction or requalify an existing pipeline by confirming the pipeline has the necessary strength and has no leaks.

Fresh water is the preferred medium for pressure testing pipelines due to its benign effects on the environment should a leak occur. A freezing-point depressant, such as methanol or glycol, may be added to prevent the water from freezing when temperatures are below freezing.

The use of normally transported pipeline fluids may be acceptable for pipeline pressure testing in certain situations. It is recommended that these fluids should only be used when technical considerations make the use of fresh water as the test media impractical or when the test pressure is less than the MOP and is being monitored for a period to confirm leak tightness.

In addition to the requirements of this section, the licensee must apply the requirements for pressure testing set out in *CSA Z662* and Part 3 of the *Pipeline Rules*.

7) Before starting the pressure test, the licensee must notify the AER by submitting via OneStop a completed Pipeline Pressure Testing Using Liquid Test Media Other Than Fresh Water form at least 48 hours in advance.

    a) A copy of the completed form must be present at the test location during pressure testing.

    b) The completed form must be kept in accordance with the requirements of the licensee's safety and loss management system and integrity management program.

8) Before starting the pressure test, the licensee must prepare a contingency plan as required under *CSA Z662* to protect the environment in the event of a release or spill of the liquid test medium. The licensee must provide a copy of this contingency plan to the AER on request.

9) If the pressure test meets any of the following criteria, the licensee must stage the contingency plan, including any required equipment, on site and be prepared to respond to any release or spill of the liquid test medium:

    a) The volume of the test section will exceed 500 cubic metres (m^3).

    b) The hoop stress level during the pressure test will exceed 100% specified minimum yield strength (SMYS).

    c) The pipeline will cross or pass within 100 metres (m) of flowing water at the time of the pressure test.

10) If the pressure test meets any of the criteria from requirement 9, and any of those variables change, even slightly (e.g., the hoop stress increases or decreases a percentage point), the licensee must notify the AER via OneStop of the change by resubmitting the Pipeline Pressure

Testing Using Liquid Test Media Other than Fresh Water form via OneStop as soon as possible.

6 Pipeline Pressure Testing Using Gaseous Test Media

Hydrostatic pressure testing is used to qualify new pipeline construction or requalify an existing pipeline by confirming the pipeline has the necessary strength and is leak tight.

Fresh water is the preferred medium for pressure testing pipelines due to its incompressibility and benign effects on the environment should a leak occur. In specific circumstances, it may be necessary or advantageous to use air or other gaseous media as an alternative to water.

However, the compressibility of gaseous test media can result in difficulties in interpreting the leak tightness of a pipeline. Minor leaks may be masked by the compressibility of the test medium. For this reason, limitations are placed on the volume of test sections, and test durations are extended to give more time for a leak to become apparent. It may be possible to conduct gaseous media tests on larger test volumes as described in the following requirements. Accordingly, the licensee must first complete an engineering assessment that evaluates the compressibility of the media and the sensitivity of the test to establish a satisfactory test duration that would enable the successful determination of leak tightness.

Pressure tests using gaseous media present a higher risk to personnel and property near the pipeline. A test failure may result in violent releases of stored energy. For this reason, additional safety precautions must be used. Licensees considering the use of gaseous media pressure tests must follow the pertinent parts of *CSA Z662* and Part 3 of the *Pipeline Rules*. Gaseous media testing is strongly discouraged in densely populated areas or for testing pipelines that have been in service.

Before pressure testing existing piping to a pressure that is significantly higher than established normal operating pressure, including when testing using gaseous test media, an engineering assessment must be conducted in accordance with clause 10 of CSA Z662.

The conditions described below must be met to use gaseous test media, including limitations on the pipeline pressure and allowable stresses.

AER *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* places restrictions on the amount of natural gas to be flared or vented and imposes public notification guidelines for flaring of gas used as a test medium.

11) The licensee must notify the AER by submitting via OneStop a completed Pipeline Pressure Testing Using Gaseous Test Media form at least 48 hours before the start of a gaseous media pressure test.

    The AER may stop or prohibit a gaseous media pressure test if it believes the test might be inappropriate or constitute a safety hazard to personnel or the public. Testing may proceed once any concerns have been satisfactorily resolved.

The AER recommends that licensees limit test segments to volumes of 125 m^3 or less to enable successful leak detection when tested over a 24-hour period.

12) Before conducting a gaseous media test using volumes greater than 125 m^3, the licensee must include in their AER notification an engineering assessment that considers the test volume and demonstrates that the proposed testing procedure and duration are safe and will successfully detect a small leak.

13) For test volumes greater than 125 m^3, licensees must follow note 2 of clause 8.7.5.3 of *CSA Z662* and consider the effect of gas compressibility when determining the length of the test section and the duration of the test needed for successful detection of small leaks.

Table 1 shows the approximate pipeline lengths for steel pipelines of different diameters that result in volumes of 125 m^3. Licensees should use the actual measurements of the pipeline to calculate the volume accurately.

Table 1. Steel pipe test section lengths for volumes of 125 m^3

Pipeline diameter (nominal; mm)	60.3	88.9	114.3	168.3	219.1	273.1	323.9
Test section length (km)	57.8	23.4	14.1	6.3	3.7	2.3	1.7

14) The licensee must use high-resolution (i.e., better than 1%) pressure measurement instruments to detect minor pressure losses while testing.

15) The licensee must maintain a hold period sufficient to allow the pipeline to fully stabilize after pressurization before beginning the 24-hour test period.

16) The licensee must continuously monitor the pipeline's ambient temperature and internal test section temperature during the test to allow reconciliation against pressure changes.

The licensee may consider additional techniques to assist in leak detection, such as using an odorant, gas detectors, ultrasonic leak detectors, thermography, and trained animal detectors.

7 Temporary Surface Pipelines for Well Testing or Bypass

This section addresses the process for obtaining approval for a TSP for well testing or as a bypass as defined in the *Pipeline Rules*. Such approvals are valid for 21 consecutive days beginning the first day of the temporary flow (i.e., in service) and expiring at midnight of the 21st day. Temporary interruptions of service will not extend the 21-day period.

The AER may consider an extension beyond 21 days in extenuating circumstances.

Use of a surface pipeline as a production pipeline is not allowed except where the licensee applies under *Directive 056: Energy Development Applications and Schedules* for a surface pipeline, which may be licensed for up to one year.

See section 8 of this directive for the requirements for TSPs conveying water.

17) A duty holder intending to install and operate a TSP for well testing or bypass must obtain written AER approval before the construction or deployment of the pipeline.

18) To request approval from the AER, the duty holder must

    a) complete the Temporary Surface Pipeline for Well Testing or Bypass form and submit the form to the AER via OneStop and,

    b) if requested, submit to the AER information that supports the statements made in the form.

    If a duty holder indicates “no” to any item on the form, the request will require further technical evaluation. Duty holders should include with the form an explanation for any “no” response and supporting evidence well before the intended pipeline construction date to ensure the AER has sufficient time to evaluate the application.

    Upon completing any technical evaluation, the AER will make a decision concerning the request.

19) The duty holder must obtain documented consent from landowners, occupants, or entities in care and control of the lands on which the TSP will be installed and provide those documents to the AER on request. If this requirement cannot be met, the TSP for well testing or bypass approval process described in this directive cannot be used, and a *Directive 056* pipeline licence must be obtained instead.

20) The duty holder must keep a copy of the form and the AER’s consent at the pipeline location during installation through to remediation and reclamation of the pipeline right-of-way.

21) A duty holder that has installed a TSP under the 21-day approval process must

    a) remove it within 30 calendar days or per approval conditions of the expiry of the approval and

b) remediate and reclaim the pipeline right-of-way within 60 calendar days of the expiry of the approval.

If necessary, contact the AER by email at PipelineOperations@aer.ca to request more time to remediate and reclaim the pipeline right-of-way.

Duty holders proposing to use a TSP for well testing or bypass must comply with the requirements in sections 25 and 30(2)(4) of the *Pipeline Rules* for surface pipelines, despite these TSPs not being licensed.

Duty holders proposing to use a TSP for well testing or bypass must comply with the requirements of *CSA Z662*, including the sour service requirements specified in clause 16.

8 Temporary Surface Pipelines for Water Conveyance

This section addresses the authorization process and technical requirements for TSPs for water conveyance (TSPW) as defined in the *Pipeline Rules*, which are used to convey water to support energy development (e.g., well drilling, well completion, hydrostatic testing). The goals of the requirements are to ensure that no water conveyed through a TSPW is inadvertently released and the risk to public safety and the environment remains low for all uses of TSPWs.

A TSPW may

- convey only water or water-based liquids (see table 1 for water groups),
- operate at a pressure of no more than 3500 kPa,
- be deployed for a defined period not exceeding 12 months (unless approved for an extension of up to 12 months), and
- be mostly on the ground surface; however, portions of the TSPW may be elevated, buried, or otherwise covered (e.g., for crossing waters or roadways).

The regulatory requirements for conveying water through TSPWs are proportional to their potential effect on public safety and the environment. Table 1 lists the permissible water groups for a TSPW.

Mixtures of water from different groups (in any proportion) are classified as the highest-numbered group within the mix. Mixing of water must comply with applicable Government of Alberta policies and regulations.

Users of TSPWs should be familiar with and implement industry best practices for water transfer systems where they go beyond the below requirements, such as those presented in Energy Safety Canada's Industry Recommended Practices documents and *American Petroleum Institute's (API) Recommended Practice 15WT: Operations for Layflat Hose in Oilfield Water Applications*.

22) If a mixture of water groups is to be conveyed, the duty holder must know the chemical composition of the mixture.

Water containing constituents at levels that could be an immediate human health hazard if released is prohibited from being conveyed through a TSPW, including water with extreme pH (i.e., ≤2 or ≥11.5) or water with unsafe levels of hydrogen sulphide (H_2S), naturally occurring radioactive materials, or flammable or explosive constituents.

Table 2. Water groups for TSPW conveyance

Water group	Description	Criteria
1	Water with a negligible effect on the environment or public safety if released.	Group 1 water comprises **nonsaline water** (both surface and groundwater) that meets the following criteria: • chloride content of no more than 500 milligrams per litre • electrical conductivity of no more than 2.0 decisiemens per metre • pH between 6.0 and 9.0 • no hydrocarbon sheen • does not contain municipal wastewater, water affected by an industrial process, or produced or process water from an oil or gas activity • has not had any chemical added before conveyance in the TSPW
2	Water that may have an environmental effect if released. The effect is generally easily and quickly reversible, and the risk to public safety is negligible.	Group 2 water includes treated drinking water, final treated municipal or industrial effluent, and nonsaline water (both surface and groundwater) that does not meet the criteria for group 1 or 3 water.
3	Water that will have an environmental effect if released. The effect is not generally easily or quickly reversible, but the risk to public safety is low.	Group 3 water includes saline groundwater, partially or untreated municipal or industrial wastewater, produced water, fracturing flowback water, liquid oilfield wastewater, and other water that does not meet the criteria for group 1 or 2 water.

8.1 Approval and Notification Process

In accordance with sections 7(3)(b) and 7(4) of the *Pipeline Rules*, TSPWs are exempt from requiring a pipeline licence; however, in all cases, duty holders must notify the AER before any water can be conveyed. In addition, if conveying group 2 and 3 water, the duty holder must receive approval from the AER before any water can be conveyed (see below requirements).

23) Before submitting a notification for group 1 water or a request for approval for group 2 or 3 water, the duty holder must have documented consent from all landowners (including municipalities) and occupants on whose property the TSPW will be deployed in accordance with requirement 37.

24) A duty holder must have prior approval from the AER to convey water from a higher-numbered group through a TSPW authorized for a lower-numbered group. Use the TSPW Group 2/3 Water Approval Request form to request this change.

The TSPW duty holder may consent, through a private agreement, to share the TSPW with another party. The TSPW must remain in compliance with the existing approval. The original duty holder remains responsible for the TSPW and the required data collection, incident response, and end-of-operation obligations.

25) If another duty holder seeks to assume responsibility for an existing deployed TSPW, they must follow the approval or notification processes appropriate to the water group as outlined below. In these cases, to ensure the deployment duration is not exceeded or changed, the duration of deployment will be measured from the date the original duty holder deployed the TSPW. The last duty holder for the TSPW will be responsible for decommissioning the TSPW (section 8.5.8.1) and site restoration (section 8.5.8.2).

8.1.1 Group 1 TSPW Deployment Notification

26) A TSPW conveying group 1 water does not require AER approval. However, before starting any field activities related to deploying and operating the TSPW, the duty holder must notify the AER by submitting via OneStop a completed TSPW Group 1 Water Notice of Deployment form at least 24 hours in advance (but not more than 14 **business days**).

8.1.2 Group 2 and 3 TSPW Approval

27) The duty holder must submit to the AER via OneStop a completed TSPW Group 2/3 Water Approval Request form.

28) The duty holder must receive AER approval for TSPWs conveying group 2 or 3 water and notify the AER (section 8.1.3) before starting any field activities related to deploying and operating the TSPW.

29) Any request to deviate from the technical requirements contained in section 8.5 must be approved by the AER. The duty holder must identify and describe any requested deviations in the approval request submitted and provide any associated documentation (e.g., material specifications) and a justification for the requested deviation and associated mitigations.

8.1.3 Group 2 and 3 TSPW Deployment Notification

30) After receiving approval from the AER, but before starting any field activities related to deploying and operating the TSPW, the duty holder must notify the AER by submitting via OneStop a completed TSPW Group 2/3 Water Notice of Deployment form at least 24 hours in advance (but not more than 14 business days). If a group 2 or 3 approval has been granted and

the notified deployment dates have changed, submit a new deployment notification form referencing the most recent approval ID.

8.1.4 TSPW Route Map

31) All TSPW notifications or approval requests must include a route map at an appropriate scale.

    Various digital formats for the map are acceptable (e.g., JPEG, PDF, PNG, TIF).

32) The route map must include the following:

    a) the entire route of the TSPW and its start and end points, including all segments

    b) planned location of TSPW equipment (e.g., water storage areas, pumps, valves, shutoff devices, spill response materials)

    c) location of all AER-regulated sites connected to the TSPW, with associated authorization identifiers

    d) points where the TSPW crosses roads, water bodies, trails, access points, etc., including culverts and dry **ephemeral water bodies** that the TSPW will pass through (roadside ditches do not need to be indicated)

    e) water bodies (including dry ephemeral water bodies), water wells, and **sensitive receptors** within 50 m for group 1 and 2 TSPWs or within 100 m for group 3 TSPWs.

    f) steep slopes, draws, and ravines along the TSPW route that may increase water movement in the event of a release

    g) land cover types (e.g., forest, pasture, agriculture, recreation) adjacent to the route

Minor changes to a route or equipment placement do not require an amendment submission. However, significant alterations such as taking a different road, crossing a different landowner's property or a new public land disposition, or crossing a different water body require an amendment request (all water groups) and approval request (group 2 and 3) to proceed.

8.2 Extension Requests and Amendments

The maximum 12-month term of a TSPW may be extended only once for up to 12 additional months.

33) The duty holder must submit a request via OneStop to amend the removal date by submitting a completed TSPW Group 1/2/3 Water Amendment form at least seven business days before the expiry of the original notification (for group 1 water) or the original approval (for group 2 or 3 water).

34) An extension request must include

a) the original notification reference number (for group 1 water TSPW) or approval number (for group 2 or 3 water TSPW);

b) confirmation that land access permissions remain valid;

c) confirmation that the operation remains the same as originally notified (for group 1 water TSPW), approved (for group 2 and 3 water TSPW), or amended (except for conveying a lower-numbered group of water, which is permissible); and

d) an explanation of why the extension is needed.

35) The duty holder must notify the AER via OneStop of changes in routing (excluding minor changes as outlined in 8.1.4), use of different materials (for group 2 and 3 TSPWs), deviations from commissioning procedures, changed operating pressure (for group 2 and 3 TSPWs), or changes to the surveillance plan (for group 2 and 3 TSPWs) and also submit via OneStop a completed TSPW Group 1/2/3 Water Amendment form before starting operations or within 48 hours if changes are made after the start of operations.

36) If for any reason the TSPW is not deployed, the duty holder must inform the AER by submitting via OneStop a completed TSPW Operations Summary form no later than 30 calendar days after the originally planned end of operations.

8.3 Consent and Notification

37) The duty holder must obtain documented consent from the landowners, occupants, or entities in care and control of the lands on which the TSPW will be installed and provide those documents to the AER on request.

38) The duty holder must notify landowners, occupants, or entities in care and control of land adjacent to the TSPW if it might hinder access to those lands.

8.4 Documentation Requirements

39) The duty holder must keep a copy of the TSPW deployment notification submission (for group 1 water) or TSPW approval and deployment notification (for group 2 or 3 water) on site during deployment through to decommissioning and restoration of the TSPW route and provide it to the AER on request.

8.5 Technical Requirements

8.5.1 Route Selection and TSPW Placement

The goal is to install TSPWs in locations that pose minimal risk to public safety and the environment during all phases of use, particularly in the event of a release of conveyed water.

The TSPW's route should minimize the risk of environmental damage, including threats to the quality of soils, surface water, groundwater, and the health of humans, animals, and plants during the deployment, operation, and decommissioning of the TSPW. Routing of TSPWs is recommended to avoid crossing water bodies as defined in *Directive 056*.

A TSPW and its associated equipment should be as far as practicable from water bodies, water wells, and sensitive receptors. Moreover, the statement applies specifically to a TSPW and the associated equipment used to operate it (e.g., booster pumps), not the equipment like pumps needed to access or divert water from the source.

The AER expects duty holders will minimize surface disturbance when installing and operating a TSPW.

40) Where a TSPW route cannot avoid crossing a water body, the duty holder must ensure that the TSPW meets the following requirements:

    a) The TSPW is elevated above the water body and areas where water can accumulate so it is never submerged (fully or partially) to ensure effective, continuous detection of leaks. Existing bridges, with permission from the bridge operator or owner, are preferred crossing points. Other supports may be acceptable if they allow for effective leak detection and meet all regulatory requirements (including those associated with navigation). Such supported water crossings must be clearly marked so as to be easily visible to users of the water body. Extra consideration of TSPW placement may be necessary for operations planned to occur during spring run-off conditions when water levels can fluctuate significantly.

    b) If conveying group 2 water, there must be no pipe connections within 10 m of the water body. If this is not possible, the pipe connections must have devices, equipment, or containment to collect and contain any leakage or redirect it to an area where it will be contained.

    c) If conveying group 3 water, secondary containment must be placed across and extending 10 m on each side of the water body to redirect any leakage away from the water body to an area where it will be contained.

TSPWs may be placed across frozen water bodies if they are reasonably expected to remain frozen during the entire duration of deployment and end-of-operations activities (with ice of sufficient thickness to safely support the water-filled TSPW and the personnel and equipment needed to operate it; see section 8.5.8 for related requirements). TSPWs may not be placed directly on ice or snow covering the water body; requirement 40 is applicable to ice crossings. TSPWs should be clearly marked so as to be visible to any users of the frozen water body.

41) TSPWs may cross ephemeral water bodies that are reasonably expected to remain dry for the entire duration of deployment. If the ephemeral water body accumulates water during conveyance operations, actions to comply with requirement 40(a) must be implemented within two days. If transmitting group 3 water, conveyance operations must cease until the TSPW is no longer submerged (fully or partially). Enhanced surveillance and leak detection activities are necessary until the TSPW is no longer submerged (fully or partially; see section 8.5.6 for related requirements).

TSPWs may be deployed in man-made drainage ditches that remain dry except during and immediately after precipitation events. If passing through drainage culverts, adequate drainage of precipitation must be maintained. Duty holders are reminded that roadway ditches are often direct pathways to surface water bodies; appropriate surveillance and placement of spill mitigation equipment is an important consideration in designing the surveillance program for TSPWs routed in ditches.

Some culverts are designed to maintain connectivity of waterbodies and allow fish passage past roads, railways etc. These culverts are part of a waterbody, and therefore requirement 40 remains applicable to TSPWs passing through these culverts.

42) Unless the landowners, occupants, or entities in care and control of the land previously agree, the duty holder must deploy a TSPW so as not to materially impair the following:

   a) drainage (e.g., through drains, ditches, culverts, overland)

   b) vehicle safety (road and off-highway vehicles and watercrafts)

   c) road and right-of-way maintenance (e.g., rutting that impairs vehicle safety, vegetation control, snow removal)

   d) animal (domestic or wild) movement, feeding, or breeding

43) The duty holder must take appropriate measures to maintain access to land adjacent to the TSPW and protect the TSPW from damage or, if necessary, provide an alternative access point acceptable to the landowners, occupants, or entities in care and control of the land.

44) The duty holder must operate the TSPW in a manner that protects the public and the environment and in accordance with all applicable legislation.

The duty holder must comply with all applicable provisions as set out in section 2(4) of the *Pipeline Rules*.

8.5.2 Materials

The goal is to construct TSPWs using materials that are fit for the intended purpose and minimize the risk to public safety and the environment from materials-related failures.

45) The duty holder must construct the TSPW using materials (e.g., pipe, gaskets, seals, pipe connections) compatible with the water conveyed (e.g., chemical constituents) and the operating conditions (e.g., weather, temperature, duration, MOP).

46) All TSPW materials and associated equipment must be installed, operated, maintained, and stored in accordance with the manufacturer's specifications and limitations.

47) All pipe connections must be designed to prevent unintentional separation (including decoupling, vibration, or movement) or include other measures to prevent separation.

48) In locations where the TSPW may be easily accessible to the public (e.g., alongside roads/trails, across agricultural land, etc.), secondary restraint devices to prevent whipping in the event of TSPW separation are required, unless connections are flanged or heat-fused. Restraints should be designed in collaboration with the TSPW manufacturer, and a risk-based approach should be implemented to identify appropriate locations where interactions with the public could occur.

8.5.3 Deployment

The goal is to deploy TSPWs and maintain the integrity of the materials while minimizing ground disturbance and having appropriate spill control and containment equipment in place to protect public safety and the environment in the event of a release.

49) The duty holder must have a documented deployment procedure appropriate for the TSPW materials, the water group, and the quality of the water for conveyance that includes consideration of the following:

    a) ground surface preparation to protect the TSPW from possible damage

    b) material handling and installation procedures

    c) pipe connection instructions

    d) measures to minimize TSPW movement during operations

    e) measures to protect the TSPW when deployed

    f) deployment cleanup and route maintenance guidance (e.g., repair of ruts, vegetation control, etc.)

    Duty holders should include any additional information deemed necessary for successful deployment in their procedure.

50) The duty holder must keep a paper or electronic copy of the deployment procedure on site and provide it to the AER on request.

51) Unless authorized by the AER, devices or containers to collect and contain potential leakage must be used at pipe connections when conveying group 3 water within 100 m of water bodies, water wells, or sensitive receptors.

52) **Pumping units** within 100 m of water bodies or water wells must be equipped with devices or containers to collect and contain potential leakage of conveyed water, fuel, or lubricants from the pumping unit.

53) Unless authorized by the AER, a TSPW conveying group 2 or 3 water near water bodies, water wells, or sensitive receptors (within 50 m for group 2 and within 100 m for group 3) must be equipped with flow-stopping devices, such as valves, clamps, or crimping devices, placed within 100 m of the water body, water well, or sensitive receptor to shut off the flow and isolate portions of the TSPW to limit the volume of water released in the event of a leak. Where a TSPW parallels a water body within the distances given above, additional flow-stopping devices must be a maximum of 500 m apart along the portion of the TSPW that parallels the water body and within 100 m of where the TSPW nears and moves away from the water body.

54) Where the AER is satisfied that an effective barrier to water flow exists between the TSPW and a water body, water well, or sensitive receptor, requirements 51, 52, and 53 do not apply. Using the TSPW Group 2/3 Water Approval Request form, the duty holder must describe how existing barriers will prevent water flow from reaching water bodies, water wells, or sensitive receptors and indicate the barriers on the route map.

    For example, leakage collection devices at pipe connections (requirement 51) or at pumping units (requirement 52) and flow-stopping devices (requirement 53) may not be required for a TSPW deployed in a roadside ditch with a water body on the opposite side of the road, with no crossing culverts.

55) Pumping units for group 2 and 3 water TSPWs must be equipped with automated shutdown devices set to quickly deactivate pumping when significant deviations in pressure are identified while minimizing nuisance trips and false alarms.

56) The duty holder of a TSPW must install and maintain clearly visible and legible signage at appropriate locations along the TSPW route (e.g., water crossings, road/rail crossings, and at ancillary equipment [unless nearby signage is visible from these locations]) that displays the following:

    a) company name and emergency phone number for the pipeline operator (if not the duty holder)

b) identification that the TSPW is a “Pressurized Water Pipeline” and the contents are “not potable” (further identification of the contents is optional)

c) applicable warnings (e.g., hazardous contents)

57) The duty holder must maintain a log of deployment activities conducted, including photos or videos of water crossings, and provide it to the AER on request.

8.5.4 Commissioning

The goal is to verify the integrity of the TSPW and its proper construction and deployment to minimize the risk of preventable leaks from material or installation issues.

58) The duty holder must have a documented commissioning procedure appropriate for the TSPW materials, the water group, and the quality of the water for conveyance that includes the following:

a) A visual inspection of the entire TSPW, all pipe connections, and associated equipment after the TSPW is deployed but before water is introduced.

Air testing to a pressure not exceeding 210 kPa may be used as a screening method to identify any issues with pipeline integrity. Appropriate safety measures should be taken when using pressurized air.

b) An integrity test to verify water containment:

i) For group 1 and 2 water TSPWs, the integrity test must include the following:

- A visual inspection during the initial fill of the TSPW (using group 1 or 2 water) to detect leaks as the leading edge of the water advances through the TSPW. Resolve any leaks before going to the next step.
- Initiate the surveillance program immediately upon reaching operating pressure and start active conveyance operation.

ii) For group 3 TSPWs, the integrity test must include the following:

- A visual inspection during the initial fill of the TSPW (using group 1 or 2 water) to detect leaks as the leading edge of the water advances through the TSPW. Resolve any leaks before going to the next step.
- A visual inspection of the entire TSPW immediately after it reaches operating pressure (with group 1 or 2 water). Water may continue to flow or be held. Resolve any leaks before going to the next step.
- Initiate the surveillance program, introduce group 3 water, and start active conveyance operation.

c) Verification that all monitoring equipment and systems function properly.

Duty holders should include any additional information deemed necessary for successful commissioning in their procedure.

59) The duty holder must successfully complete the commissioning procedures before putting the TSPW into operation. Commissioning is successful when visual inspection and integrity testing confirms no leaks, and monitoring equipment and systems have been verified to function properly.

60) The duty holder must keep a paper or electronic copy of the commissioning procedure on site and provide it to the AER on request.

61) The duty holder must maintain a log of commissioning activities carried out and provide it to the AER on request.

The AER recommends that the duty holder follow the manufacturer's commissioning procedure if it is more rigorous than the directive.

8.5.5 Operations

The goal is to operate TSPWs consistent with material specifications and parameters and minimize the risk to public safety and the environment during operations.

62) The duty holder must have a documented operating procedure appropriate for the TSPW materials, the water group, and the quality of the water for conveyance that includes the following:

a) identification of the operating limits (e.g., pressure, flow rate, temperature, substance) given in the manufacturer's specifications and the planned MOP

b) instructions for safely operating pumping and monitoring equipment

c) directions for conducting the surveillance program (see section 8.5.6)

d) directions for implementing incident response (see section 8.5.7)

e) directions for emptying and purging the TSPW

f) considerations for operating the TSPW under anticipated weather conditions

Duty holders should include any additional information deemed necessary for successful operation in their procedure.

63) The duty holder must keep a paper or electronic copy of the operating procedure on site and provide it to the AER on request.

64) An operations supervisor must be on site while the TSPW is pressurized.

65) Chemicals or additives introduced to group 2 or 3 water must be identified on the TSPW Group 2/3 Water Approval Request form.

66) When the active transfer of water through the TSPW is suspended for more than 24 hours, pressure must be relieved from the system.

67) When a TSPW is out of service for more than seven days, it must be drained.

68) If a TSPW conveying group 2 or 3 water has been drained, a thorough visual inspection of the pipeline and pipe connections must be completed immediately after refilling and repressurizing it.

69) The duty holder must maintain a log of operational activities (e.g., pumping times, suspension and restarts, maintenance, repairs) carried out and provide it to the AER on request.

8.5.6 Operations Surveillance

The goal is to monitor TSPW operations to identify and correct risks as soon as possible and avoid or minimize potential effects on public safety and the environment. Effective surveillance supports continuous improvement in the various aspects of TSPW use, from planning to decommissioning.

70) The duty holder must have a documented surveillance program appropriate for the TSPW materials, the water group, and the quality of the water for conveyance that considers the following hazards:

    a) water releases (e.g., drips, sprays, breaches, breaks)

    b) external damage that may indicate or lead to future integrity concerns (e.g., blisters, colour or opacity change, bulges, cuts, scratches, gouges, kinks, folds, third-party interference)

    c) internal damage (e.g., corrosion of couplings and fittings, abrasion)

    d) internal blockage (e.g., ice, slush, debris)

    e) blocked drainage, debris accumulation, flooding, and ponded water along the TSPW route

    f) TSPW movement (e.g., excessive rolling or snaking)

    g) effects on vegetation

    h) ground erosion

    i) any other hazard identified as part of the duty holder’s hazard identification process

    Regarding requirement (c) above, the duty holder may perform this surveillance through spot checks or by following the manufacturer’s guidance.

    Duty holders should include any additional information deemed necessary in their program for successful surveillance. The surveillance program should consider aspects related to worker

safety, such as traffic, wildlife, working alone, time of day, weather conditions, wildfires/smoke, and other factors. Operations may need to be adjusted to ensure surveillance can be completed safely.

71) The surveillance program for group 2 and 3 water must be submitted with the TSPW Group 2/3 Water Approval Request form.

72) The duty holder must keep a paper or electronic copy of the surveillance program on site and provide it to the AER on request.

73) The surveillance program must be active at all times the TSPW is pressurized.

74) Visual observation and monitoring of flow rate and pressure must be part of the surveillance program and scheduled at a frequency sufficient for the timely identification of potential hazards or incidents. Planned surveillance frequency is to be clearly identified in the surveillance program.

75) Pressure monitoring of the TSPW must be sufficiently sensitive to indicate the presence of a leak requiring mitigation. Such pressure anomalies must be promptly investigated.

76) Enhanced surveillance (i.e., more frequent visual inspection) is required for portions of a TSPW

   a) crossing water bodies (including wet ephemeral water bodies and draws and flowing ditches and drains) and

   b) within 50 m (for group 1 and 2 water TSPWs) or 100 m (for group 3 water TSPWs) of a sensitive receptor.

77) If surveillance activities identify the occurrence of a hazard identified in requirement 70, the duty holder must investigate and remedy it (if necessary) in accordance with section 8.5.7.

78) The duty holder must maintain a log of the surveillance activities carried out and provide it to the AER on request.

8.5.7 Incident Response and Reporting

For TSPWs, an incident is the occurrence of any hazard listed in requirement 70. The incident response and reporting requirements do not supersede or replace the *Environmental Protection and Enhancement Act*, *Remediation Regulation*, *Conservation and Reclamation Regulation*, *Directive 071: Emergency Preparedness and Response,* or other relevant requirements.

79) TSPW duty holders must follow the requirements for spill preparedness and response in sections 8 and 9 of *Directive 071*.

80) The duty holder must keep a paper or electronic copy of the spill response plan on site and provide it to the AER on request.

Duty holders are reminded that depending on the group of water being conveyed, provisions concerning release response under the *Environmental Protection and Enhancement Act* may apply, including requirements for remedial work and reporting. For more information, see the AER's release reporting webpage.

The Energy and Environmental Emergency 24-Hour Response Line number is 1-800-222-6514.

81) The duty holder of a group 2 or 3 TSPW must maintain a log of incidents, near misses, or identified hazards noted during operations and submit it to the AER at the end of operations (using the TSPW Operations Summary form) or upon request by the AER that includes the following information:

    a) location and time

    b) description of the incident and circumstances leading to its occurrence

    c) details of any action taken

    d) any outstanding follow-up measures

82) If an incident other than water release occurs, the duty holder must initiate incident response within the following timeframes unless other legislation or regulation takes precedence:

    a) For incidents related to TSPW damage or blockage (i.e., hazards in requirement 70(b)–(d)),

        i) respond as soon as possible for TSPWs conveying group 1 water and

        ii) immediately for TSPWs conveying group 2 or 3 water.

    b) For incidents related to drainage and debris (i.e., hazards in requirement 70(e)), respond immediately regardless of the water group being conveyed.

    c) For incidents related to TSPW movement, effects on vegetation, erosion, or other identified hazards (i.e., hazards in requirement 70(f)–(i)), respond immediately if a safety hazard is created or as soon as practicable if a safety hazard is not created.

8.5.8 End of Operations

The end of operations occurs when the duty holder no longer needs the TSPW for water conveyance or the expiry of the notification or approval or any extension granted, whichever occurs first.

83) If an AER suspension or abandonment order exists for any site connected to the TSPW, making continued use of the TSPW unfeasible, the duty holder must immediately start and complete the end-of-life obligations within the specified timeframes.

8.5.8.1 Decommissioning

84) At the end of operations, the duty holder must drain and purge all water in the TSPW within seven calendar days and manage the water in accordance with applicable regulations.

85) The duty holder must remove the TSPW and its associated equipment within one month of the end of operations or, if the TSPW is installed on ice, before the water body thaws. If conditions prevent removal within the specified timeframe, the duty holder must initiate removal as soon as conditions permit.

86) If removal is not possible within the specified timeframe (see requirement 85), the duty holder must inform the AER by submitting an extension request (see section 8.2). An extension for TSPW removal does not permit the duty holder to continue conveying water.

8.5.8.2 Site Restoration

87) Within two months of the end of operations, the duty holder must restore the TSPW route to predeployment conditions (or a condition otherwise agreed to with the landowners, occupants, or entities in care and control of the land). If conditions prevent site restoration within the specified timeframe, the duty holder must initiate and complete restoration as soon as conditions permit.

88) Such situations must be identified to the AER by submitting an extension request (see section 8.2). An extension for TSPW site restoration does not permit the duty holder to continue conveying water.

8.5.8.3 Closeout Reporting

89) The duty holder must submit a completed TSPW Operations Summary form within 30 calendar days of completing site restoration activities, including the following:

a) actual volume of water conveyed

b) dates of completion for TSPW operations, TSPW removal, and restoration of the TSPW route

c) a summary of any incidents (see requirement 81)

9 Elevated-Temperature Pipelines

9.1 Introduction

Pipelines used in the recovery of hydrocarbons from a reservoir or oil sands deposit are a “pipeline” and are licensed and regulated by the AER under the *Pipeline Act*.

In this directive, an "elevated-temperature pipeline" means any pipeline that meets any of the following criteria:

- steam distribution pipelines with a total internal volume greater than 0.5 m^3
- steam distribution pipelines with a design temperature above 120°C
- pipelines with a design temperature above 120°C that operate in multiple services, where one of those services is steam distribution
- pipelines with a design temperature above 230°C that are used for recovering produced fluids that include steam condensate from a reservoir

Based on the specified design parameters for the pipeline, the duty holder is responsible for determining if an appropriate elevated-temperature pipeline design is required (*CSA Z662* clause 14 or annex I).

Any registered design must be issued by ABSA and comply with ABSA requirements. The flowchart in appendix 3 of this directive further explains the applicability of AER-ABSA jurisdiction, where ABSA design registration is required or optionally chosen.

In Alberta, there is shared responsibility for licensing and design evaluation of pipelines distributing steam at design temperatures >120°C or recovering produced reservoir fluids at design temperatures >230°C. Where such pipelines relate to an oil or gas project under the jurisdiction of the AER, the AER is responsible for pipeline licensing. Through a memorandum of understanding with ABSA (the pressure equipment safety authority), ABSA is responsible for reviewing pipeline design, quality management, construction, pipeline integrity management program, and registering the design. Applicants must obtain design registration from ABSA before applying to the AER to construct the pipeline.

9.2 Exemptions

Temporary steam distribution pipelines used in conjunction with an approved oil sands scheme do not require a *Directive 056* pipeline licence from the AER under the *Pipeline Act*. For the AER's purpose, with respect to steam distribution pipelines, temporary is defined as not exceeding six consecutive months of service. However, as per the *Pipeline Rules* section 7(2), steam distribution pipelines of a capacity >0.5 m^3 require ABSA design registration, regardless of the time they will be in service. Steam distribution pipelines of an aggregate capacity ≤0.5 m^3 do not require design registration by ABSA.

Steam distribution pipelines confined strictly within the facility surface lease boundaries of a steam-generating plant, satellite, battery, or well site and steam manifolds and measuring facilities at multiwell satellites are considered to form **pressure piping systems** as defined in the *Pressure*

Equipment Safety Regulation (*PESR*) and do not require a licence under the *Pipeline Act*. ABSA requirements apply in these instances.

9.3 CSA Z662 – Clause 14 / Annex I

The *Pipeline Rules* require that pipelines be designed in accordance with *CSA Z662*.

CSA Z662 includes requirements for pipelines distributing steam at temperatures >120°C and pipelines recovering produced reservoir fluids at operating temperatures >230°C. Figure 14.1 of *CSA Z662* illustrates this relationship in a flowchart. Steam distribution pipelines at >120°C or other pipelines with a design temperature >230°C are subject to the design standards of clause 14 of *CSA Z662*, "Elevated Temperature Pipelines." If a pipeline is used only in steam distribution service (i.e., not multiple service or a production pipeline), "Annex I: Oilfield steam distribution pipelines – Alternate provisions" may be used as a design option. All other produced reservoir fluid pipelines with a design temperature ≤230°C may follow clause 4 of *CSA Z662* design standards or, optionally, clause 14 design standards, as ABSA does not allow an existing AER-approved pipeline to be converted to steam distribution service unless the pipeline was originally registered for those services.

9.4 Application for a Pipeline Licence

For pipelines not covered under the exemption for temporary steam distribution pipelines and that traverse or enter land outside the facility surface lease boundaries of a plant, well site, satellite, or battery, the applicant must apply to the AER for a licence as required by Part 4 of the *Pipeline Act*.

Under section 7(2) of the *Pipeline Rules*, and as part of the *Directive 056* licence application, the AER requires confirmation that the design of elevated-temperature pipelines has been registered with ABSA in accordance with section 16 of the *PESR*.

Pressure control and overpressure protection are to satisfy the requirements for overpressure protection of clause 4 of *CSA Z662* and section 38 of the *PESR*.

90) If mechanical couplings are used, the *Directive 056* application must confirm the couplings are registered with ABSA.

For more information on the applicability of ABSA design registration and AER licence application, see the flowchart in appendix 3 of this directive.

9.5 Field Construction and Inspection

For elevated-temperature pipelines, applicants are to obtain ABSA design registration before receiving construction approval from the AER. This process is to ensure that pipelines meet the necessary safety and quality standards prior to their operation or modification.

Notice of field construction must be provided to the AER, in accordance with section 9 of the *Pipeline Rules*. Pipeline construction inspections may be conducted jointly or independently by the AER and ABSA.

9.6 Pressure Testing

Pressure testing requirements are specified in Part 3 of the *Pipeline Rules*, and testing of elevated-temperature pipelines must meet *CSA Z662* requirements, including clause 14 or Annex I as applicable.

Notice of pressure test must be provided to the AER in accordance with section 33 of the *Pipeline Rules*.

Test pressures, mediums, and procedures for ABSA design-registered pipelines must be approved by ABSA in accordance with sections 16(1) and 30 of the *PESR*. Testing must be conducted in a manner that satisfies ABSA requirements. Records of the successful pressure test must be in accordance with the *Pipeline Rules*, *CSA Z662,* and sections 31 and 32 of the *PESR*, as applicable. Pressure test inspections may be conducted by the AER and by ABSA, either jointly or individually, and at the sole discretion of each.

9.7 Operations

In accordance with section 7(2) of the *Pipeline Rules,* a licensee must obtain all required approvals from ABSA and the AER before putting the ABSA design-registered pipeline into operation.

In-service inspections and integrity management for ABSA design-registered pipelines must meet both the AER and ABSA requirements. Elevated-temperature pipelines must be included in the company's safety and loss management system (SLMS). The SLMS must also address the duty holder's pressure equipment integrity management requirements in a manner acceptable to ABSA and to the AER for ABSA design-registered pipelines. AER requirements for operation, maintenance, and integrity management of elevated-temperature pipelines are to be addressed as required by the *Pipeline Act* and *Pipelines Rules*.

9.8 Release of Product and Contact Damage (Failure Investigation)

When product is released from, or contact damage occurs to, an elevated-temperature pipeline, the AER must be immediately notified (see section 35 of the *Pipeline Act* and Part 8 of the *Pipeline Rules*).

ABSA requirements for reporting an unsafe condition, accident, or fire must also be adhered to for ABSA design-registered pipelines. Licensee response activities are to follow applicable ABSA requirements.

Response activities may be conducted or directed by the AER and by ABSA, either jointly or individually, and at the sole discretion of each.

10 Comingling of Oil and Gas in a Single Pipeline

10.1 Introduction

Manual 014: Liquid Classification and Well Status Fluid Type Determination for Oil and Gas Wells provides classification criteria for wells. The properties of the liquids produced by a well determine whether it is condensate or oil, which determines whether the well is classified as oil or gas.

Wells producing from a single reservoir usually have the same classification. However, sometimes a well within the group of wells will have a different classification even though its production characteristics are similar. Consequently, a pipeline gathering system could be licensed for a substance category different from the class of the outlier well. This situation would necessitate a separate pipeline to carry similar production from the same reservoir. In such cases, the AER would consider allowing commingling production in a single **pipeline system**.

Commingling of fluids is only intended for cases where well classification results in wells being stranded in an area where the surrounding wells predominantly have a different well classification, but the production compositions of the stranded well are similar to the surrounding wells.

10.2 Criteria for Pipeline Licensing of Commingled Production

This process only applies to the commingling of oil effluent and natural gas. Commingling of oil effluent and natural gas where either one contains H_2S is not permitted.

91) The gas-oil ratio (GOR) must be measured at or converted to standard conditions. Depending on the calculated GOR of the commingled stream, the pipeline may need to be relicensed.

92) Where oil effluent flows into a natural gas pipeline, and the resulting calculated GOR in the downstream line is $\leq$2000 m^3/m^3, the downstream line must be relicensed as an oil effluent pipeline. In this case, a licence amendment is required in accordance with *Directive 056*.

Where oil effluent flows into a natural gas pipeline, the resulting calculated GOR in the downstream line must be >2000 m^3/m^3 for the downstream pipeline to remain licensed as a natural gas pipeline.

Where natural gas flows into an oil effluent pipeline, the downstream oil effluent pipeline remains an oil effluent pipeline regardless of the gas content.

Appendix 1 Definitions

alternative corrosion prevention system	An insulation system designed to move and drain moisture from the pipe exterior and prevent corrosion under the insulation. These systems may be acceptable substitutes for corrosion prevention coatings.
business day	Monday through Friday, excluding statutory holidays.
competent individual	A person who is qualified, trained, and experienced to perform the required duties in accordance with the licensee's safety and loss management System.
corrosion prevention coating	A material applied to the exterior surface of a buried or insulated metallic pipeline to prevent water and other corrodents from contacting the metallic surface.
defective or inoperative	An overpressure protection device that is incapable of stopping the pipeline pressure from exceeding the maximum operating pressure except as allowed in accordance with *CSA Z662*.
ephemeral water bodies	Depressions in the ground surface with a gradient that may carry water during the spring or after heavy rainfall and having little or no evidence of a stream channel or bank development.
maximum operating pressure	The maximum pressure allowed by the licence or approval.
nonsaline water	Water with total dissolved solids less than or equal to 4000 milligrams per litre.
pipeline	As defined in the *Pipeline Act*.
pipeline system	Pipelines required for the measurement, processing, storage, and transportation of oil or gas industry fluids.
piping	Pipe or pipeline contained within the lease site; may or may not be aboveground.
pressure piping system	As defined by in the *Pressure Equipment Safety Regulation*, pipe, tubes, conduits, fittings, gaskets, bolting, and other components that make up a system for the conveyance of an expansible fluid under pressure and may also control the flow of that fluid.
pressure plant	As defined in the *Pressure Equipment Safety Regulation*, a **pressure vessel** or a system or arrangement of pressure vessels and the pressure piping system used in connection with the pressure vessel or the system or arrangement of pressure vessels.
pressure vessel	As defined in the *Pressure Equipment Safety Regulation*, a vessel used for containing, storing, distributing, processing, or otherwise handling an expansible fluid under pressure.

processing plant	As defined in the *Pipeline Act*.
pumping unit	Mobile equipment used to pump oil industry fluids and includes pumps, drivers, controls, piping, and other appurtenances.
sensitive receptor	Sites or structures that people or animals may frequently occupy, such as houses, playgrounds, childcare facilities, campgrounds, hospitals, feedlots, pastureland, etc.

Appendix 2 Interpretation of Jurisdictional Relationships for the Design of Pipelines, Pressure Equipment, and Pressure Piping

Background

This appendix is a reference tool to assist licensees in understanding the relationships in design methodology and jurisdiction found in Alberta legislation and relevant industry standards used by the Alberta oil and gas industry:

- American Society of Mechanical Engineers (ASME) *B31.3*, *Process Piping* (2024 edition)
- CSA standard *CSA Z662: Oil and gas pipeline systems*
- *Oil and Gas Conservation Act* (*OGCA*) and *Oil* and *Gas Conservation Rules* (*OGCR*)
- *Pipeline Act* and *Pipeline Rules*
- *Pressure Equipment Safety Regulation* (*PESR*) and *Pressure Equipment Exemption Order* (*PEEO*)
- *Safety Codes Act* (*SCA*)

The reference tool provides information for pipelines, on-lease process piping and equipment, and pressure piping and equipment.

The information provided in this reference tool does not apply to the regulatory jurisdiction for incident response and reporting, nor does it limit the scope of integrity management programs or liability for on-lease piping.

The diagrams provided show typical design and jurisdictional relationships; how facility piping is configured or laid out can influence jurisdiction and is the design engineer's responsibility. The variability of facility piping should be considered when determining design jurisdiction (and incident response and reporting requirements). The diagrams provided are examples and not intended as suggestions of how equipment should be configured nor represent the only way that jurisdiction may be designated. The general principles provided in this appendix apply to alternative layouts.

The simplified example diagrams of well, pipeline, or facility piping configurations demonstrate the principles of design methodology and jurisdiction but do not supersede the requirements in the applicable acts, regulations, and standards. Although every effort has been made to ensure information accuracy, the user is responsible for ensuring the facility or pipeline complies with all requirements, regardless of the examples provided.

This edition of the tool supersedes the one in the December 2011 edition of *Directive 077* and is not intended to be applied retroactively.

The interpretations provided in this reference tool apply to all oil and gas pipelines in Alberta except the following:

- a pipeline situated wholly within the property of a refinery, **processing plant**, coal processing plant, marketing plant, or manufacturing plant
- a pipeline regulated by the Canada Energy Regulator
- a gas or oil fuel pipe wholly within the property of a consumer
- a boiler, **pressure vessel**, or pressure piping system within the meaning of the definitions under the *SCA*
- low-pressure gas distribution pipelines

Principles Used in Interpretation

- This reference tool does not cover design and licensing requirements for a wellhead; refer to the *OGCA*. If a single valve is shown on the wellhead outlet, that valve is considered part of the wellhead as it isolates the wellhead.
- Except in the case of a single valve on the wellhead outlet, the first valve inside the lease boundary is usually interpreted as the end of the *Pipeline Act* jurisdiction because this valve is the first isolation point for the pipeline. The entire valve is considered to be within the *Pipeline Act* jurisdiction.
- A pig trap connected to a pipeline under the *Pipeline Act* jurisdiction is generally considered part of the licensed pipeline, including any connected piping and valving used to operate and isolate the pig traps and the piping isolation valve. When a pig trap is part of a pipeline, the first valve inside the lease boundary might not be considered the end of the *Pipeline Act* jurisdiction because all the pipeline up to and including the pig trap could be considered part of the licensed pipeline. Pig traps that are part of a pipeline under *Pipeline Act* jurisdiction are excluded from the *PEEO* under the *SCA* and therefore built in accordance with *CSA Z662*.
- In situations where pipelines are not associated with a licensed facility, such as a pipeline pigging junction, it would be impractical to consider any connecting piping outside of the traps and isolation piping to be on-lease piping because all piping is functionally part of the pipelines. In such a case, treating all piping as part of a *Pipeline Act* pipeline system is reasonable.
- Where multiple pipelines enter a common facility, the licensee may designate the jurisdictional break at the individual block valves (i.e., first isolation valve) on each pipeline if so equipped. Shared piping and pigging equipment inside the facility boundary and inside those pipeline isolation valves could then be designated as under the *OGCA* jurisdiction.

However, in doing so, any piping that might qualify as a "pressure piping system" as defined in the *PESR* is then subject to the *SCA*, and even though the facility may be under the jurisdiction of the *OGCA*, the *SCA* would apply to the pressure piping system and pigging equipment. The *PEEO* excludes *p*ipelines under the *Pipeline Act* or *OGCA*.

- *CSA Z662* provides an option to allow ASME design for a pipeline within a compressor or pump station licensed as a pipeline installation (either a standalone licence or as part of a pipeline licence). The licensee must also comply with any requirements of *CSA Z662* that are additional to those specified by ASME.
- Jurisdiction does not change where the pipeline crosses a lease boundary. Pipelines entering or leaving a lease may travel some distance before reaching the first isolation valve or other facility piping, as the case may be.
- It may be helpful in interpretation to consider that jurisdiction under the *Pipeline Act* ends with the last flange face that bolts to equipment under a different design jurisdiction.
- On-lease piping designated under the *OGCA* does not have a design code specified and may be designed and built as either ASME B31.3 piping or *CSA Z662* piping.
- If the AER requests, licensees are expected to support their claims of jurisdictional assignment based on their engineering design drawings.

Notes on Design and Licensing Requirements

In general, pipelines and facility piping fall within three categories concerning their design requirements: pipeline, on-lease or facility piping, and **pressure plant** piping (under ABSA).

Pipeline

Includes pipelines entering or leaving a lease boundary (including its designated on-lease isolation valve), piping within a pipeline installation lease boundary, and general pig traps and their ancillary piping connected directly to a single pipeline.

- Pipe and components under the jurisdiction of the AER and licensed under *Directive 056: Energy Development Applications and Schedules* must comply with the design requirements of *CSA Z662*.
- The scope diagrams in clause 1 of *CSA Z662* identify the types of facilities where *CSA Z662* design would and would not be required. However, *CSA Z662* is an acceptable design standard for on-lease piping where the OGCA applies.
- Apply *CSA Z662* design requirements to *Pipeline Act* jurisdiction pig traps and the piping and valving used to operate the pig trap or to isolate the pig trap.

On-Lease Piping

Includes piping and components within an AER-licensed facility considered not part of a pipeline nor a "pressure plant" pressure piping system.

- Piping and components included in a facility licensed under *Directive 056*or as a part of an unlicensed AER facility are under the jurisdiction of the *OGCA* and *OGCR*, which do not specify a design code or standard. Such piping may use either *CSA Z662* or *ASME B31.3* design, provided that whichever standard is selected is used for all aspects of that piping. If the piping constitutes a pressure piping system, it falls under the jurisdiction of the *SCA*.
- On-lease piping with pig traps may use either *CSA Z662* or *ASME B31.3* design standards, provided that piping is not interpreted as a pipeline and not interpreted as under *SCA* jurisdiction.
- Piping crossing between adjacent and abutting facility surface leases can be considered on-lease piping. Leases must abut, and the piping cannot pass through any private or public lands between the leases.
- Piping considered to be on-lease or facility piping
  - is not part of the *SCA* "pressure plant" pressure piping system;
  - is outside the scope of *CSA Z662* as per the scope diagrams in clause 1 of *CSA Z662*, examples being production facilities and well sites; and
  - is not licensed as a pipeline.

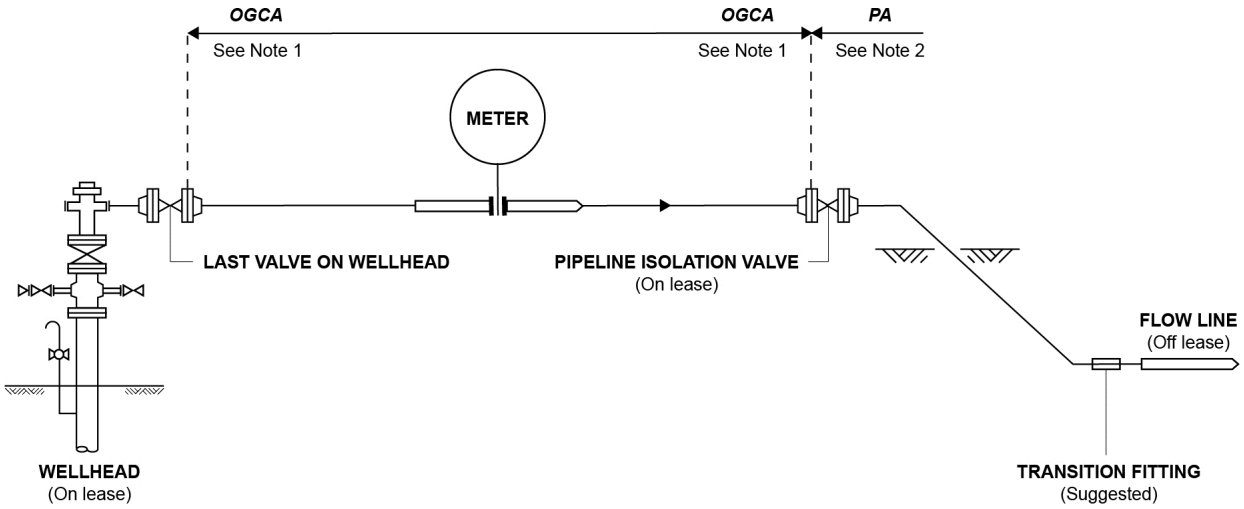
Pressure Piping

Includes piping and components the *SCA* and *PESR* identify as part of a "pressure plant" pressure piping system.

- "Pressure piping" is not under AER jurisdiction as per the *Pipeline Act* and *Pipeline Rules* and does not follow *CSA Z662*.
- A "pressure plant" pressure piping system is within ABSA design jurisdiction and is administered by ABSA; it may exist within an AER-licensed facility or installation.
- Pressure piping systems and their components are within ABSA design jurisdiction and are administered by ABSA under the *SCA*. A pressure piping system may exist within an AER-licensed facility or installation.
- Both ABSA and the AER have roles respecting pipelines operating in steam or elevated-temperature services. ABSA conducts the technical design review and registration, and the AER licenses the pipeline.

Interpretation Diagrams

Example 1: Single production well (well site with no "pressure plant")

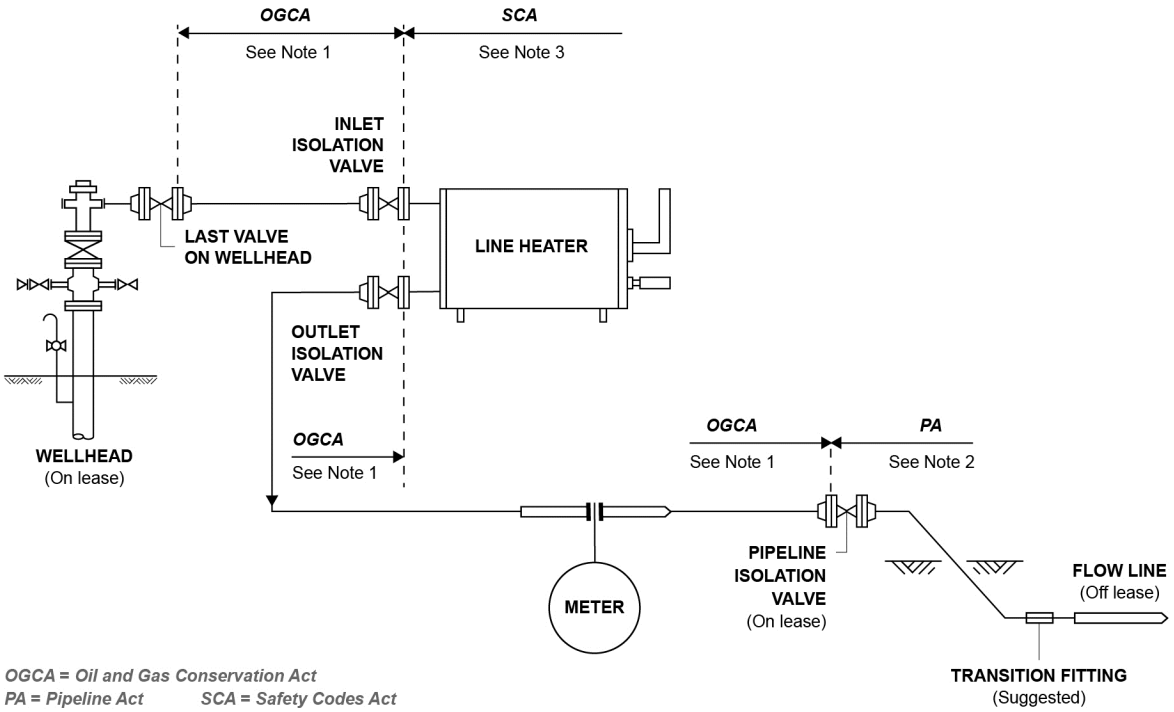


OGCA = Oil and Gas Conservation Act
PA = Pipeline Act *SCA = Safety Codes Act*

Design criteria	Note 1: on-lease piping	Note 2: pipeline
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor part of a "pressure plant" pressure piping system.	A pipeline and its components entering or leaving a lease boundary up to and including the first designated isolation valve.
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*
Design jurisdiction	AER	AER
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*
Comments	Metering is covered by the *OGCR*.	Transition fittings may be mandatory in applicable sour service pipelines.

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. This example does not require facility licensing.
Other comments	There is no "pressure plant" as per the SCA/*PESR;* therefore, no "pressure piping system" is present on site. If the lease isolation valve is part of the wellhead and there are no other on-site isolation valves, the well shutoff valve is considered part of the wellhead, and all piping leaving the valve considered a pipeline.

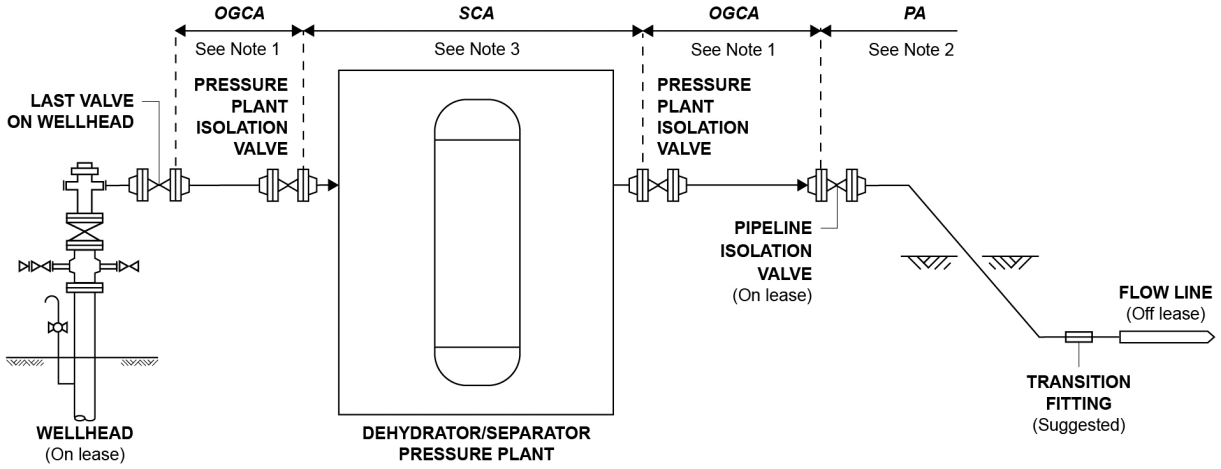
Example 2: Single production well (well site with line heater)



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor part of a “pressure plant” pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a “pressure plant” pressure piping system, including interconnecting piping between “pressure plants.”
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*SCA* and *PESR*
Comments	Metering is included in the *OGCR*.	Transition fittings may be mandatory in applicable sour service pipelines.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. This example, as shown, does not require facility licensing. In some cases, a line heater may require licensing (see *Directive 056*).
Other comments	In this example, the “fired-heater pressure coil” is a single component of a “pressure plant.”

Example 3: Single production well (well site with only a dehydrator and/or separator "pressure plant")

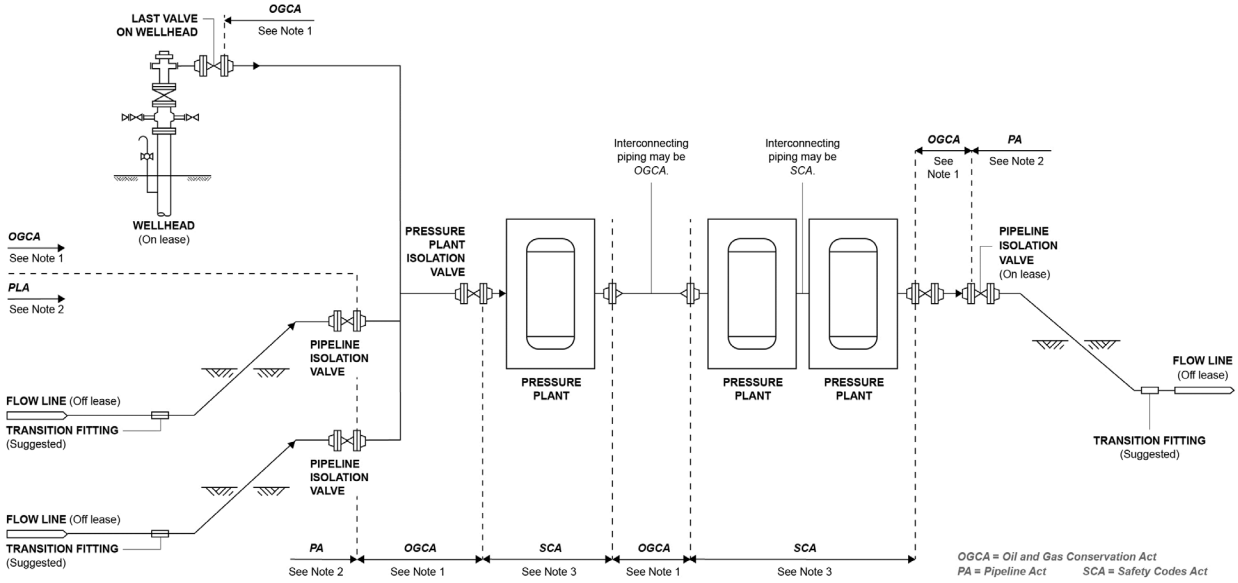


OGCA = Oil and Gas Conservation Act
PA = Pipeline Act *SCA = Safety Codes Act*

Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor part of a "pressure plant" pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a "pressure plant" pressure piping system, including interconnecting piping between "pressure plants."
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*Safety Codes Act* and *PESR*
Comments		Transition fittings may be mandatory in applicable sour service pipelines.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Depending on equipment configuration and H_2S content, this may qualify as a facility and require a *Directive 056* application for a facility licence. All on-lease piping, pressure piping, and equipment are included within this licence.
Other comments	This well-site configuration includes a "pressure plant" as per the *SCA*.

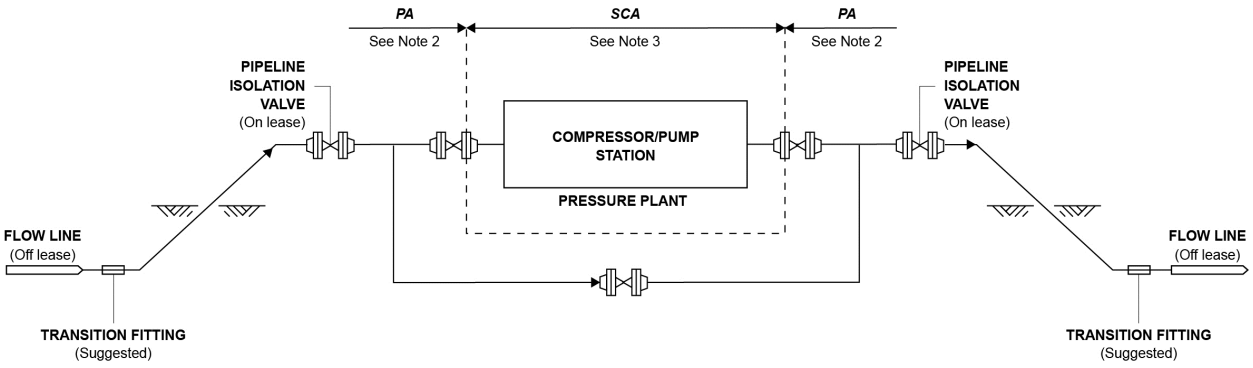
Example 4: Gas satellite or group gas gathering facility with a "pressure plant"



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor part of a "pressure plant" pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a "pressure plant" pressure piping system, including interconnecting piping between "pressure plants."
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*SCA* and *PESR*
Comments		Transition fittings may be mandatory in applicable sour service.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Depending on equipment configuration and H_2S content, this site may qualify as a facility and require a *Directive 056* application for a facility licence. All on-lease piping, pressure piping, and equipment are included within this licence.
Other comments	This well-site configuration includes multiple "pressure plants" as per *SCA*. As shown in this example, depending on the equipment configuration, vessels, or equipment under the *SCA* may be connected by pressure piping within the scope of the *SCA*, or piping may be distinct from the *SCA*, in which case it may be designed as per the *OGCA* and *OGCR*.

Example 5: Compressor or pump station licensed as pipeline installation (downstream)

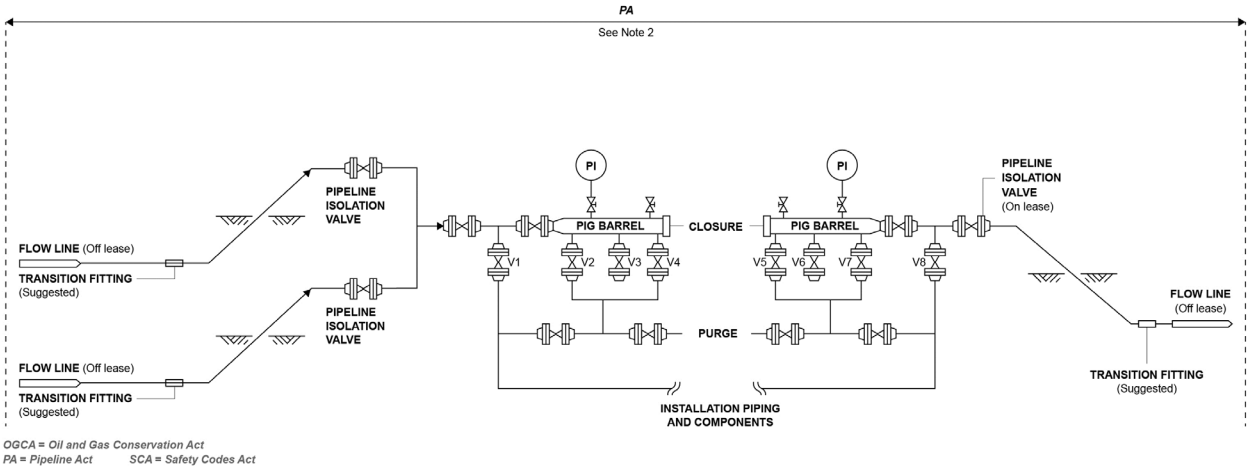


OGCA = Oil and Gas Conservation Act
PA = Pipeline Act *SCA = Safety Codes Act*

Design criteria	**Note 2: pipeline**	**Note 3: pressure piping**
General design jurisdictional relationship	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Piping and components identified by SCA/*PESR* as being part of a "Pressure Plant," including interconnecting piping between "Pressure Plants,"
Design legislative authority	*Pipeline Act and Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	ABSA
Design code and code of construction	*CSA Z662* *CSA Z662* permits the optional use of *ASME B31.3* to design piping systems for compressor and pump stations.	*SCA* and *PESR*
Comments	Transition fittings may be mandatory in applicable sour service. A compressor or pump unit that is functionally part of an upstream facility would be included within the design of the upstream facility.	

Licensing requirements	Pipeline licensing for a downstream compressor or pump station is covered under the *Directive 056* application for a pipeline installation license. The pump or compressor station would be a pipeline installation and may also include associated piping and other equipment.
Other comments	None.

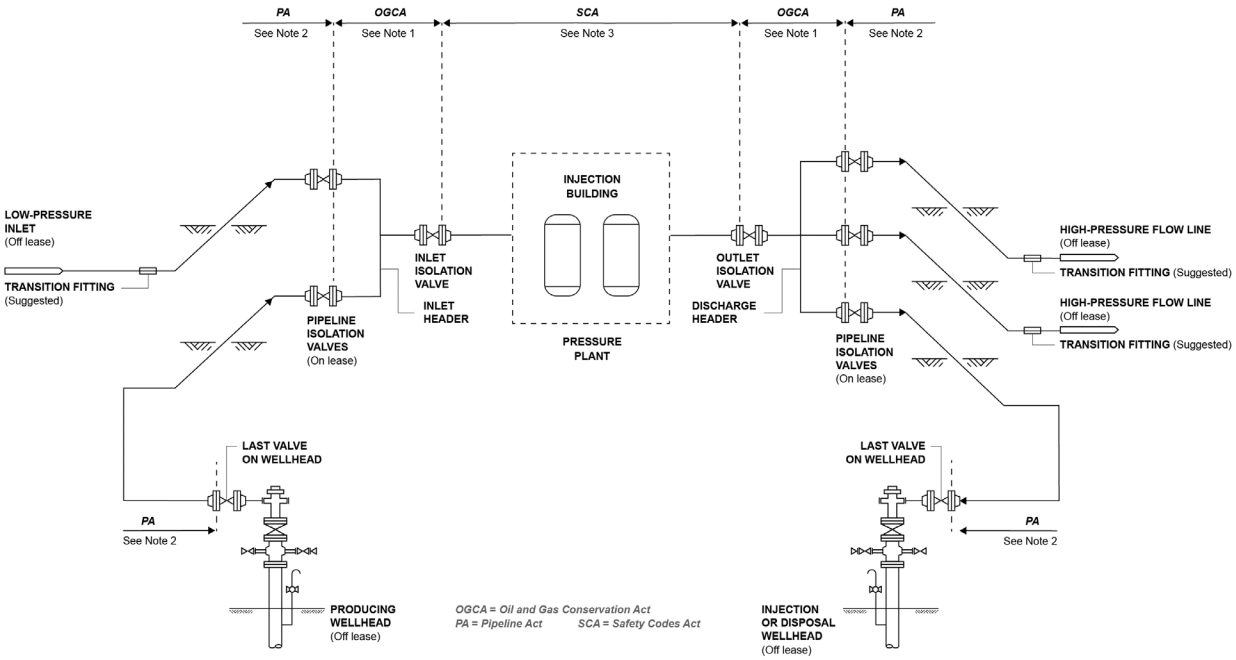
Example 6: High-pressure pipeline junction on a pipeline right-of-way



Design criteria	**Note 2: pipeline**
General design jurisdictional relationship	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.
Design legislative authority	*Pipeline Act* and *Pipeline Rules*
Design jurisdiction	AER
Design code and code of construction	*CSA Z662*

Licensing requirements	Pig barrels are part of the pipeline.
Other comments	Because all equipment is on the pipeline right-of-way and no facility surface lease is involved, all equipment is considered to be pipeline.

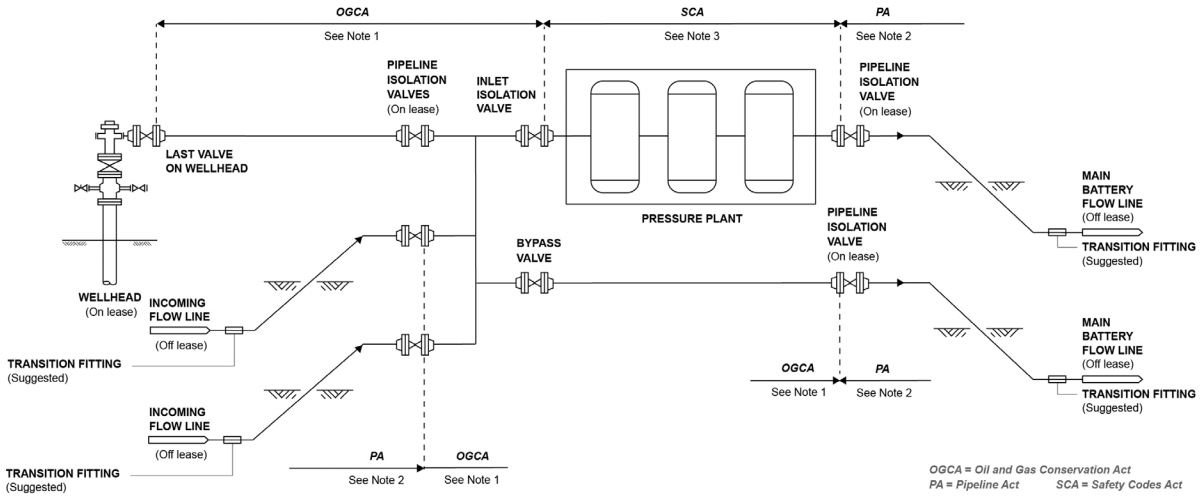
Example 7: Source water collection, injection, and disposal—wells are off lease



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor part of a “pressure plant” pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by SCA/*PESR* as part of a “pressure plant” pressure piping system, including interconnecting piping between “pressure plants.”
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*SCA* and *PESR*
Comments		Transition fittings may be mandatory in applicable sour service.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Site on-lease piping, pressure piping, and equipment are covered under the *Directive 056* application for a facility licence.
Other comments	Wells are off site; thus, the lines to the facility are a pipeline. This configuration includes a “pressure plant” as per the *SCA*.

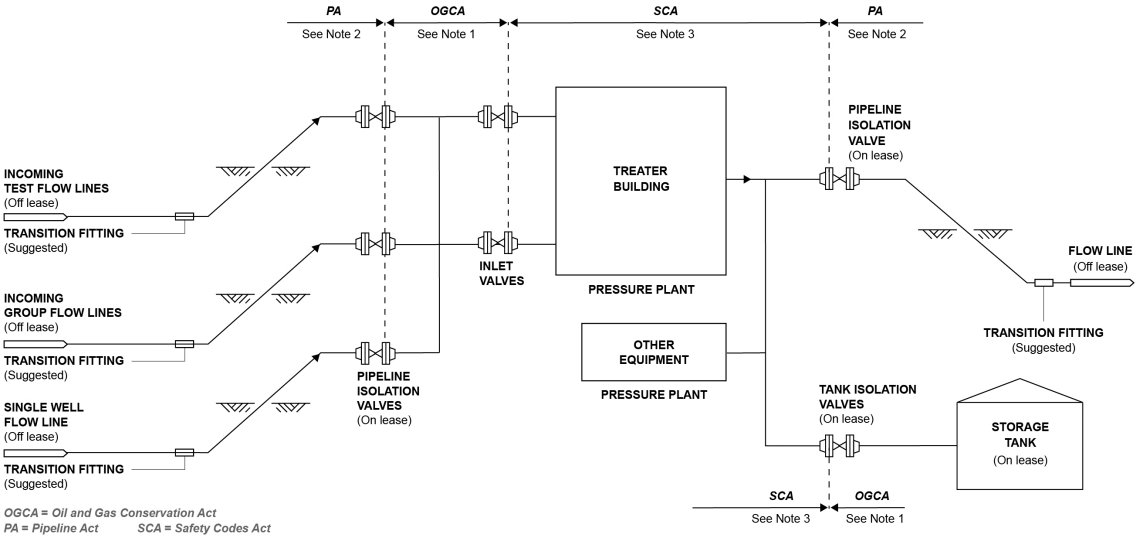
Example 8: Oil or gas satellite with header to group pipelines



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered to be a pipeline nor part a “pressure plant” pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a “pressure plant” pressure piping system, including interconnecting piping between “pressure plants.”
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*Safety Codes Act* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*SCA* and *PESR*
Comments		Transition fittings may be mandatory in applicable sour service.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Site on-lease piping, pressure piping, and equipment are covered under the *Directive 056* application for a facility licence.
Other comments	This configuration includes a “pressure plant” as per the *SCA* and an on-lease wellhead.

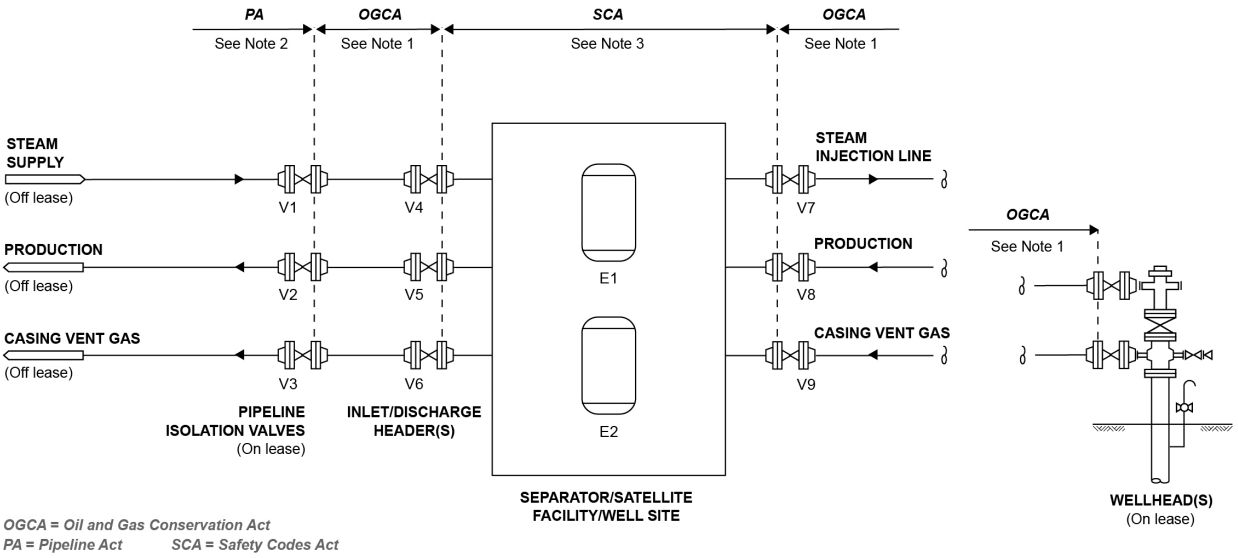
Example 9: Oil battery



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered to be a pipeline nor pat of a "pressure plant" pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a "pressure plant" pressure piping system, including interconnecting piping between "pressure plants."
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act and Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*	*SCA* and *PESR*
Comments		Transition fittings may be mandatory in applicable sour service.	

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Site on-lease piping, pressure piping, and equipment are covered under the *Directive 056* application for a facility licence.
Other comments	This facility configuration includes a "pressure plant" as per the *SCA*. In this example, the tank is part of the battery lease and not part of a "pipeline installation." If the oil storage tank is not included in a facility lease, it would require a licensed pipeline to connect to it. If the tank is a "pipeline installation," it would require a surface lease to accommodate it at that location.

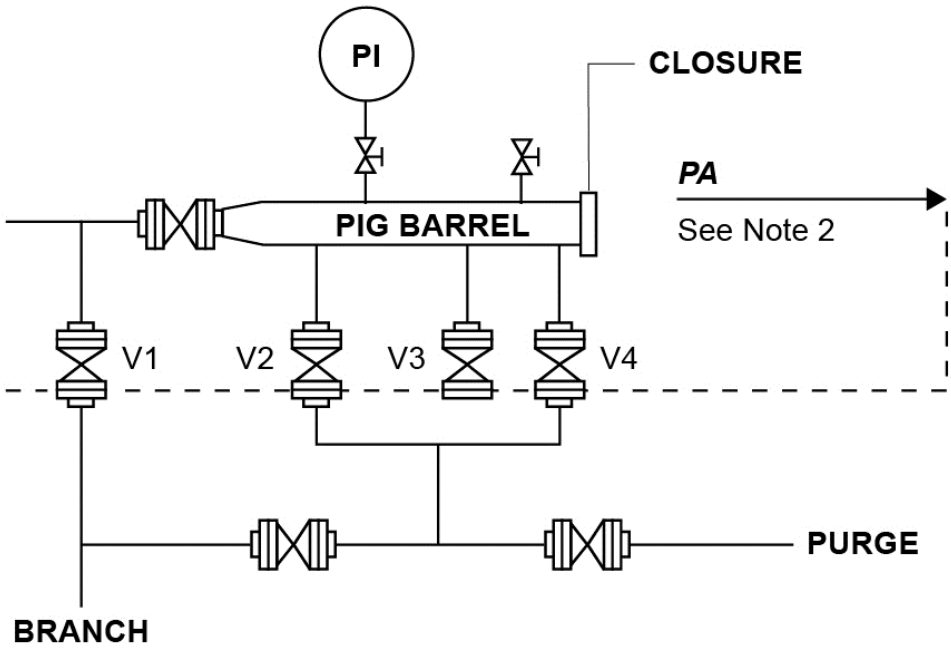
Example 10: Heavy oil or thermal in situ facilities



Design criteria	Note 1: on-lease piping	Note 2: pipeline	Note 3: pressure piping
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor a "pressure plant" pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.	Pipe and components identified by *SCA/PESR* as part of a "pressure plant" pressure piping system, including interconnecting piping between "pressure plants."
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*	*SCA* and/or *PESR*
Design jurisdiction	AER	AER	ABSA
Design code and code of construction	*CSA Z662* or *ASME B31.3*. If *CSA Z662* is used, clause 14 or *Annex I* are applicable for steam >120°C, and clause 14 is applicable for produced fluids >230°C.	*CSA Z662* clause 14 or *Annex I* are applicable for steam >120°C, and clause 14 is applicable for produced fluids >230°C. Clause 14 is optional for produced fluids ≤230°C.	*SCA*, *PESR*, and ABSA *IB10-006: Steam Pipelines* (latest revision).

Licensing requirements	Pipeline licensing is covered under the *Directive 056* application for a pipeline licence. Heavy oil and thermal facility applications follow *Directive 056* licensing requirements. Site on-lease piping, pressure piping, and equipment are covered under the *Directive 056* application for a facility licence. See *Directive 023: Oil Sands Project Applications* for thermal recovery scheme approvals. Steam and elevated-temperature pipelines may require registration with ABSA as per *Directive 077, Directive 056, CSA Z662* (clause 14, Figure 14.1), and *ABSA IB10-006, Steam Pipelines* (latest revision).
Other comments	This facility configuration includes a "pressure plant" as per the *SCA*.

Example 11: Generalized pig trap—component of pipeline licence

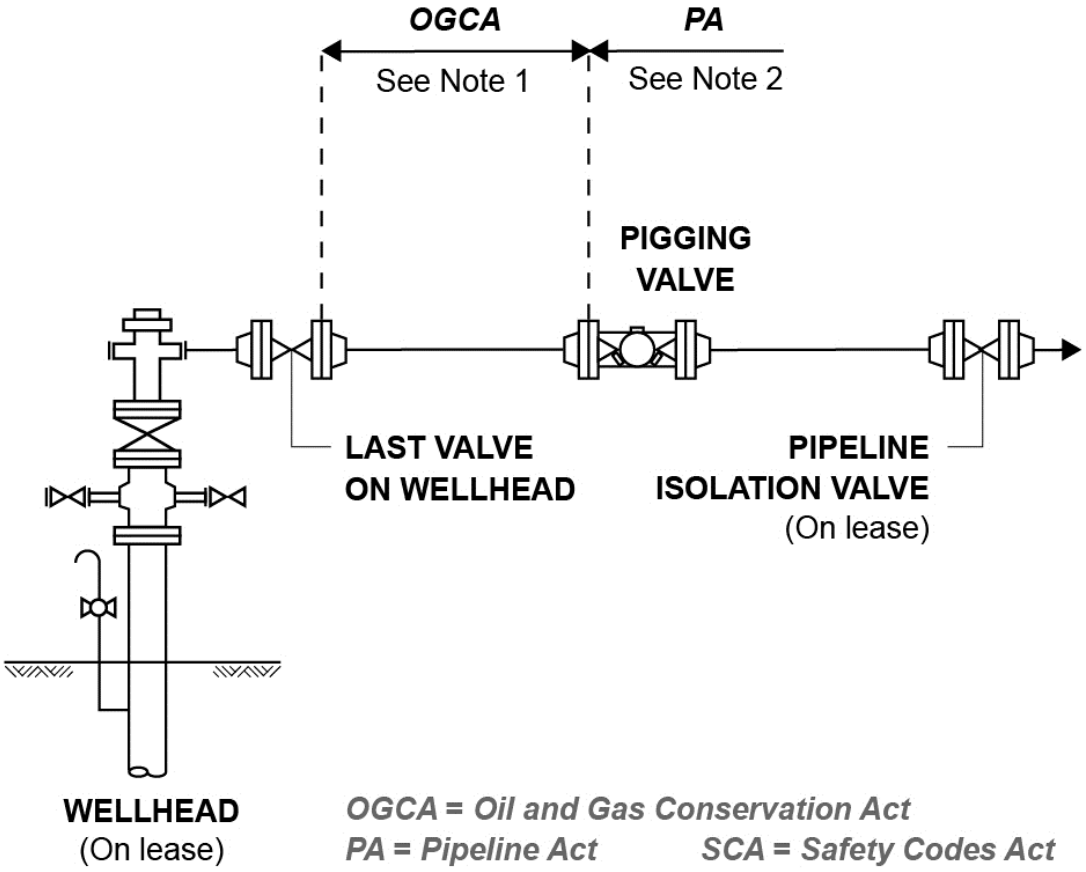


OGCA = Oil and Gas Conservation Act ***PA = Pipeline Act***
SCA = Safety Codes Act ***PESR = Pressure Equipment Safety Regulation***

Design criteria	**Note 2: pipeline**
General design jurisdictional relationship	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve. The branch and purge lines and valves could be either pipeline or on-lease pipeline, depending on the type and configuration of other equipment.
Design legislative authority	*Pipeline Act* and *Pipeline Rules*
Design jurisdiction	AER
Design code and code of construction	*CSA Z662*

Other comments	In this example, the riser and pig trap are included under the *Directive 056* pipeline licence.

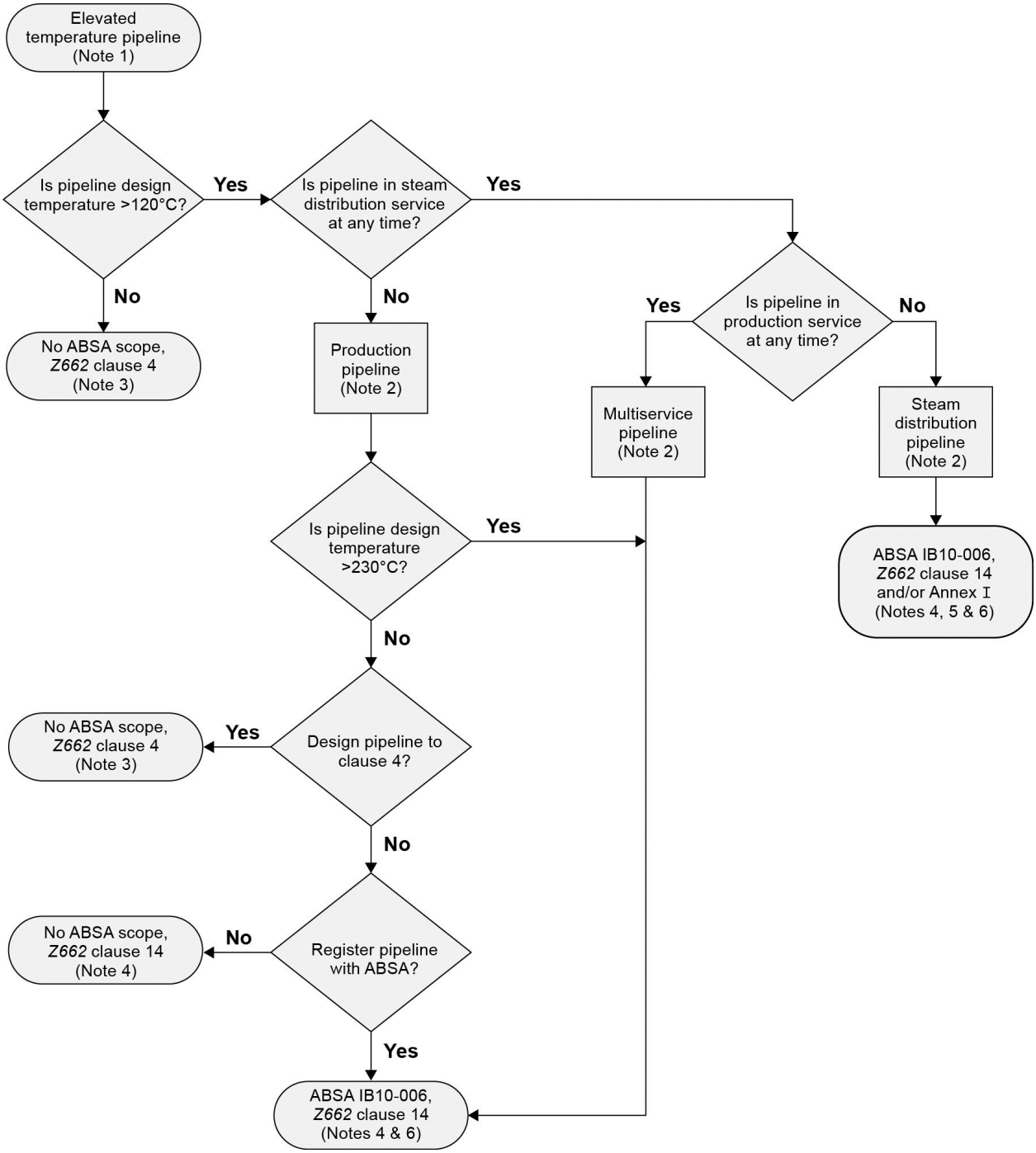
Example 12: Pigging sender with pigging valve



Design criteria	Note 1: on-lease piping	Note 2: pipeline
General design jurisdictional relationship	Piping and components wholly within well sites or facilities and not considered a pipeline nor a "pressure plant" pressure piping system.	A pipeline and components entering or leaving a lease boundary up to and including the first designated isolation valve.
Design legislative authority	*OGCA* and *OGCR*	*Pipeline Act* and *Pipeline Rules*
Design jurisdiction	AER	AER
Design code and code of construction	*CSA Z662* or *ASME B31.3*	*CSA Z662*
Comments		Transition fittings may be mandatory in applicable sour service.

Other comments	In this example, the pigging valve is included under the Directive 056 pipeline licence in the same manner as for a pig trap.

Appendix 3 Jurisdictional Interpretation for Elevated-Temperature Pipelines



Notes:

1 All pipelines require an AER licence, including pipelines running between distinct mineral surface leases (MSLs) not considered to be within the same lease boundary (e.g., pipelines between steam-assisted gravity drainage [SAGD] well pads and the central processing facility are not considered as being on the same lease.)

2 Production pipelines gather production (may be in liquid, vapour, or multiphase form and may include recovered steam) and are not in any other service.

Steam distribution pipelines distribute steam from a steam-generating facility to steam-injection wells or well-pad facilities and are not in any other service. Multiservice pipelines are pipelines in steam distribution service or production service at various times.

3 "Regular *Z662*" refers to conventional steel pipeline design using clauses 3 to 10 and 16 (if sour service) of *CSA Z662: Oil and gas pipeline systems*.

4 "*Z662* clause 14" refers to clause 14 (design) of *CSA Z662* with other *CSA Z662* clauses (3 to 10 and 16) as applicable.

5 "*Z662 Annex I*" refers to *CSA Z662 Annex I* design with clause 14 and other *CSA Z662* clauses (3 to 10 and 16) as applicable.

6 ABSA *Directive IB10-006* requirements apply, including ABSA design registration. *ABSA IB10-006* and ABSA registration only apply to pipelines with design pressure greater than 103 kPa(g) and volume greater than 0.5 m^3.