Directive 023

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Oil Sands Project Applications

Contents

Abbreviations

ADR	alternative dispute resolution
AER	Alberta Energy Regulator
ATS	Alberta Township Survey
BA	business associate
BGWP	base of groundwater protection
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CPF	central processing facilities
CSS	cyclic steam stimulation
DBIP	developable bitumen in place
EIA	environmental impact assessment
EPEA	*Environmental Protection and Enhancement Act*
ESRI	Environmental Systems Research Institute
LHV	lower heating value
LSD	legal subdivision
MOP	maximum operating pressure
OBIP	original bitumen in place
OSCA	*Oil Sands Conservation Act*
OSCR	*Oil Sands Conservation Rules*
PFD	process flow diagram
SAGD	steam-assisted gravity drainage
TDS	total dissolved solids
UWI	unique well identifier

1 Introduction

1.1 Purpose of This Directive

Directive 023: Oil Sands Project Applications sets out the requirements for filing an application with the Alberta Energy Regulator (AER) under sections 10 and 11 of the *Oil Sands Conservation Act* (*OSCA*). Section 10 governs the approval of a scheme or operation to recover oil sands or crude bitumen and covers in situ and surface or underground mining operations. Section 11 governs the approval of oil sands processing plants and covers bitumen extraction facilities, refineries and upgraders, and certain gas processing facilities. *Directive 023* also sets out the requirements for filing an application under section 13 of *OSCA* to amend a previously approved scheme or processing plant.

This directive does not address the application requirements for primary, enhanced recovery, or experimental schemes for the recovery of oil sands or crude bitumen or the requirements to suspend or abandon a scheme or a processing plant.

A scheme or operation for the recovery of oil sands or crude bitumen, any processing plant, or any combination of the previous two will be referred to as an oil sands project throughout this directive. (See appendix 1 for further definitions.)

This directive is designed to apply to all oil sands projects, except where indicated; therefore, the level of detail required may vary from project to project. The level of information provided in the *Directive 023* application needs to reflect the scale of the proposed activity. Each application is considered a standalone submission and a comprehensive package must be supplied to the AER in accordance with this directive. Depending on the scope and scale of an application for a proposed amendment, submission of new or updated environmental information may be required under this directive or the specified enactments (e.g., *Environmental Protection and Enhancement Act* (*EPEA*), *Public Lands Act*, *Water Act*).

Applicants are encouraged to provide as much information as possible to minimize the potential for supplemental information requests.

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 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

This edition of the directive replaces the May 2013 draft edition of *Directive 023* and replaces and rescinds the July 2020 edition of *Directive 086: Reservoir Containment Application Requirements for Steam-Assisted Gravity Drainage Projects in the Shallow Athabasca Oil Sands Area.*

The primary changes to the directive are as follows:

- Removed duplicate requirements that exist in other directives (e.g., *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects*) or provincial legislation, including removal of environmental requirements that are addressed under the specified enactments.
- Aligned socioeconomic requirements with *EPEA*.
- Moved all reservoir containment requirements from *Directive 086* into section 6 of this directive.
- Restructured the environmental and socioeconomic requirements based on the scale of the projects they apply to (e.g., small-scale in situ projects).
- Added a section on in situ life-cycle applications.

1.4 How to Use This Directive

AER requirements that are common to all oil sands project applications and may apply to application amendments are in sections 2 to 5. Additional application requirements specific to the type of oil sands project are in sections 6 to 8 and section 10. Section 9 contains details about the amendment application categories for amending an approved oil sands project. Applicants considering an in situ life-cycle application should refer to section 9.1.

2 Oil Sands Project Preapplication Considerations

This section describes what applicants should consider before applying for an oil sands project.

Applicants may be required to prepare and submit an environmental impact assessment (EIA) report under *EPEA* to the AER.

Applicants are responsible for ensuring that applications submitted under this directive are consistent with any associated EIAs or other regulatory submissions to the AER.

Applicants should refer to section 4 of this directive to comply with requirements to carry out a stakeholder involvement program before filing an application with the AER. Making bona fide efforts to resolve concerns raised about the proposed project as early as possible can greatly facilitate the application review process and may help avoid the need for a hearing.

Applicants are expected to discuss any uncertainties regarding the content or structure of an application with the AER. Applicants are also encouraged to take the opportunity to meet with the AER before filing an oil sands project application to

- notify the AER of their intent to file an application;
- give the AER an overview of the type and complexity of the application; and
- ask any questions, identify issues, and receive clarification about the requirements so that a complete application may be submitted and subsequently reviewed in a timely and efficient manner.

2.1 Incomplete Applications

If an incomplete application is submitted, the AER may request the missing information or return the application as incomplete. If the AER returns an incomplete application, the applicant will be notified in writing of the reason why the application has been returned. The applicant may reapply by submitting a new, complete application.

2.2 Submission Formats

An application will not be registered until the documents have been submitted in the required format.

1) Application documents must be submitted as unlocked, searchable, and indexed PDF files. Supporting attachments and appendices must be included as separate PDF files.
   a) All figures submitted in the PDF documents must have sufficient resolution to be legible.
   b) Maps must include legal subdivision (LSD) coordinates where scale allows.

c) Spatial information must be submitted in both of the following formats:

   i) As maps in the PDF application document.

   ii) As shapefiles that are supported by the Environmental Systems Research Institute (ESRI) ArcView products.

Refer to appendix 2 for further information on how to submit spatial files.

Refer to appendix 3 for instructions on how to submit any required modelling data.

2.3 *Directive 056* Well, Pipeline, and Facility Licences

General

Stakeholder involvement programs followed by an applicant in connection with any oil sands project application or amendment submitted under this directive will satisfy the participant involvement requirements for any subsequent, related *Directive 056: Energy Development Applications and Schedules* licence applications for wells, pipelines, and facilities.

In Situ

Wells, pipelines, and surface facilities associated with in situ oil sands projects must also be licensed in accordance with *Directive 056.*

Any required *Directive 056* licences associated with an in situ oil sands project can only be obtained *after* receiving a project approval under this directive except in the following situations:

- *Directive 056* well licence applications for oil sands evaluation wells may be made at any time. *Directive 056* participant involvement requirements must be satisfied for licences of oil sands evaluation wells that have not been addressed within an AER-approved in situ oil sands project application.
- *Directive 056* well and facility licence applications that are required to support project modifications associated with a category 1 or category 2 project amendment, as defined in section 9 of this directive, may be made at any time. *Directive 056* participant involvement requirements must be satisfied for licences encompassing these modifications that have not been addressed within an AER-approved in situ oil sands project application.

No clearing or site preparation activities for in situ oil sands projects may occur until the applicable *Directive 056* licences have been obtained.

Mining

Directive 056 well licence applications for oil sands evaluation wells may be made at any time. *Directive 056* participant involvement requirements must be satisfied for oil sands evaluation wells that are not within an AER-approved mining project area.

Well licences are not required for oil sands evaluation wells drilled within an approved mining project area, in accordance with Part 2, section 4(5), of the *Oil Sands Conservation Rules* (*OSCR*).

Facility licences for surface facilities associated with oil sands mine approvals are not issued under *Directive 056.*

Processing Plants

Facility licences for surface facilities associated with oil sands processing plant approvals are not issued under *Directive 056.*

3 General Application Requirements

This section describes the applicant eligibility requirements, the transfer of approval requirements, and the project description requirements for in situ and mining oil sands applications.

3.1 Applicant Eligibility

In order to apply for an in situ or mining project, an applicant must have a business associate (BA) code, obtained through Petrinex. For in situ projects, the applicant must be eligible to hold an AER licence or approval as determined by the AER under *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*.

2) The applicant must be the intended approval holder and legally responsible for the project.

3) If the project operator is different from the applicant, the operator must be identified and their relationship with the applicant made clear.

3.2 Transfer of Approval

All AER approvals must be kept current and must reflect the approval holder that is responsible for the project. No change in the approval holder is in effect until the approval has been amended to reflect the change.

4) In order to transfer the approval, provide the following information:

   a) The AER project approval number.

   b) For a change to the approval holder's name, evidence of the change or details on when such evidence was filed with the AER. For a change to the name of the approval holder for multiple projects, a list of the approval numbers.

   c) For an approval holder change, a completed version of the Transfer of Approval agreement in appendix 9.

      If the present holder no longer exists, evidence that the new holder is the company that will assume responsibility for the project and evidence that the present approval holder no longer exists.

3.3 Project Description Requirements

The level of detail needs to be proportionate to the scale of the proposed project.

5) Identify the applicant and the project name.

6) Describe any partners involved in the project and state their roles and responsibilities.

7) State the section of *OSCA* under which the application is being made.

   For example:

   ABC Company is applying for an approval to construct and operate an in situ oil sands project under section 10 of *OSCA*.

8) Provide an overview of the project and include the following information, where applicable:

   a) the location of the project and its distance to the nearest communities[1]

   b) target resource

   c) project components

   d) recovery technology

   e) annual production capacity over the life of project

   f) project development phases

   g) energy sources used for recovery and processing

   h) intended method of transporting

      i) product and by-products to market

      ii) ongoing hydrocarbon receipts such as diluent or solvent

   i) water sources and estimated volume of annual use

9) Provide a map of the project that includes the following information, where applicable:

   a) project area and development area

   b) lease boundaries

   c) water bodies

   d) drainage patterns

   e) mine sites

   f) processing plants

   g) pad locations

   h) central processing facilities (CPFs)

[1] Applicants are encouraged to state the proximity of the project to Indian reserves, Métis settlements, and, if the information is publicly available, registered traplines.

   i) storage or disposal structures
   j) roads, pipelines, and other significant infrastructure

10) Provide a regional map of the project that shows
   a) urban centres;
   b) major industrial operations;
   c) water bodies; and
   d) road, rail, pipeline, power and utility corridors, and other significant infrastructure.

The regional map is expected to provide a broader context of the project location and development surrounding and within the project area.

11) Provide a project schedule that includes the following milestones:
   a) regulatory application submissions and anticipated approvals
   b) construction, including estimated start and completion dates
   c) operations, including estimated start and completion dates

12) Provide a statement regarding the ownership of mineral rights for the oil sands project.

The AER will not issue an approval unless the applicant is a mineral rights holder.

13) Provide a summary of surface rights access and ownership within the project area.

    Include existing surface rights holdings and Crown land.

14) Provide a table showing the LSD coordinates of the oil sands project. For each LSD, identify the owner of the surface rights, as well as the owner of the rights to any other subsurface resources.

15) Describe the economic benefits of the project that accrue to
   a) the proponent,
   b) Indigenous communities,
   c) local and regional communities,
   d) the local authority,
   e) Alberta, and
   f) Canada.

16) Estimate total project cost for both construction and operation stages and percentage of expenditures expected to occur in the region.

17) Describe the royalties and taxes that would accrue to the municipal, provincial, and federal governments.

Section 10.1 contains additional socioeconomic information that must be provided for small-scale in situ projects, which are in situ projects with a production capacity of 2000 m^3 or less of crude bitumen per day.

18) List all requests for waivers or variances from applicable AER requirements, including the reasons for the requests.

4 Stakeholder Involvement

19) An applicant must carry out a stakeholder involvement program to inform parties about the proposed oil sands project and, where feasible, to make bona fide efforts to address and resolve concerns raised about the proposed project.

The extent of stakeholder involvement efforts required by an applicant will depend on the nature, size, and scope of the oil sands project and may range from the publication of a notice in a local newspaper to meeting directly with persons who raise concerns about and file a statement of concern to the proposed activities.

An applicant should tailor its stakeholder involvement program to fit the unique circumstances of its project. An applicant should consider that oil sands projects often involve multiple authorizations issued by different agencies for which the stakeholder requirements may vary. Where practical, the AER prefers that applicants conduct a single stakeholder involvement program that encompasses information sharing and communication with all stakeholders.

To ensure that a project-specific stakeholder involvement program addresses the relevant requirements, applicants are advised to review the appropriate regulatory guidance documents and contact the relevant government authorities directly to answer any outstanding questions before commencing any engagement activities.

4.1 Stakeholder Involvement Program

20) The applicant must determine who to include and tailor its stakeholder involvement program accordingly.

The AER encourages applicants to provide project-related information and notification to a range of potential stakeholders and to make bona fide efforts to address and resolve concerns and objections raised in connection with the proposed activities.

21) Applicants must document their efforts to resolve concerns and be prepared to provide detailed information about those efforts to the AER on request.

Generally, a stakeholder involvement program for applications filed under this directive should include persons or groups who have legal rights to conduct activity on the land (including landowners, occupants, residents, local First Nations and Métis groups, and local authorities) and those who have rights to the underlying mineral, energy, or other natural resources (including Freehold and Crown mineral owners and lessees).

22) At a minimum, stakeholder involvement activities must include

a) landowners in the project area and the off-setting sections,

b) oil sands leaseholders in off-setting quarter sections, and

c) petroleum and natural gas leaseholders and Freehold mineral owners of any unleased lands in the project area and the off-setting sections.

The applicant should provide the name of someone who represents the company and may be contacted about the collection of personal information in connection with the application, as well as the applicant's privacy policy.

Stakeholder involvement efforts are intended to

- inform parties of the nature of the oil sands project and its effects,
- respond to questions and concerns, and
- facilitate discussion on the proposed option, alternatives, and mitigation measures.

23) An applicant must begin its stakeholder involvement program before filing an application with the AER.

Applicants are expected to continue their stakeholder involvement activities throughout the life of the oil sands project.

The AER expects applicants to respond and engage in a meaningful way with any party that has raised a concern or has questions regarding the oil sands project and to make reasonable efforts to address concerns raised before filing an application. The AER does not expect complete consultation and comprehensive resolution of all concerns before the applicant files an application. Applicants should be aware that incomplete or deficient stakeholder involvement activities may result in delays in processing an application, the closure of an application, or a hearing on the application.

4.2 Information Package

24) An information package must be developed and distributed to all parties that are part of the applicant's stakeholder involvement program and to any other party that requests it.

25) The information package must be written in plain language and must contain sufficient information so that parties understand the oil sands project clearly and can determine whether it has any effects on them.

Information packages relating to amendment applications should provide a description of the changes to the approved project.

26) The information package must contain the following:

a) The applicant's name, postal address, phone number, fax number, and email address.

b) The location of the oil sands project. Include a map at a scale that sufficiently encompasses the stakeholder involvement area. Multiple maps may be included, if necessary, given the scale. Provide the LSD coordinates for the oil sands project.

c) A description of the oil sands project, including utilities and infrastructure.

d) A high-level summary of the environmental effects of the oil sands project and the mitigation measures. The summary must include effects on

   i) land use,

   ii) air quality,

   iii) groundwater, and

   iv) water bodies.

e) A high-level summary of the socioeconomic effects of the oil sands project and the mitigation measures.

f) A high-level discussion of the potential implications to developing lands adjacent to the oil sands project.

g) A schedule that shows regulatory, construction, and operating milestones.

4.3 Application Requirements

27) Discuss the stakeholder involvement area and the criteria that were used to determine it. Include a map of the stakeholder involvement area that shows

   a) the project area,

   b) existing land uses, and

   c) the locations of persons included within the stakeholder involvement area (including landowners, mineral leaseholders, owners of any unleased lands in the project area and the off-setting sections, and oil sands leaseholders in the project area and off-setting quarter sections).

28) Describe the stakeholder involvement program.

   a) Discuss activities completed to date and any future planned activities. Include a table identifying the date of the activity, location, participating parties, and issues raised. Identification of parties should be at a high level (i.e., by organization or by occupation or activity [e.g., trappers, landowners]).

b) Discuss the results of the engagement activities, including how feedback (any concerns or issues raised) was responded to or incorporated into the project and the efforts undertaken to address outstanding concerns or objections.

29) Provide a copy of the information package. Copies of any AER documents provided to a party do not need to be included but must be identified.

30) An applicant must *not* submit personal information about the parties contacted as part of its stakeholder involvement program. However, an applicant must retain and make available to the AER upon request

a) a list of notifications issued,

b) a list of parties consulted,

c) all communication records with parties (e.g., letters, notifications, emails),

d) all party contact information, and

e) all registered mail or courier tracking records.

4.4 Other Related Processes and Guidance

Applicants are reminded of their obligations under the *Personal Information Protection Act*. This includes disclosing the need and purpose for collecting any personal information; the circumstances under which the information will be disclosed; and any details on the security, retention, and the ultimate destruction of this information. The name of the person to be contacted regarding personal information collection and the company's privacy policy should also be provided, with all details consistent with the applicant's established privacy policy.

In its attempt to address concerns and objections, an applicant may wish to use the AER's alternative dispute resolution (ADR) process. ADR includes a variety of options to manage disputes, such as direct negotiation between the parties, AER facilitation, and third-party mediation or arbitration.

More information on ADR can be found on the AER website, www.aer.ca.

5 Environmental Requirements

This section sets out the environmental information that must be provided for new and amendment *OSCA* scheme applications. Section 10.2 contains additional environmental information that must be provided for small-scale (i.e., 2000 m^3 or less of crude bitumen per day) in situ projects.

Environmental information for oil sands projects must also be provided for the following: an *EPEA* application, EIA, *Water Act* application, and *Public Lands Act* application, as applicable.

Applicants must evaluate the location, setting, and duration of their operations to determine the extent of anticipated impacts. Larger activities often have impacts over a greater area and longer period of time than smaller activities. In the case of *OSCA* scheme amendment applications, the extent of impacts depends on the spatial and temporal scales of the proposed changes.

Additional environmental requirements may apply for oil sands projects under *EPEA*. Refer to the *EPEA Guide to Content for Energy Project Applications*.

31) In assessing the environmental effects of a project, identify the area within which the project-related effects are expected to occur over the life of the project.

    The assessment area may differ for each component (e.g., land use, wildlife, hydrology). If the applicant identifies that the effects can reasonably be expected to extend beyond the project area (e.g., broader watersheds, airsheds, or well pads or CPFs outside of the project area), the assessment area must be expanded accordingly.

32) If applicable, summarize the monitoring and follow-up activities necessary to assess the effectiveness of mitigations, including the monitoring scope, objectives, and approach.

5.1 Land Use

33) Identify local and regional land-use plans, policies, and approvals that affect the project area, such as Government of Alberta regional and subregional plans (e.g., *Lower Athabasca Regional Plan*), integrated resource plans, and management plans. Discuss project compliance with any applicable plans, policies, and approvals.

5.2 Hydrology

34) Identify and describe the watersheds in the project area.

    Include a watershed- or subwatershed-scale map with topographic contours that shows the hydrological setting overlaid with the project area and, if applicable, the development area.

35) Identify water bodies within the project area.

    Include a map with topographic contours that shows water bodies and crossing structures overlaid with the project area and, if applicable, the development area.

36) Identify locations where the project footprint will be within 100 m of a water body and provide the following:

   a) for any equipment, a description of the equipment and the fluids involved

   b) for any facility, a discussion of the measures that will be used to minimize the risk of a spill and, in the event of a spill, to prevent the spill from reaching the water body

5.3 Air Quality and Emissions

37) Summarize the project's greenhouse gas management plan, including estimated annual greenhouse gas emissions in tonnes of CO_2 equivalent per year.

    Include a discussion of any project initiatives to reduce or minimize greenhouse gas emissions (such as through the use of energy efficient or capture technologies) and the estimated reduction in emissions.

38) Describe the flare stacks and identify the units they are associated with. The description must address the number and types of flares and expected flare rates (in thousand cubic metres per calendar day [10^3 m^3/cd] at standard temperature and pressure) for both continuous flaring and during emergency conditions.

39) Discuss the mitigation strategies to prevent or minimize flaring events.

The AER expects gas to be recovered during normal operations or flared during emergency conditions.

40) Provide the anticipated gas venting rates (in 10^3 m^3/cd at standard temperature and pressure) and expected emission sources.

41) If gas volumes are sufficient to sustain combustion, the gas must be burned or conserved.

Further flaring and venting requirements for in situ operations can be found in *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*.

5.4 Noise

Applicants seeking approval for oil sands projects must comply with *Directive 038: Noise Control*, which includes undertaking a noise impact assessment before a facility is constructed or in operation.

42) Submit the noise impact assessment as part of the oil sands project application filed under this directive.

6 In Situ Applications

This section describes the information that must be provided as part of an application for an approval to construct and operate an in situ oil sands project.

All geological maps must incorporate available well information and seismic data and be annotated with posted well data values.

Applicants for a new in situ project may apply for a life-cycle approval for certain amendment activities. See section 9.1 for further details.

6.1 Project Geology

A minimum of one section beyond the project area must be used to characterize the geology, and all maps in this section must display the area accordingly.

43) Provide a geological description of the stratigraphic units identified in appendix 4 for the applicable oil sands area and target deposit, including

    a) well log cross-sections that illustrate all units and fluid contacts,

    b) isopach maps for all units, and

    c) structure maps for all units.

44) Discuss the delineation of the bitumen resource for the project area and development area and the delineation's alignment with the guidelines listed in appendix 5. Include

    a) a map of the project area and development area showing the locations of the evaluation wells, cored wells, 3-D seismic area, and 2-D seismic lines; and

    b) a discussion of the seismic acquisition parameters, including bin, frequency, and shot spacing, as well as the processing methods.

In unique circumstances, geological modelling may be required. Applicants are encouraged to contact the AER before submitting their application to discuss if that is the case for their project.

45) If modelling is required, provide

    a) the modelling software (type and version),

    b) the data used to generate the model and any data conditioning or algorithm used for gridding horizontal and vertical resolution, grid rotation from north, and areal extent; and

    c) the model variables (e.g., rock and fluid properties) and model parameters (e.g., anisotropy, mean variogram range, and net-to-gross ratio).

6.2 Hydrogeology

46) The hydrogeological assessment area must

    a) cover the area where there may be effects on groundwater, such as increases or decreases in hydraulic head or changes in groundwater quality, and

    b) be a minimum of six sections beyond the project area.

47) Describe the hydrogeological assessment area and the criteria used to determine it. Include a map of the assessment area overlaid with the project area.

48) Provide the base of groundwater protection (BGWP) across the hydrogeological assessment area.

49) Identify nonsaline and saline aquifers and aquitards as hydrostratigraphic units on a geological column for the hydrogeological assessment area.

50) Discuss the hydrostratigraphy to the deepest nonsaline aquifer in the area. Include general lithology and total dissolved solids (TDS) for each aquifer. Also indicate if there is nonsaline groundwater in contact with bitumen within the development area.

51) Discuss all Quaternary and Neogene channels and river valleys that are connected to bedrock aquifers within the project area. Provide

    a) a map showing the Quaternary and Neogene channels and river valleys in relation to the development area,

    b) cross-sections of channels and river valleys showing the deepest incision in relation to the proposed caprock,

    c) the lithology of the Quaternary and Neogene channels, and

    d) all subcropping formations along the thalwegs.

52) For each aquifer within the hydrogeological assessment area that may be affected by operations, provide

    a) the lateral extent, depth, and thickness of the aquifer;

    b) the hydraulic conductivity;

    c) a hydraulic head contour map showing horizontal gradients and flow directions;

    d) a cross-section showing lithology, hydraulic heads, vertical gradients, flow directions, and interaquifer and surface water connectivity;

e) recharge and discharge areas; and

f) baseline water chemistry, including major ions, TDS, and any other parameters (e.g., dissolved metals, hydrocarbon content) that could be affected.

53) Identify water source wells, disposal wells, springs and other groundwater discharge areas, and locations of traditional groundwater use[2] in the assessment area and provide a map indicating their locations.

54) Discuss effects on receptors (e.g., nonindustrial water wells, springs and other groundwater-dependent ecosystems, locations of traditional groundwater use, and surface water bodies) resulting from the project, including an evaluation of changes to

a) groundwater quality from thermally mobilized constituents[3] and developing bitumen in contact with nonsaline groundwater[4] from in situ operations, and

b) groundwater quantity (e.g., drawdown resulting from use or dewatering, pressure build-up resulting from disposal, or other changes to natural flow conditions).

55) Summarize planned measures to mitigate effects and any anticipated short-term and long-term effects remaining after mitigation.

6.3 Reservoir Characterization

56) Discuss each target reservoir, including

a) the depositional environment;

b) mineralogy, grain size, and clay content;

c) porosity;

d) vertical and horizontal permeability;

e) facies association;

f) water, gas, and lean zones associated with the bitumen;

g) permeability barriers and baffles (e.g., tight streaks and shales); and

h) for a carbonate reservoir, the fracture analysis that includes the distribution, size, orientation, and density of the fractures.

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[2] See the definition of “traditional use” in appendix 1.

[3] For guidance, see the Government of Alberta’s (GoA’s) *Directive for the Assessment of Thermally-Mobilized Constituents in Groundwater for Thermal In Situ Operations*.

[4] For guidance, see the GoA’s *Directive for the Assessment of Non-Saline Groundwater in Direct Contact with Bitumen for In Situ Operations*.

57) For each target reservoir, provide the following maps and discuss the criteria used to define pay:

a) gross bitumen pay isopach

b) net bitumen pay isopach

c) net/gross bitumen pay ratio

d) structure map of top and base of net bitumen pay

e) top-water isopach (include identification of top water in contact with the target reservoir)

f) bottom-water isopach (include identification of bottom water in contact with the target reservoir)

g) lean zone isopachs associated with the target reservoir

h) pool isopach for all associated and nonassociated gas pools within the target reservoir

Also provide a summary of the data and analysis used to determine pooling (e.g., pressure and fluid contacts) for item (h).

58) For each target reservoir, provide

a) average bitumen viscosity,

b) initial gas-oil ratio,

c) initial pressure, and

d) initial temperature.

6.4 Resource Recovery Process

59) Describe the bitumen recovery process, including a description of any injection fluids and their composition.

60) Discuss the expected recovery performance and how it was determined. Provide the steam-oil ratio if applicable.

61) Provide a net pay map of the project's development area with well pattern trajectories and annotated drainage patterns (including approved but not drilled wells).

62) Describe the criteria used to determine the well placement relative to thief zones.

63) Provide the parameters below for the development area, and include the expected variation for each parameter and the basis for this variation:

a) vertical placement of horizontal wells or the perforation interval of vertical wells

b) interwell spacing

c) horizontal well length

d) buffers between drainage patterns

e) setbacks from project boundaries

64) Provide an annotated well log cross-section for each drainage pattern, including logs within and offsetting the pattern, that illustrates

a) the pay top and pay base,

b) facies distribution,

c) fluid contacts, and

d) the vertical placement of horizontal wells or the perforation interval of vertical wells.

65) Describe the operating strategy for the project. Include expected range of injection rates and injection volumes, injection and production durations, and bottomhole pressures and temperatures on a typical well or well pair and drainage pattern.

a) For steam-assisted gravity drainage (SAGD) projects, provide the above for start-up operations, normal operations, and wind-down operations.

b) For cyclic steam stimulation (CSS) projects, provide the above for a typical cycle, specifying each phase: injection, soaking, and production.

For dilation pressure CSS projects, also include maximum injection volumes above fill-up and dilation pressures on a cycle-by-cycle basis, as well as mitigation to eliminate the risk of fluid containment within the injection formation due to liner failures.

66) Discuss how geological factors (e.g., thief zones, structural events, incising channels) affect the operating strategy.

67) If associated gas is present, provide

a) the impact of associated gas to any overlying or underlying resource development,

b) identification of any associated gas pools that will or may have to be repressured in order to recover the bitumen,

c) the fluids that are planned for repressurization, and

d) any resource conservation or operational impacts associated with the fluid to be injected and how these could be mitigated.

68) Discuss the effects of the project on other energy resource recovery operations in the project area. Include

a) a summary of other operations in the area that could impact the project or could be impacted by the project,

b) identification of any surface or subsurface conflicts that may have implications on the development of the project or on the development of other operations, and

c) a summary of protocols and agreements in place to ensure the safe drilling and operation of wells.

69) Discuss plans for artificial lift.

70) Discuss the reservoir monitoring program. Include

a) the strategy in the placement of observation wells and the planned number of observation wells per drainage pattern,

b) the type of monitoring data to be collected,

c) the approximate interval depths at which monitoring data will be collected,

d) the frequency of monitoring data collection,

e) plans for 4-D seismic data collection, and

f) plans for surface-heave data collection.

6.5 Reserves

71) For both the project area and development area, provide the following and include all inputs used in the calculations:

a) the original bitumen in place (OBIP) (see figure 1)

b) the developable bitumen in place (DBIP) (see figure 1), and

c) the expected ultimate recovery factor.

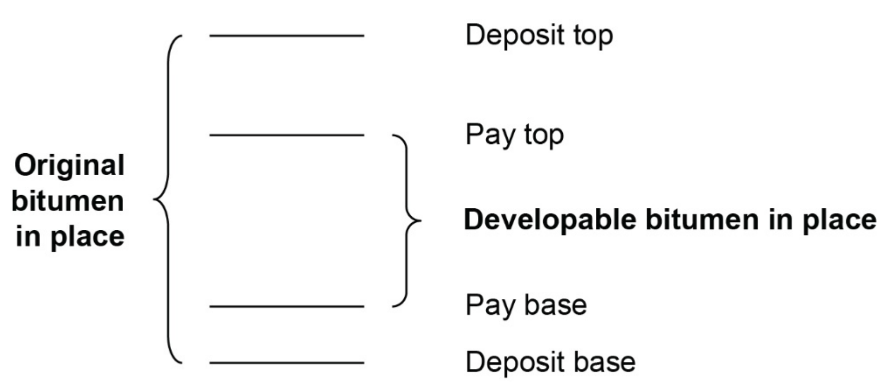


Figure 1. Reserve intervals

72) Demonstrate that the DBIP in the project area can support the applied-for production capacity for the duration of the project.

73) Discuss the methods used to determine the expected ultimate recovery factor (e.g., model study, a comparison of analogous projects).

74) Discuss how thief zones (i.e., transition zones, top gas, lean zones) may impact bitumen recovery in the development area.

75) Provide an annual production forecast for the life of the project, including assumptions and parameters used to determine the forecast.

76) Provide a table with the following information for each drainage pattern within the development area:

   a) drainage area (hectares)

   b) average net bitumen pay

   c) average porosity

   d) average water saturation

   e) volume of DBIP

   f) expected ultimate recovery factor

   g) volume of OBIP

6.6 Reservoir Simulation

Reservoir simulation may be required. Applicants are encouraged to discuss with the AER before submitting an application whether that is the case for their project.

77) If reservoir simulation is required, the following must be provided:

   a) the modelling and simulation software (version and model) used

   b) the input data and source, data filtering, and wrangling and modelling methodology (e.g., kriging, MPS) used to generate the model

   c) a discussion of the assumptions (e.g., homogeneous reservoir, dead oil), model variables (e.g., rock and fluid properties), and model parameters (e.g., anisotropy, mean variogram range, net-to-gross ratio and dead oil) used

   d) a summary of the relevant results of the simulation and how they support the reservoir development strategy

6.7 Existing Wells in the Project Area

The AER expects that all wells penetrating the target formation or deposit in the project area be completed or abandoned in a manner that is compatible with proposed in situ operations.

78) Cement and casing must be designed to withstand anticipated operating temperatures and pressures to ensure reservoir fluid containment.

79) Discuss the criteria used to assess the thermal compatibility of existing wells in the project area.

80) Provide a list of all existing wells that penetrate the target deposit and are within 300 m of a SAGD development area or 1000 m of a CSS development area. Discuss whether or not these wells are thermally compatible.

    Applicants may use the form available on the *Directive 023* webpage.

81) Provide a map of the project area and development area showing the drainage pattern boundaries and the locations of wells that are not thermally compatible.

82) Discuss the planned mitigation measures to ensure fluid containment (e.g., remediation, monitoring, buffer distances) for the wells that are not thermally compatible.

6.8 Well Operation, Design, and Drilling Practices

83) Provide a general wellbore schematic illustrating the completion design for all well types associated with the project. Include production, injection, observation, disposal, and water source wells that penetrate the caprock of the target reservoir within the project area.

84) Identify any site-specific issues that may lead to challenges in obtaining adequate cement bonds during the drilling and completion of the project wells. Provide the mitigations that will be incorporated into the drilling practices to ensure that cement bonds are compatible with thermal operations.

85) Provide a discussion on the operational monitoring systems proposed (e.g., passive seismic, thermal fibre, pressure monitoring in overlying zones, 4-D seismic) to assist in monitoring wellbore integrity.

6.9 Reservoir Containment and Maximum Operating Pressure (MOP)

If the project is within the shallow area set out in appendix 6 or if exceedances in MOP are being proposed, then additional requirements apply and the detail provided is expected to be proportional to the level of risk.

86) Operators must demonstrate in their application that reservoir fluid will be contained.

87) Identify the caprock and provide a data-supported discussion about its suitability and effectiveness in containing reservoir fluid (e.g., analogs, composition, cut-off criteria, lab analysis).

88) Provide the geological interpretation of the caprock, including

   a) structure maps of the top and base of the caprock in the project area that incorporate data from logs, core, and any seismic programs run;

   b) a map showing the depth of the base of the caprock in true vertical depth for the project area; and

   c) an isopach map of the caprock in the project area.

89) Provide an annotated depth-converted seismic section tied to well logs, illustrating the caprock, reservoir, and subcretaceous unconformity. The section should be indicative of erosional or structural anomalies in the project area.

90) Discuss the presence of water- and gas-bearing intervals within the caprock. Include an isopach map of these intervals.

91) Discuss any fractures, faults, karsts, incising channels, and structural collapse in the caprock or target reservoir and how these features may affect reservoir containment. Where features of significance are identified, provide

   a) core photos or image log results representative of identified structural features,

   b) a map illustrating where these features are located and when they occurred in relation to the reservoir deposition (pre-, syn-, or post-deposition), and

   c) a discussion of mitigations to ensure reservoir containment is not affected by these features.

92) Provide a summary of the results from all micro-fracture injection tests conducted in the project area. The testing summary must include

   a) the criteria used to determine the locations of the tests;

   b) the intervals in true vertical depth and zones tested; and

   c) the analysis of the test results, including

      i) the description and justification of the techniques used to analyze the data,

      ii) the estimated fracture closure gradient for all zones tested, and

      iii) the identification of any unexpected or unusual results and a discussion of possible causes.

93) If there are geological features such as faults, incising channels, or localized subsidence features that may potentially compromise caprock integrity, micro-fracture injection tests (or demonstrated equivalent) must be done in the vicinity of these features to investigate how these features may impact the fracture closure pressure gradient of the caprock.

All micro-fracture injection test data must be submitted in accordance with *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells.*

94) Provide a summary of the results of all geomechanical laboratory tests conducted to determine caprock properties within the project area (e.g., cohesion, friction angle, Young's modulus).

95) Provide MOP (bottomhole) in kilopascals gauge (kPag), calculated to avoid tensile failure of the caprock using the following formula:

$$0.8 \times g \times d$$

where 0.8 is the minimum safety factor, g is the caprock fracture closure gradient in kPag/m, and d is the true vertical depth in metres at the shallowest base of the caprock.

a) The lowest valid caprock fracture closure gradient obtained from representative micro-fracture injection tests must be used.

b) Surface topography must be considered in determining the depth at the shallowest base of the caprock.

The MOP may be determined for an entire development area, subareas within a development area, or on a drainage pattern basis. If the MOP is determined on a drainage pattern basis, it must be supported by a technical assessment that addresses how the MOP will be managed when steam chambers in different drainage patterns coalesce.

96) Discuss how operations will be monitored to ensure compliance with the proposed MOP, including details of how the bottomhole pressure will be determined and corrected for bottomhole temperature, pressure, and depth.

97) Discuss how operations will be monitored to determine whether the integrity of the caprock has been compromised. Include the criteria that will be used to characterize events that may compromise caprock integrity (such as detecting deviations from expected or predicted operating conditions) and the field operating protocols for responding to such an event.

6.9.1 Exceedance of MOP

The AER will consider requests to exceed the MOP during certain operations, including start-up and maintenance. However, additional information is required.

98) To request an increase in MOP above what is calculated in sections 6.9 or 6.10, provide

a) a discussion of the objectives and timing of the proposed MOP exceedance and, if approved, how the success of the increase would be determined;

b) the proposed bottomhole pressure, injection rate and volume, and duration of the exceedance;

c) a risk assessment (e.g., geomechanical modelling);

d) a caprock integrity monitoring plan; and

e) a response plan in the event an abnormal pressure response or fracture is detected.

Geomechanical modelling may be required. Applicants are encouraged to discuss with the AER before submitting an application whether that is the case for their project.

99) If modelling is required, provide

a) the modelling software (version, and model);

b) the input data and source, data filtering, and wrangling and modelling methodology (e.g., kriging, MPS) used to generate the model;

c) a summary of the modelling results, including sensitivity analyses of the main geomechanical and geological properties (e.g., fracture closure pressure gradient of the caprock, permeabilities of geological features);

d) an explanation of how the results support the requested MOP;

e) a discussion of the assumptions of the model (e.g., boundary conditions, material failure criteria, soil constitutive models); and

f) a summary of the parameters (e.g., material properties) used to generate the model.

6.10 Shallow Area

SAGD projects may face higher operational risks where the depth of the reservoir is 150 m or less and the geological setting could impact caprock integrity, potentially resulting in a loss of reservoir containment of injected steam and heated reservoir fluids.

This section sets out the information that must be provided as part of an application for an approval to construct and operate an oil sands in situ project within the shallow area shown in appendix 6.

6.10.1 Caprock Criteria

100) Demonstrate that the caprock is

a) at least 10 m thick,

b) composed of clay-rich bedrock, with a gamma-ray value greater than 75 API units, and

c) laterally continuous across the project area.

The lower Clearwater shale is the deepest caprock overlying the Wabiskaw-McMurray deposit that meets the above criteria. An applicant may request in their project application to calculate the MOP at the base of another geological unit provided that the lower Clearwater shale is present and meets requirement 100 or an equivalent caprock is present that will contain injected steam and heated reservoir fluids as effectively, as determined by a pilot.

6.10.2 Risk Assessment and Management Plan

101) Complete a risk assessment and management plan regarding reservoir containment and provide the following:

a) any assumptions used in the assessment and the uncertainties associated with them

b) a description of the pathways by which reservoir containment could be lost and the potential receptors

c) the likelihood and consequence of loss of reservoir containment for each of the pathways

d) a discussion of how the risks would be mitigated

e) a discussion of why the assessed level of risk and the risk management plan should be considered acceptable

6.10.3 Monitoring Program

To confirm reservoir containment, additional monitoring may be necessary, proportional to the level of risk.

102) Monitoring data must be used to calibrate and update the geomechanical model, discussed in section 6.10.6.

6.10.4 Seismic Data

103) Three-dimensional seismic data (or demonstrated equivalent as outlined in appendix 5) must be acquired for the entire development area and incorporated into the geological interpretation.

6.10.5 Hydrogeology

In order to assess the caprock integrity, where aquifers are present above and below the caprock within the development area, applicants must acquire hydrogeological data to determine whether the caprock hydraulically isolates the reservoir.

Aquifers to be assessed may include water sands in contact with the bitumen reservoir (i.e., top or bottom water), aquifers between the reservoir top and base of the caprock, and the deepest overlying aquifers (including any identified bedrock or incising channel aquifers).

104) At a minimum, assess the deepest suitable aquifer overlying the caprock and the shallowest suitable aquifer underlying the caprock and provide the following information:

  a) a map with the locations of observation wells, aquifer tests, drillstem tests, and sampling locations

  b) lithologs with completion details for each observation well or test hole

  c) isopach and structure maps for each aquifer

  d) potentiometric surface maps in metres of freshwater equivalent head above sea level

  e) plots of representative pressure head measurements versus depth and representative pressure head measurements versus elevation with comparisons to hydrostatic pressure and an assessment of hydraulic communication between aquifers

  f) representative laboratory analyses of groundwater from each aquifer and an interpretation of water chemistry differences between aquifers

6.10.6 Geomechanics

There are two mechanisms by which a caprock can fail, leading to a loss of containment: tensile and shear.

105) To address potential shear failure of the caprock leading to a loss of containment, geomechanical modelling must be conducted and the information specified in requirement 99 submitted.

106) Provide the frequency that the model will be updated with the results from the project's monitoring program.

107) If shear failure is indicated by the model, a plan to address the risk of shear failure must be submitted for review.

108) Applicants must perform a minimum of one representative micro-fracture injection test (or demonstrated equivalent) in the caprock for every four sections of the proposed development area to calibrate their geomechanical model and inform the AER's application review.

109) Before steaming, the micro-fracture injection test density in the caprock must be increased to a minimum of one for every two sections of development area that includes drainage patterns.

The approved MOP may be reduced based on new test results before steaming.

6.11 Water Sourcing

Water sources are classified as high-quality nonsaline, alternative nonsaline, saline, or produced water under the Government of Alberta's *Water Conservation Policy for Upstream Oil and Gas Operations* and the AER's *Directive 081*.

Surface water and nonsaline groundwater sourcing require *Water Act* licences. Saline groundwater sourcing does not require a *Water Act* licence.

The AER recommends that *Water Act* applications be submitted in parallel with *Directive 023* applications if the information required for the *Water Act* applications is available or if the project

- requires certainty on water sourcing,
- proposes using high-quality nonsaline water,
- is expected to affect other water users given the proposed water source, or
- is anticipated to have a high water use intensity or total water demand.

The AER may require that *Water Act* applications directly related to an oil sands project be submitted in parallel with the *Directive 023* application.

110) If *Water Act* applications are being processed in parallel, provide references to the active applications and any information listed in the next requirement that has not been included in the parallel *Water Act* applications.

If a *Water Act* application is not presently required for the project, the requirement below in its entirety must be followed.

111) For each make-up water source, provide

a) the water source classification;

b) for surface water sources, the water body names;

c) for groundwater sources,

i) the formation names, true vertical depths (TVDs) to the static (nonpumping) water levels, and TVDs to the aquifer tops, and

ii) the TDS concentration determined using the method described in *Groundwater Information Letter 1/2010*;

d) the points of diversion or wells, including the unique well identifiers (UWI) and, if available, facility numbers (i.e., ABWS); and

e) the average and maximum withdrawal rates per water body or aquifer and per well in m^3/d.

6.12 Disposal, Including Cavern Disposal, and Cavern Storage Schemes

In order to receive approval under the *Oil and Gas Conservation Act*, section 39, schemes for disposal or for cavern storage must adhere to *Directive 065: Resources Applications for Oil and Gas Reservoirs* and *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements*. Class Ib disposal schemes and cavern disposal schemes must also comply with *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry.*

The AER may require that applications for disposal schemes or cavern storage schemes directly related to an oil sands project be submitted in parallel with the *Directive 023* application.

112) If scheme applications are being processed in parallel, the next requirement does not apply, but references to the active scheme applications must be provided.

113) For each scheme, provide

a) the formation name and depth to the base of the overlying confinement strata for each well;

b) the number and locations of wells, including the UWIs and facility numbers (i.e., ABIF or ABWP);

c) the characterization of the disposal or storage zone, as well as isopach maps showing the extent of the zone and confining strata;

d) a discussion of the water disposal for the project and how it complies with the associated *Directive 081* maximum water disposal limit for the project; and

e) the average and maximum injection rates in m^3/d per formation and well.

6.13 Facilities

114) Describe the CPF and pad facilities.

115) Provide a plot plan of the CPF and each pad that includes

a) process equipment,

b) storage areas,

c) emergency relief stacks,

d) buildings, and

e) pipelines.

116) For each major process unit, describe the unit, its components, and its capacity and provide the associated simplified process flow diagram (PFD). PFDs must include enough detail so that all unit components can be easily identified.

117) For the entire project and for each phase of the project, provide a material balance for water, sulphur, and hydrocarbons (i.e., gas, bitumen, and diluent).

a) The material balances must be shown on a block flow diagram using both mass and volumetric flow rates.

b) All flow rates must be expressed on a calendar-day basis at standard temperature and pressure. Include the assumed facility service factor.

118) Provide a table listing each storage tank, including its

a) capacity,

b) contents,

c) roof type (e.g., floating, fixed), and

d) fugitive emissions control.

In situ oil sands projects must comply with *Directive 055: Storage Requirements for the Upstream Petroleum Industry*.

119) Provide an energy balance for the CPF. Include the lower heating value (LHV) and energy content of each stream.

120) Describe the storage, handling, and disposal of waste. Include

a) a list of the oilfield wastes that will be generated by the project (see *Directive 058* for general oilfield waste types),

b) the volumes to be generated,

c) the volumes to be stored on site,

d) the final disposition of the waste, and

e) any environmental controls.

Waste and storage management for in situ projects must comply with the requirements of *Directive 055* and *Directive 058.*

121) Describe the gathering and distribution pipelines between the CPF and well pad facilities.

7 Mining Applications

This section describes the information that must be provided as part of an application for an approval to construct and operate an oil sands mining operation, including an extraction plant.

The AER acknowledges that the level of detail and site-specific data to support the analyses for some requirements may not be available for new projects at the time of application. In these cases, the information available at the time of application submission must be provided. The necessary details must be submitted with an amendment application as per section 9 of this directive.

122) The applicant must submit a concordance table that references where each requirement in this directive is addressed in the application.

7.1 Geology and Resource Evaluation

123) Provide an overview of the geology in the surface mineable area, including

a) the topography,

b) the stratigraphy,

c) the depositional setting, and

d) any regional geological structures or features.

124) Provide a geological description of the project area for the Quaternary, Cretaceous, and Devonian periods. Include the following information for each formation, member, or unit identified:

a) a stratigraphic column

b) structural cross-sections

c) isopach and structure maps

d) the lithology

e) a map and cross-sections of water-bearing units

Also provide the data sources used (e.g., seismic, electromagnetic).

125) Describe the drilling activities done in accordance with *Directive 082: Operating Criteria: Resource Recovery Requirements for Oil Sands Mine and Processing Plant Operations*. Include

a) the drilling history and well abandonment practices;

b) a map of drillhole locations with an overlay of the lease boundaries, pit limit outlines, and surface facilities; and

c) a drillhole inventory table similar to appendix 8, indicating

i) the number of drillholes,

ii) drilling dates,

iii) the quality of the drillhole data,

iv) the laboratory analyses completed,

v) types of logs run, and

vi) facies described.

126) Corehole data must be submitted electronically as set out in appendix 3.

127) Discuss the core sampling and lab analysis methods for

a) bitumen, water, and solids;

b) particle-size distribution; and

c) clay characterization.

128) Explain how the block model was developed. Include

a) a description of the data and the data conditioning that was applied;

b) the block size and method of block modelling;

c) anisotropic assumptions;

d) model constraints (e.g., surfaces, facies);

e) compositing logic;

f) the validation process;

g) how modelling parameters were defined, including the cut-off for weight per cent bitumen, minimum thickness, and dilution; and

h) the calculation and methodology for total volume to bitumen-in-place ratio (TV:BIP).

129) Provide representative cross-sections that show the variability and distribution both vertically and laterally across the project area for

a) the mineable resource,

b) overburden and interburden,

c) resource–water sands contacts, and

d) top of the Devonian.

130) Provide maps for

a) TV:BIP for values up to 18:1 overlain with drillhole locations,

b) total mineable resource thickness,

c) weight per cent bitumen starting at 5 per cent,

d) total interburden thickness,

e) total overburden thickness, and

f) fines distribution.

131) Provide a table of mineable resources, including

a) tonnage of resource, fines, interburden, and overburden;

b) per cent average fines;

c) weight per cent bitumen; and

d) total bitumen volume.

7.2 Mine Design

While *Directive 082* sets out the minimum requirements for resource recovery, the applicant must describe the design of the mine as it will be operated.

132) Summarize the objectives of the mine's design and the mining method. Include which mining technologies will be used (e.g., truck and shovel, slurry at face) and the rationale for the mining method selected.

133) Discuss the assumptions of the mine's design. Include

a) the production rate;

b) bitumen recovery;

c) per cent material suitability for construction; and

d) densities used in the mine's material balance for mineable resource and waste, bitumen, and storage and disposal structures, including for tailings.

134) Discuss the slopes for all

a) pits,

b) storage structures, and

c) disposal structures.

135) Discuss the design criteria and constraints for setbacks from water bodies, infrastructure, and lease boundaries.

136) Provide a map of the project area that includes

a) the project footprint, including the ultimate pit limits, extraction and processing plants, storage and disposal structures (including for tailings), and sedimentation and emergency ponds; and

b) watercourses, stream diversions, compensation lakes, utility corridors, and any other relevant features.

The digital spatial data for the features listed in (a) and (b) must be submitted electronically as stated in appendix 2.

137) Describe how the project area will be developed and discuss cooperative efforts with adjacent operators. Include plans for integrating the project with adjacent operations specific to each lease boundary.

138) Describe the mine pit limit analyses. Include

a) the methods used;

b) analysis factors, such as waste island evaluation and pushbacks, as well as operational and economic considerations;

c) maps showing stages of analysis for each pit; and

d) a table of waste volumes, mineable resource volume, weight per cent bitumen, recoverable mineable resource volume, and TV:BIP for each pit and stage of analysis.

139) Discuss how the mine design meets or exceeds the requirements of *Directive 082*. In cases where a variance to a *Directive 082* requirement has been approved, discuss how the approval conditions will be met.

140) Justify any sterilization of mineable resources or disposal of recovered resources. Include

a) a map that identifies the location of the resources proposed for sterilization or disposal and shows the unmined areas, storage locations, and plant site footprint; and

b) a description of options for minimizing or eliminating resource sterilization or disposal, such as moving infrastructure, revising project scheduling, modifying project setbacks, or blending feed.

The digital spatial data for the features listed in (a) must be submitted electronically as stated in appendix 2.

141) Provide the mass and weight per cent bitumen of the mineable resources to be sterilized or disposed of.

If a stockpile is being considered for sterilization, include the original characteristics of the stockpile and describe the original plan for its use.

142) Provide an economic evaluation for each area containing mineable resources that will be sterilized or disposed of. Include data on an incremental basis, detailing any simplifying assumptions used.

For the economic evaluation, use the following:

- a sensitivity analysis to assess risk or error
- an appropriate discount rate; include a justification of its applicability
- the lesser of 25 years or remaining project life as the time span of study, with the sterilized resource valued in the period in which it would have been recovered (in the case of an amendment, according to the previously approved mine plan)

143) Provide a table of the mineable recoverable resources for the project area, including

a) tonnage of recoverable resources, fines, interburden, and overburden;

b) per cent average fines;

c) weight per cent bitumen; and

d) recoverable bitumen volume.

144) Discuss the design of the shovel bench, including the criteria used to determine

a) the bench width,

b) the bench height, and

c) the need for and design of double or triple benches.

145) Discuss operational practices needed at the mine face to maintain a safe working environment.

146) Discuss the design of haul roads and ramps. Include

a) road gradients,

b) surface running width for single- and double-lane traffic,

c) berms, and

d) emergency escape routes.

147) Provide a map showing hydrological and hydrogeological interventions. Include well locations, dewatering ditches, and diversion routes.

148) Provide a table of water withdrawal rates for each depressurization well.

149) Discuss the release of water into each mine pit from water-bearing units around the pit and identify the confining units preventing upwards movement of water into the pit. Include the stability of water-bearing units below the pit, the ability of the confining units to prevent upwards movement of water into the pit, and potential weaknesses in the confining units.

7.3 Geotechnical Design

This section sets out the required geotechnical information for each final pit wall and disposal and storage structure with an overall height of 5 m or greater. In these cases, provide the information available at the time of submitting the application, with details to be provided at a later date in accordance with sections 24 and 24.01 of the *OSCR*.

7.3.1 Pit Wall Design

150) Provide a predevelopment topographic map of the pit wall location showing pit limits, surface runoff and drainage systems, and surrounding infrastructure.

151) Discuss the characteristics of the pit wall area. Include surface topography, surficial and bedrock geology, geological formation history, and representative geological profiles or models.

152) Provide geological profiles for the pit wall area showing bench widths and elevations, toe, crest, interbench angles, and overall slope angle.

153) Provide site characterization results. Include soil and rock properties, groundwater elevations, and field and laboratory test data.

154) Provide a summary of the design parameters, including strength, pore water pressure, and pit wall geometry, and discuss the basis for parameter selection.

155) Provide the design criteria for the pit wall and discuss the failure mechanisms that are addressed using these design criteria.

156) Describe the stability analysis of the pit wall at selected critical locations. Include

   a) assumptions;

   b) uncertainties or anticipated risks associated with the design, such as bench-slope failure and shallow- or deep-seated failure;

   c) consequences of pit wall failure for different failure mechanisms and remedial measures; and

   d) representative cross-sections, maps, and graphs illustrating the results of the stability analysis.

157) Provide an assessment, including assumptions, of the interaction between the pit wall and adjacent structures.

158) Discuss dewatering, depressurization, and surface runoff diversion activities to maintain the stability of the pit walls and adjacent structures.

159) Provide the configuration for the final pit wall based on the stability analysis.

160) Describe the monitoring plans for groundwater (pore water pressure) and ground deformation in the vicinity of the pit wall. Include

   a) a map of the monitoring locations,

   b) geological cross-sections showing target depths,

   c) monitoring types and purposes,

   d) method and timing for installing monitoring equipment, and

   e) monitoring frequencies.

7.3.2 Storage or Disposal Structure Design

This section does not apply to dams that meet the criteria set out in Part 27(1) of the *Water (Ministerial) Regulation* or to any other fluid-retaining structures.

161) Describe each storage or disposal structure. Include

   a) a topographic map that shows the footprint, surrounding infrastructure, and drainage systems (e.g., ditches, adjacent water bodies) associated with the structure;

   b) a table of construction start and completion dates, and, if applicable, depletion dates;

   c) timelines for placement of different materials within the structure; and

   d) representative cross-sections showing bench widths and elevations, toe, crest, interbench angles, and overall slope angle.

162) Discuss conditions before initial material placement. Include

   a) surface topography;

   b) surficial and bedrock geology;

   c) soil and rock properties;

d) groundwater elevations and piezometric surfaces; and

e) geological profiles or models.

163) Provide representative cross-sections, tables, and graphs of the data collected.

164) Provide site characterization results. Include soil and rock properties, groundwater elevations, and field and laboratory test data.

165) Discuss the preparation required for each storage or disposal structure's foundation. Include clearing, drainage, and ground preparation.

166) Provide a summary of the design parameters, including strength, pore water pressure, and geometry of the storage or disposal structure, and discuss the basis for parameter selection.

167) Provide the design criteria for the storage or disposal structure. Discuss the failure mechanisms that are addressed using the specified design criteria.

168) Discuss the construction material specifications and lift placement procedures for each storage or disposal structure, including the density and thickness of the lift and seasonal considerations for operations.

169) Discuss the stability analysis, based on measured conditions, for the foundation and fill in each storage or disposal structure. Include

a) assumptions;

b) anticipated risks or uncertainties associated with the design, such as shallow- or deep-seated failure;

c) consequences of slope failure for different failure mechanisms and remedial measures; and

d) representative cross-sections, maps, and graphs illustrating the results of the stability analysis.

170) Provide an assessment of the interaction between each storage or disposal structure and existing or future adjacent structures. Include the assumptions made and any associated risks or uncertainties.

171) Discuss the final geometric and drainage design for each disposal or storage structure. Include

a) overall dimensions;

b) representative cross-sections;

c) a figure illustrating the drainage areas;

d) a table showing the size, slope, and maximum overland flow path lengths for each drainage area; and

e) construction activities needed to define the drainage areas.

172) Describe the monitoring plans for groundwater (pore water pressure) and ground deformation in the vicinity of the storage or disposal structure. Include

a) a map of monitoring locations,

b) geological cross-sections showing target depths,

c) monitoring types and purposes,

d) method and timing for installing monitoring equipment, and

e) monitoring frequencies.

173) If frozen or treated tailings are deposited within the storage or disposal structure, include the following additional information:

Settlement information

a) Provide the locations of the frozen or treated tailings deposits and their depth profiles.

b) Discuss how settlement affects the life-of-mine closure plan.

c) Outline closure timelines such as end-of-mine life, reclamation capping, and reclamation, as they relate to the consolidation timeline.

d) Provide the consolidation model (if frozen material is deposited, the thaw consolidation model). Include the following:

- assumptions and limitations
- model parameters
- model calibration
- settlement prediction (90% of consolidation)

Also provide

- the settlement monitoring and validation program or plan to validate the consolidation model, and
- the contingency plan in the event that the settlement predicted by the consolidation model varies from the actual settlement.

Strength and trafficability information

e) Provide the

i) analysis of the liquefaction potential,

ii) assessment of the bearing capacity for capping and next-use landform, and

iii) plan to monitor the performance of the frozen or treated tailings deposit.

7.4 Mine Plan

174) Provide a table showing mineable recoverable resources, stockpiled resources, weight per cent bitumen, and bitumen production for each of the mine's first 10 years and for 5-year mining intervals thereafter.

175) Describe the mine development. Include all the following information:

a) A mine sequence map showing the mining area for each year of the mine's life.

b) A mine development map showing for each of the mine's first 10 years and for 5-year mining intervals thereafter

i) the preparation, mining advance, disposal and storage areas and structures, including for tailings, and reclamation activity;

ii) any surface facilities, water bodies, and utilities; and

iii) the project area.

c) A description of activities for each of the first 10 years and for 5-year intervals thereafter.

176) Provide a material balance for each of the mine's first 10 years and for 5-year intervals thereafter for reclamation, overburden, interburden, and crusher rejects. Include source, material type, and destination.

177) Provide a table of overburden and interburden classified by

a) geological formation with associated volume and weight,

b) per cent of material suitable for construction, and

c) the amount for use in storage and disposal area construction.

178) Discuss the circumstances under which blasting will be required and the operating procedures to ensure safe blasting. Include

a) the criteria used to define the need for blasting,

b) which material types will require blasting, and

c) when in the mine plan sequence blasting will occur.

179) List the mine equipment for each project development phase.

180) Discuss how the assumptions used in developing the mine plan align with

a) current approvals under *EPEA*, *OSCA*, and the *Water Act*;

b) the tailings plan;

c) the water management plan;

d) the mine reclamation plan; and

e) the life-of-mine closure plan.

181) Identify inconsistencies between the mine plan and current approvals. Where there are inconsistencies, describe how the plan will be aligned with the approvals.

7.5 Extraction Plant

182) Describe the extraction plant, including overall and per train production capacity.

183) Discuss the criteria for selecting the process technology.

184) Provide a plot plan of the extraction plant that includes

a) process equipment,

b) storage areas,

c) emergency relief stacks,

d) buildings, and

e) pipelines.

185) For each major process unit, describe the unit, its components, and its capacity and provide the associated simplified PFD. PFDs must include enough detail so that all unit components can be easily identified.

186) Describe the utilities and infrastructure associated with the extraction plant. These could include water, cogeneration, steam, electricity, and pipelines.

187) For the entire project and for each phase of the project, provide a material balance for solids, water, and hydrocarbons (i.e., bitumen, solvent, and diluent).

a) The material balances must be shown on a block flow diagram using both mass and volumetric flow rates.

b) All flow rates must be expressed on a calendar-day basis at standard temperature and pressure. Include the assumed facility service factor.

188) Provide a table listing each storage tank, including its

a) capacity,

b) contents, and

c) roof type (e.g., floating, fixed).

189) Provide an energy balance for the extraction plant and mine operations. Include the LHV and energy content of each stream.

Appendix 7 provides a generic energy balance. Adapt the energy balance as necessary to reflect the project.

190) Provide a simplified PFD showing the measurement points and the measurement device (e.g., meter, sampler) within the extraction plant to be used for mass balancing, assessing regulatory compliance, and fulfilling the reporting requirements of the AER.

191) Describe the actions that will be taken to minimize feed and product losses during commissioning and start-up.

192) Describe how the extraction plant's design can accommodate the expected range in ore quality. Provide and justify the quality of the ore that the design was based on.

Parameters used to determine the quality of the ore include bitumen, connate water quality, fines content, and d50 sand grain size.

7.6 Tailings Management

This section sets out the required information for each new or amended tailings deposit, tailings storage and disposal area, and tailings technology. This information is required regardless of whether the same information will be provided under *Directive 085*.

193) For each element covered in the tailings management plan, such as a tailings treatment facility or a tailings storage or disposal structure, provide a table of planned key construction, operating, abandonment, and closure activity dates.

194) Provide a description of each tailings treatment facility and its capacity. Include a simplified PFD for each treatment facility with sufficient detail to discern the equipment being proposed.

195) For each tailings storage and disposal structure, provide

a) its capacity and contents, and

b) how it will be managed during each phase of the mine plan.

196) Describe the construction and operation of each tailings storage and disposal structure. Include

a) a table that shows the volume placed and corresponding elevation for each tailings storage and disposal structure for each of the mine's first 10 years and for 5-year intervals thereafter,

b) a description of the types of material used for construction, and

c) a list of tailings types being deposited within each structure or being used in the construction of the structure.

197) Provide a measurement plan that describes the methods used to characterize and determine the volume of all coarse sand structures, including beaches.

198) Provide a table showing total fluid tailings volume accumulating in tailings storage and disposal structures for each of the mine's first 10 years and for 5-year intervals thereafter.

199) Provide a graph that shows each structure's tailings containment and storage capacity for each of the mine's first 10 years and for 5-year intervals thereafter.

200) Provide the design for each structure and deposit. Include

a) design assumptions, and

b) geometry (e.g., height, slope of base).

7.7 Water Management

201) Describe the storage, handling, use, recycling, treatment, and disposal of water for the project. Include a summary of water management strategies to minimize the use of fresh make-up water and increase the recycling of process-affected water.

8 Processing Plant Applications

202) Describe the processing plant, including the overall and per train production capacity.

203) Discuss the criteria for selecting the process technology.

204) Provide a plot plan of the processing plant that includes

a) process equipment,

b) storage areas,

c) emergency relief stacks,

d) buildings, and

e) pipelines.

205) For each major process unit, describe the unit, its components, and its capacity. Provide the associated simplified PFDs for each unit. PFDs must include enough detail so that all unit components can be easily identified.

206) Describe the utilities and infrastructure associated with the processing plant. These may include water, cogeneration, steam, electricity, and pipelines.

207) For the entire project and for each phase of the project, provide a material balance for solids, water, sulphur, and hydrocarbons (i.e., process gas, bitumen, and diluent).

a) The material balances must be shown on a block flow diagram using both mass and volumetric flow rates.

b) All flow rates must be expressed on a calendar-day basis at standard temperature and pressure. Include the assumed facility service factor.

208) Provide a table listing each storage tank, including its

a) capacity,

b) contents, and

c) roof type (e.g., floating, fixed).

209) Provide an energy balance for the processing plant. Include the LHV and energy content of each stream.

Appendix 7 provides a generic energy balance. Adapt the energy balance as necessary to reflect the project.

210) Describe the following systems in the processing plant:

a) source water (e.g., water intakes)

b) storage water

c) recycling water

d) water handling (e.g., cooling water system, water treatment system)

e) water disposal (e.g., oily water sewer systems)

211) Describe the storage, handling, and disposal of waste (excluding tailings), including

a) the volumes to be generated, and

b) the volumes to be stored on site.

212) Describe the storage, handling, and disposal of by-products. Include

a) the mass of by-products to be stored on site, either temporarily as running inventory or as a result of emergency situations; and

b) the transportation of by-products off site.

213) Provide a simplified PFD showing the measurement points and the type of measurement device (e.g., meter, sampler) within the processing plant to be used for mass balancing, assessing regulatory compliance, and fulfilling the reporting requirements of the AER.

9 Amendment Applications

Amendment applications are required when an applicant proposes to modify an approved oil sands project unless an approval for the life cycle of the project has been granted (see section 9.1).

As part of the amendment process, applicants must follow the requirements in this directive and the applicable requirements under the specified enactments (e.g., *EPEA*, *Public Lands Act*, *Water Act*).

Directive 023 amendment applications fall under one of the three categories described below. The level of information provided in the amendment application needs to reflect the scale of the proposed modification.

214) The amendment application must include all the information required to support the requested project modification. If a proposed modification requires the support of information submitted previously (e.g., models, assessments, studies) to demonstrate how requirements will be met, that information must be submitted with the amendment application.

Upon initial review of an amendment application, the AER may recategorize the application and request additional information, if necessary.

Category 1 amendments are applications to optimize an oil sands project or replace or repair infrastructure in a way that will not result in a change to

a) resource conservation,

b) process flows, or

c) material balances.

Category 2 amendments are applications to modify an oil sands project in a way that may affect

a) resource conservation,

b) process flows, or

c) material balances.

Category 3 amendments are applications to modify an oil sands project that will affect at least one of the following:

a) the project area,

b) resource conservation,

c) process flows, or

d) material balances.

The *Directive 023* webpage contains a table with a nonexhaustive list of activities and the amendment categories that they fall under. The table also indicates which of the activities may qualify for a life-cycle approval, explained below.

9.1 In Situ Life-Cycle Applications

The AER may approve certain category 1 and 2 amendment activities for the entire duration of an in situ project, from construction to reclamation. Such an approval is referred to as a life-cycle approval.

Activities authorized under a life-cycle approval may not require future amendments to the scheme approval. Instead, the operator will submit updates through the *Directive 054*: *Performance Reporting and Surveillance of In Situ Oil Sands Schemes* process and an annual report as described in the *Directive 023* approval. For instance, an applicant receives a life-cycle approval for development areas that have not fully met the delineation requirements under this directive. Once the operator has conducted the necessary delineation prior to well and pad placement, they will inform the AER of this work on an annual basis or as instructed in the approval instead of submitting an amendment application.

A life-cycle approval is available for both new in situ schemes and existing schemes. Applicants are encouraged to discuss a life-cycle approval with the AER before making a request.

215) For a new in situ scheme, the applicant must include the request for a life-cycle approval in the application for the new scheme.

216) For an existing scheme, the applicant must submit at least a category 2 amendment application when requesting a life-cycle approval, regardless of the activities included in the application.

Only certain activities may be eligible for a life-cycle approval. Refer to the table on the *Directive 023* webpage for an indication of applicable activities.

217) If a life-cycle approval is granted, the approval holder must ensure that all applicable requirements throughout this directive are met.

The AER will require monitoring and reporting to confirm compliance with the directive throughout the life of the project. Any project-specific reporting will be done in accordance with *Directive 054*, with the performance reports published annually on the AER’s website.

10 Socioeconomic and Environmental Requirements for Small-Scale In Situ Projects

This section sets out the socioeconomic and environmental information to be provided for

- a new *OSCA* scheme application for a small-scale in situ project, or
- an amendment application to add new well pads to an existing small-scale in situ project.

10.1 Socioeconomic Requirements

Applicants must evaluate the location, setting, and duration of their operations to determine the extent of anticipated socioeconomic impacts. Larger activities often have impacts over a greater area and longer period of time than smaller activities. In the case of *OSCA* scheme amendment applications, the extent of the impacts depends on the spatial and temporal scales of the proposed changes.

218) Describe the assessment area and the criteria used to define it. The assessment area could include local and regional communities, and Indigenous communities.

219) Describe the existing socioeconomic conditions within the assessment area, including the following:

a) Population (permanent and transient)

b) Housing, including availability

c) Employment and training (potential employable population)

d) Economic activity

e) Transportation

f) Infrastructure and services (e.g., recreational services and public services such as sewage treatment, law enforcement, fire protection, education, and health services)

220) Provide information on the project's workforce, including

a) the number of direct jobs;

b) the timing of peak periods;

c) the transportation of workers and equipment to and from the site, including type, quantity, and frequency; and

d) worker accommodations, both off site and on site.

221) Discuss the potential negative and positive effects on the following:

a) Housing, including availability

b) Employment and training

c) Economic activity

d) Transportation

- Effects of transporting workers and equipment on traffic

e) Infrastructure and services

f) Indigenous communities

- Effects on traditional land use, including the use of culturally and traditionally important wildlife and plant species and access to sites containing them, as well as other sociocultural effects

222) Discuss the measures to eliminate or mitigate identified negative socioeconomic effects of the project and indicate any potential residual effects.

10.2 Environmental Requirements

10.2.1 Land Use

223) Identify and discuss the potential for using an existing project footprint.

224) Include a map illustrating any overlap between existing surface disturbance and the proposed project footprint.

225) Discuss the potential to share or use third-party infrastructure.

10.2.2 Vegetation and Wetlands

226) Describe the assessment area and the criteria used to determine it.

227) Identify vegetation and wetland types within the assessment area, specifying those that are locally or regionally rare or sensitive.

Vegetation types should be identified at the ecosite phase level or equivalent, using the Alberta *Ecological Land Classification* guides, the Alberta Wetland Classification System, or other similar standard.

Include a map illustrating the vegetation and wetland types overlaid with the proposed project area and any surface disturbance within the project area. Also include a table of the overall project area in hectares by ecosite type.

For the initial phase of development, identify in a map the locations of known rare plants and locations with high potential to support rare plants. Include a table of disturbance in hectares by ecosite type.

228) For the assessment area, identify vegetation species of management concern and culturally important vegetation species. Describe sites with the potential to support these species.

Include species listed as "At Risk," "May Be At Risk," and "Sensitive" under Wild Species: The General Status of Species in Canada; listed in Schedule 1 of Canada's *Species at Risk Act*; listed as "Special Concern," "Threatened," or "Endangered" by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC); and traditionally used species.

Identify rare ecological communities and vegetation species that support rare or culturally important wildlife species.

229) Summarize the vegetation information gathered in the assessment area and the collection methods. Also identify how the collection methods are appropriate for the scale of the project, site conditions, and the timing of development.

Sources of information may include baseline surveys, existing reports and assessments, and species observation data from systems such as the Alberta Conservation Information Management System.

Collection methods may include field and desktop surveys. Information from desktop surveys may be appropriate to describe baseline environmental conditions where adequate data exist. Field surveys, however, may be necessary to supplement the desktop information if it is insufficient to determine baseline environmental conditions.

230) Identify and discuss project effects on the vegetation and wetlands.

Include effects of potential acid input on vegetation and wetlands, where applicable.

231) Summarize planned measures to mitigate the project effects and any anticipated short-term and long-term effects remaining after mitigation.

232) For the initial phase of development, describe how the mitigations will be applied and identify anticipated short-term and long-term effects remaining after mitigation, noting changes in habitat quality and availability of suitable habitat for plants of concern (e.g., rare plants) and culturally important plant species (e.g., used in traditional foods and medicines). Include riparian areas.

Additional environmental requirements may apply to impacts on wetlands under the *Alberta Wetland Policy*.

10.2.3 Wildlife

233) Describe the assessment area and the criteria used to determine it.

234) Identify the presence or potential presence of rare, sensitive, or culturally important wildlife species' habitat or ranges within the assessment area.

Include a map illustrating known and potential locations of identified wildlife species overlaid with the project area, as well as any provincially or federally determined boundaries (e.g., caribou zones).

Also include a map of the high-quality habitats for the identified wildlife species overlaid with the project area.

Specify the criteria used to identify affected wildlife species and their habitat.

Include species listed as "At Risk," "May Be At Risk," and "Sensitive" under the Alberta Wild Species Status List; listed in Schedule 1 of Canada's *Species at Risk Act*; listed as "Special Concern," "Threatened," or "Endangered" by COSEWIC; and traditionally used species.

235) Summarize the wildlife information gathered in the assessment area and the collection methods. Also identify how collection methods are appropriate for the target species, scale of the project, site conditions, and timing of development.

Sources of information may include baseline surveys, existing reports and assessments, and species observation data from systems such as the Fish and Wildlife Management Information System.

Collection methods may include field and desktop surveys. Information from desktop surveys may be appropriate to describe baseline environmental conditions where adequate data exist. Field surveys, however, may be necessary to supplement the desktop information if it is insufficient to determine baseline environmental conditions.

236) Identify and discuss the effects of the project on the identified wildlife species. If focal species are used, explain the process for selecting focal species and describe how they represent the range of species that occur in the assessment area.

Effects could include mortality, sensory disturbance, and changes to wildlife health, movement, and habitat availability.

237) Summarize planned measures to mitigate these effects and any anticipated short-term and long-term effects remaining after mitigation.

For the initial phase of development, describe how the mitigations will be applied and identify anticipated short-term and long-term effects remaining after mitigation, noting changes in habitat quality and availability for rare, sensitive, or culturally important species.

10.2.4 Hydrology

Hydrology information must be provided under a *Water Act* application, if applicable.

Surface Water Quality

238) Describe the assessment area and the criteria used to determine it.

239) Identify water bodies within the assessment area

   a) that are sensitive to changes in water chemistry (e.g., changes in pH, salinity, nutrients), or

   b) with atypical water chemistry (i.e., water quality with parameters outside of the natural range of variation or exceeding the *Environmental Quality Guidelines for Alberta Surface Waters*).

   Specify the criteria used to identify these surface water bodies.

240) Include a map illustrating the project area and all water bodies within that area.

241) Provide baseline physical, inorganic, and organic water chemistry measurements for a representative water body; all water bodies sensitive to changes in chemistry; and those with atypical chemistry.

242) For water bodies with atypical chemistry, discuss the locations of these water bodies and any known factors contributing to their atypical chemistry.

243) Summarize the water quality information gathered in the assessment area and the collection methods. Also identify how collection methods are appropriate for the scale of the project, site conditions, and the timing of development.

   Sources of information may include baseline surveys and existing reports and assessments.

   Collection methods may include field and desktop surveys. Information from desktop surveys may be appropriate to describe baseline environmental conditions where adequate data exist. Field surveys, however, may be necessary to supplement the desktop information if it is insufficient to determine baseline environmental conditions.

244) Include a map showing the location of any field measurements obtained.

245) Identify and discuss the effects of the project on the water quality of the identified water bodies.

246) Summarize planned measures to mitigate effects and any anticipated short-term and long-term effects remaining after mitigation.

For the initial phase of the development, describe how the mitigations will be applied and identify anticipated short-term and long-term effects remaining after mitigation.

10.2.5 Fisheries

247) Describe the assessment area and the criteria used to determine it.

248) Identify fish-bearing and potentially fish-bearing water bodies in the assessment area. Specify the criteria used to identify these water bodies.

249) Identify the presence or potential presence of any rare, sensitive, or culturally important fish and their habitats within the assessment area.

250) Include a map of the habitat of fish species (with the fish species labelled) overlaid with the project area.

Include species listed as “At Risk,” “May Be At Risk,” and “Sensitive” under the Alberta Wild Species Status List; listed in Schedule 1 of Canada’s *Species at Risk Act*; listed as “Special Concern,” “Threatened,” or “Endangered” by COSEWIC; and traditionally used species.

251) Summarize the fisheries information gathered in the assessment area and the collection methods. Also, identify how collection methods are appropriate for the scale of the project, site conditions, and timing of development.

Identify and discuss the effects of the project on fish and their habitats.

Effects could arise from changes in hydrology (affecting quantity or availability of fish habitat), changes in surface water quality (affecting fish abundance and health), or changes in groundwater quantity or quality.

Sources of information may include baseline surveys and existing reports and assessments.

Collection methods may include field and desktop surveys. Information from desktop surveys may be appropriate to describe baseline environmental conditions where adequate data exist. Field surveys, however, may be necessary to supplement the desktop information if it is insufficient to determine baseline environmental conditions.

252) Summarize planned measures to mitigate effects and any anticipated short-term and long-term effects remaining after mitigation.

For the initial phase of development, describe how the mitigations will be applied and identify any anticipated short-term and long-term effects remaining after mitigation.

10.3 Air Quality and Emissions

253) Discuss the potential for odours both inside and outside the project's boundaries, possible causes, and mitigation strategies. Include an odour impact assessment and a plan to monitor odours to verify predictions of odour impacts and detect any unforeseen odour impacts after operations start.

Appendix 1 Definitions for the Purposes of *Directive 023*

assessment area	The area in which the socioeconomic or environmental effects are expected to occur and have been evaluated for the life of the project.
caprock	A succession of low-permeability and geomechanically strong strata that can effectively contain reservoir fluids.
central processing facility	See the *OSCR*.
culturally important	Places, settings or surroundings, activities, uses, and objects with aesthetic, traditional, ecological, social, or spiritual value for past, present, or future generations.
drainage pattern	A configuration of production and/or injection wells placed within the reservoir that will be operated in a unified manner to recover bitumen from a localized area.
original bitumen in place	The volume of crude bitumen calculated or interpreted to exist in the ground before any quantity has been produced.
developable bitumen in place	The volume of crude bitumen calculated or interpreted to exist in the target reservoir before any quantity of bitumen has been produced.
development area	The area where in situ oil sands resource recovery and associated surface infrastructure is expected.
Indigenous communities	Includes First Nation and Métis communities.
initial established reserves of bitumen	Established reserves prior to the deduction of any production. See *ST98: Alberta Energy Outlook* for further information on the AER's approach of reporting reserves.

initial development phase	The components of the project associated with the initial planned stage of construction, commissioning, and operation.
in situ gross bitumen pay	A target interval with no cutoffs applied.
in situ net bitumen pay	A target interval with specified cutoffs applied.
in situ operation	See *OSCA*.
lean zone	A zone associated with the target reservoir that has different reservoir properties and normally higher level of water saturation than the target reservoir.
major process units	A combination of process equipment designed to support the recovery or conversion of oil sands or oil sands products (e.g., oil treatment, water treatment, gas treatment, steam generation, distillation, coking, cracking, sulphur recovery).
mineable recoverable resources	Those resources that are discovered and potentially recoverable after applying mining constraints.
mineable resources	Those resources that are discovered and potentially recoverable before applying mining constraints.
mine site	See *OSCA*.
mining constraints	Factors that may prevent the recovery of oil sands, such as environmental setbacks; small, isolated ore bodies; and the locations of surface facilities (e.g., plant sites, tailings ponds, storage or disposal structures).
mining operation	See *OSCA*.
oil sands	See *OSCA*.
oil sands project	An in situ operation, a mining operation, a processing plant, or any one or more of them.
processing plant	See *OSCA*.
project area (in situ)	The area where oil sands resources exist and subsurface development may occur.
project area (mining or processing plant)	The boundaries within which surface development may occur over the life of the project.

project footprint	The area where physical surface disturbance resulting from resource recovery from an oil sands project occurs.
shallow area	Where the net bitumen pay in the Wabiskaw-McMurray deposit is greater than zero, the shallow area is the area in which the Clearwater caprock is less than 10 m thick or the base of the lower Clearwater shale (Wabiskaw marker) is shallower than 150 m.
small-scale in situ project	In situ projects with a production capacity of 2000 m^3 or less of crude bitumen per day.
sociocultural effects	Changes to social and cultural elements, including traditional land uses.
traditional uses	Activities, customs, or practices that Indigenous peoples pursued or are pursuing that are culturally important and involve the harvesting of Indigenous traditional resources such as wildlife and fish, gathering medicinal plants, and using water. May also include the use of burial grounds, gathering sites, and historical or ceremonial locations.
water body	See *Directive 056: Energy Development Applications and Schedules*.

Appendix 2 Spatial Information Submission Requirements

The AER will use spatial data to assist with the application review process. Below are the spatial submission requirements.

Submitted spatial information that does not meet the outlined submission requirements will be returned to the applicant. Failure of an applicant to provide the required information in the proper format may cause delays or complications in the processing of the application or may result in a decision by the AER to close the application.

Standards

The AER requires spatial data in the form of shapefiles that are supported by the Environmental Systems Research Institute (ESRI) ArcView products. Shapefiles will adhere to the following standards:

Shapefile format	Extension	Example
Main file (shape records)	.shp	example.shp
dBase table (attribute records)	.dbf	example.dbf
Index file	.shx	example.shx
Project file (map project and datum information)	.prj	example.prj

Note: A naming convention isn't required as long as the file name is supported by the ESRI shapefile standard. These spatial standards are outlined in the ESRI White Paper, ESRI Shapefile Technical Description.

Geodatum and Map Projections

All shapefiles must be in 10TM_AEP_FOREST projection. The following .prj file parameters must be adhered to:

PROJCS[“NAD_1983_10TM_AEP_Forest”,GEOGCS[“GCS_North_American_1983”,DATUM[“D_North_American_1983”,SPHEROID[“GRS_1980”,6378137.0,298.257222101]],PRIMEM[“Greenwich”,0.0],UNIT[“Degree”,0.0174532925199433\\,PROJECTION[“Transverse_Mercator”],PARAMETER[“False_Easting”,500000.0],PARAMETER[“False_Northing”,0.0],PARAMETER[“Central_Meridian”,115.0],PARAMETER[“Scale_Factor”,0.9992],PARAMETER[“Latitude_of_origin”,0.0],UNIT[“Meter”,1.0]]

Georeferencing

Where applicable, applicants must use the Alberta Township Survey (ATS) system, version 4.1 to georeference their data and submissions to optimize spatial accuracy.

Attributes

The following details must be submitted as attributes with every spatial information file, including vector information. Spatial information submitted in relation to a single application, must have consistent information provided for all features (i.e., submitted for each file).

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Company BA code	String (6)	Any	Mandatory	Must include the BA code of primary applicant
Company name	String (40)	Any	Mandatory	Must include the company name of the primary applicant
Project name	String (40)	Any	Mandatory	
Scheme type	String (40)	• MOS • INSITU • Processing plants	Mandatory	
Positional accuracy	Integer	Any	Mandatory	M (indicates plus/minus metres for the position on the ground)
Depth/height accuracy	Integer	Any	Mandatory	M (indicates plus/minus metres for the position above or below the ground)

Spatial Submission Details

Spatial information has been grouped into the following three feature types:

1) Project area
2) Development area
3) Project footprint

Applicants will submit one shapefile per feature type with multiple polygons (as applicable). The following data requirements apply to each feature.

Project Area

Description: See appendix 1 under "project area" for the definitions of in situ, mining, and processing plant project areas.

Geometry: Polygon

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Name	String (40)	Any	Mandatory	The name of the oil sands project.
Type	String (40)	• Project area • Development area	Mandatory	The type of boundary.

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Project area	String (40)	Proposed project area	Mandatory	
Deposit (geological pool or deposit name)	String (40)	Refer to deposit section in appendix 4 for valid deposit values.	Mandatory	
Submission date	Date	YYYYMMDD	Mandatory	

Development Area

Description: See appendix 1 under "development area."

Geometry: Polygon

In Situ Development Area (Drainage Patterns)

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Name	String (40)	Any	Mandatory	The name of the resource recovery location (e.g., a drainage pattern ID).
In situ project area	String (40)	Proposed project area	Mandatory	
Deposit (geological pool or deposit name)	String (40)	Refer to deposit section in appendix 4 for valid deposit values.	Mandatory	
Average water saturation	Decimal (4, 3)	Any	Mandatory	Must be measured in per cent (%).
Average porosity	Decimal (4, 3)	Any	Mandatory	Must be measured in per cent (%).
Average net bitumen pay	Decimal (4, 1)	Any	Mandatory	Must be measured in metres (m).
Developable bitumen in place	Decimal (10, 2)	Any	Mandatory	Must be measured in metres cubed (m^3).
Recovery factor	Decimal (10, 2)	Any	Mandatory	Must be measured in per cent (%).
Initial established reserves of bitumen	Decimal (10, 2)	Any	Mandatory	Must be measured in metres cubed (m^3).

Project Footprint

Description: See appendix 1 under "project footprint."

Geometry: Polygon

In Situ Project Footprint

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Name	String (40)	Any	Mandatory	Structure, facility, or project footprint name.
In situ project footprint	String (40)	Proposed project footprint	Mandatory	
Scheme project footprint type	String (40)	• Oil sands processing plant • Central processing facility • Surface pad • Pipelines • Known permanent structures • Other	Mandatory	If applying the value “Other,” please specify (e.g., Other–Camp).

MOS Project Footprint

Field name	Type (maximum field size)	Permitted values	Validation	Notes
Name	String (40)	Any	Mandatory	Structure, facility, or project footprint name
Project footprint type	String (40)	• Ultimate pit limit • Oil sands processing plant • Pipelines • Tailings area • Storage area • Compensation area • Water intake infrastructure • Landfill • Dike • Project drainage system • End pit lakes • Known permanent structures • Other	Mandatory	If applying the value “Other,” please specify (e.g., Other–Camp)

Field name	Type (maximum field size)	Permitted values	Validation	Notes

Project footprint subtype
 	
Note: Do not repeat project footprint type in parentheses.
	String (40)	• (Ultimate pit limit)
		  - Toe
		  - Crest
		• (Tailings area)
		  - Fluid
		  - DDA
		  - Sand/beach
		• (Storage area)
		  - Overburden/ interburden
		  - Reclamation material stockpiles (RMSs)
		  - Coke stockpile
		  - Sulphur stockpile
		• (Compensation areas)
		  - Lake
		  - Wetland
		• (Water intake infrastructure)
		  - Water intake area
		  - Water intake pipeline
		  - Off stream storage ponds (OSP)
		• (Project drainage area)
		  - Stream diversion
		• Other
			Mandatory	If applying the value "Other," please specify (e.g., Other–Camp)

Maximum potential volume (total capacity)	Integer (10)	Any	Mandatory for project footprint types: tailings area and storage areas	Must be measured in metres cubed (m^3) For proposed overburden, RMS, and tailings areas
Maximum proposed elevation	Integer (10)	Any	Mandatory for project footprint types: tailings area and storage areas	Must be measured in metres above sea level. For proposed overburden, RMS, and tailings areas

Processing Plant Footprint

Field name	Type (maximum field size)	Permitted values	Validation	Definition
Name	String (40)	Any	Mandatory	Structure, facility, or project footprint name
Processing plant type	String (40)	• Oil sands processing plant • Pipelines • Known permanent structures • Other	Mandatory	If applying the value "Other," please specify (e.g., Other–Camp)

Appendix 3 Modelling Submission Specifications

The AER will use modelling data to assist with the application review process. Below are the modelling submission requirements that will enable the AER to receive, store, and analyze the modelling data.

Submission Requirements

If your application meets the model submission requirements, model data/files must be submitted in the following formats:

Model type	Accepted formats
Reservoir	.dat
Geomechanical	.txt
Mining	.dm,.csv,.dxf

Model files must be zipped in a zip file.

In case the applicant is unable to provide the model data/files in the required formats, the applicant must seek approval from the AER to use alternative formats.

Mine Modelling Requirements

Directive 023 **requirement**	**Model data submission requirements**
126	The following electronic core hole data is required to be submitted in four separate.csv files, projected in NAD 83 coordinates: • Collars file including - unique well identifier (UWI), - hole name, X, Y, Z (ground elevation above sea level) coordinates, - TD (total hole depth), - Top_McM (elevation of top of McMurray formation), - Top_Dev (elevation of top of Devonian), and - RR_Date (date of rig release). • Assays file (including the hole name, UWI, from [distance from sample top to ground elevation], to [distance to sample bottom from ground elevation], bitumen [wt%], water [wt%], solids [wt%], fines [particle size of 44 microns or smaller] as a percentage of total solids [wt%], and any other analyzed contents). • Facies file (including the hole name, UWI, from, to, facies name). • Lithology file (including the hole name, UWI, from, to, and lithology name).
136	Digital spatial data is required for each of the following project features: • Project area • Ultimate pit limits and final pit shells • Storage and disposal structures • Plant sites • Tailings structures • Watercourses • Stream diversions • Compensation lakes • Sedimentation and emergency ponds

Directive 023 **requirement**	**Model data submission requirements**
	• Utility corridors • Any other known permanent facilities
140	Digital spatial data for each area or structure proposed for sterilization and/or waste.

Appendix 4 Geological Units

For the target oil sands deposit (listed in bold font under each oil sands area), applicants must provide mapping and a geological discussion for each of the stratigraphic units listed, as per section 6.1. In situations where the stratigraphic unit listed is not within the project area due to erosion or subcropping, provide a discussion and mapping for the location of the subcrop and erosion edge.

Athabasca Oil Sands Area

Wabiskaw-McMurray: Quaternary, Grand Rapids, Clearwater Valley (sand), Clearwater Shale, Wabiskaw, McMurray, Subcretaceous Unconformity, and Prairie Evaporite

Nisku: Grand Rapids, Clearwater, Wabiskaw-McMurray, Calmar, Nisku, Upper Ireton, Grosmont, and Ireton

Grosmont: Grand Rapids, Clearwater, Wabiskaw-McMurray, Nisku, Upper Ireton, Grosmont D, Grosmont CD Marl, Grosmont C, Grosmont C/B Mud, Grosmont B, Grosmont B/A Mud, Grosmont A, and Lower Ireton

Leduc: Clearwater, Wabiskaw-McMurray, Ireton, Leduc, Cooking Lake, Beaverhill Lake

Grand Rapids: Quaternary, Colorado, Viking, Joli Fou, Grand Rapids (Upper, Middle Lower), Clearwater, Wabiskaw-McMurray, Subcretacous Unconformity

Cold Lake Oil Sands Area

Clearwater: Colorado, Viking, Joli Fou, Grand Rapids, Clearwater Shale, Clearwater Sand, Wabiskaw-McMurray, Subcretacous Unconformity, and Prairie Evaporite

Grand Rapids: Colorado, Viking, Joli Fou, Upper Grand Rapids, Lower Grand Rapids, Cummings-Dina, Subcretacous Unconformity, and Prairie Evaporite

Peace River Oil Sands Area

Bluesky-Gething: Base of Fish, Paddy-Cadotte, Harmon, Notikewin, Falher, Wilrich, Bluesky, Gething, and Subcretacous Unconformity

Pekisko: Wilrich, Bluesky-Gething, Shunda, and Pekisko

Shunda: Wilrich, Bluesky-Gething, Debolt, Shunda, and Pekisko

Debolt: Wilrich, Bluesky-Gething, Triassic Strata, Debolt, and Shunda

Belloy: Wilrich, Bluesky-Gething, Triassic Strata, Belloy, and Debolt

Appendix 5 In Situ Resource Delineation Guidelines

The AER expects applicants to have obtained an adequate amount of resource delineation to support their application. This section details guidelines for the minimum amount of resource delineation necessary for the AER to conduct a review of an application.

The project area must be delineated adequately so that the applicant can demonstrate that there is potentially recoverable bitumen within each section. To achieve this, applicants are to have drilled at least one well per section in each of the sections in the project area.

Table 1 indicates by deposit/formation the minimum number of wells per section needed to properly evaluate the resource in order to finalize the pad, well, and facility locations in the development area before the application is submitted. The minimum number of wells to be cored per section is four wells or 50 per cent of the wells listed in the table, whichever is greater.

The AER will consider requests by applicants to reduce the number of delineation wells per section as indicated in table 1 if the applicant can demonstrate that there is enough information to adequately delineate the resource. For example, 3-D seismic information obtained specifically for in situ bitumen recovery may qualify the project for reduced delineation well density.

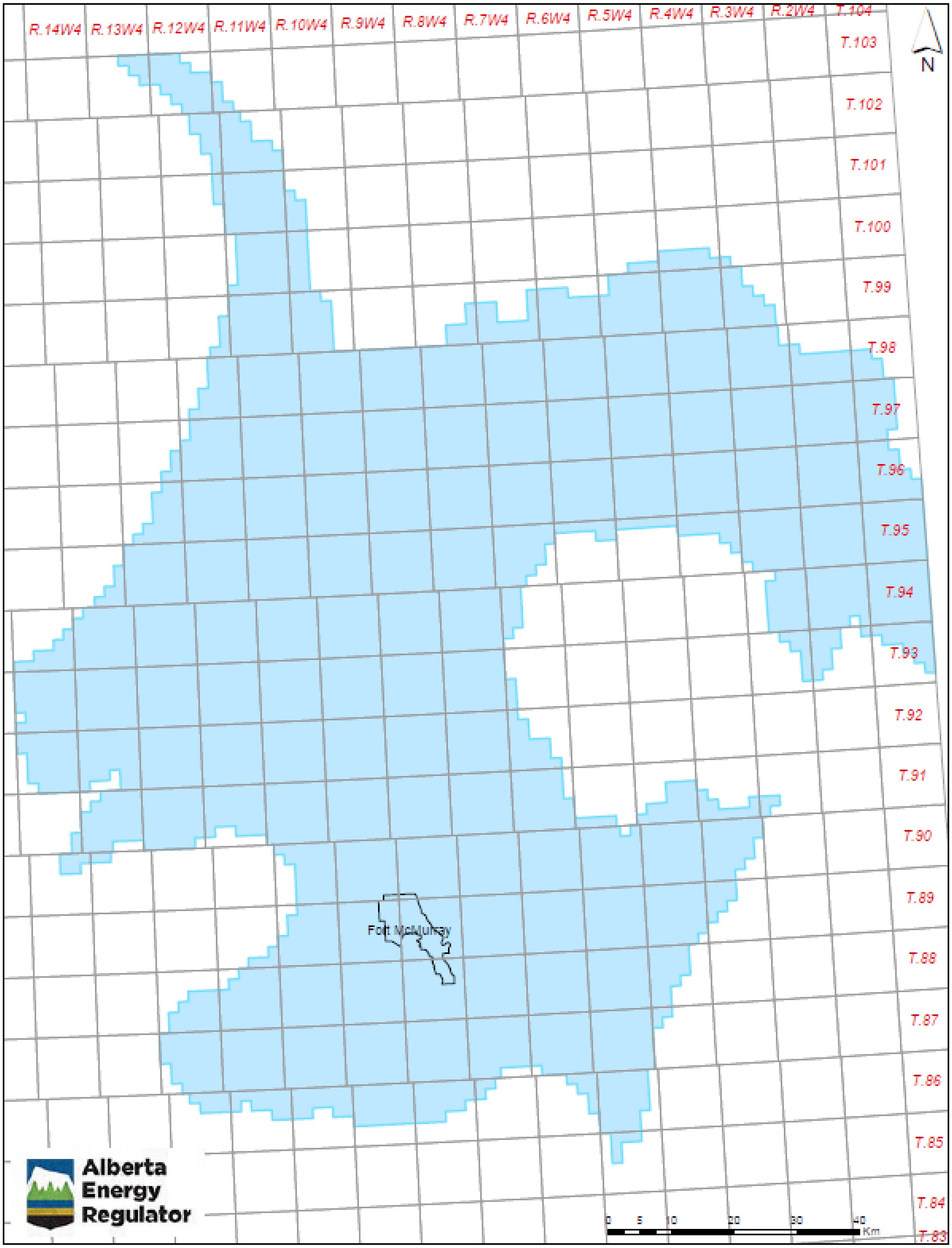
The AER will also consider requests for a lower level of resource delineation where significant environmental constraints prevent attaining the required level.

It is the applicant's responsibility to meet with the AER well in advance of filing an application if the applicant intends to vary from the AER resource delineation guidelines. This will minimize the risk of the application being considered incomplete due to inadequate information.

AER in situ delineation well guidelines

Deposit / formation	Delineation wells per section
Athabasca Grand Rapids	8
Athabasca Wabiskaw-McMurray	16
Peace River Bluesky-Gething	8
Cold Lake Grand Rapids	8
Cold Lake Clearwater	6
Cold Lake Wabiskaw-McMurray	16
Carbonate deposits (e.g., Grosmont and Leduc)	8

Appendix 6 Shallow Area



Appendix 7 Generic Energy Balance

Energy In

Stream	Units	Year		
		Input	Lower heating value (LHV)	Total energy (GJ)
Product receipts	m^3			
Gas receipts	$10^3\ m^3$			
Electricity imports	MWh			
Total energy in				

Energy Out

Stream	Units	Year		
		Input	Lower heating value (LHV)	Total energy (GJ)
Product sales	m^3			
Gas dispositions	$10^3\ m^3$			
Electricity exports	MWh			
Site use and losses				
Losses	m^3			
Fuel use	$10^3\ m^3$			
Flared or wasted	m^3			
Other	-			
Total energy out				
Energy out (product streams)				
Energy efficiency (total energy out [product stream] / total energy in)	%			
Energy intensity (per saleable products / bitumen produced / oil sands mined)				

Appendix 8 Drillhole Inventory Table—Example

Drilling date	Number of drillholes	Drillhole data quality	Facies description (yes/no)	Type of laboratory analysis	Type of logs run
1950s	35	poor to good	no	bitumen, mineral	none
1960s	0				
1970s	167	poor to good	no	bitumen, fines, some water, mineral	gamma ray, caliper, resistivity, neutron density
1980s	0				
1990–1999	0				
2000	210	excellent	yes	bitumen, mineral, water, particle-size distribution	gamma ray, caliper, resistivity, neutron density
2001	123	excellent	yes	bitumen, mineral, water, particle-size distribution	gamma ray, caliper, resistivity, neutron density

Appendix 9 Transfer of Approval

AGREEMENT TO TRANSFER APPROVAL(S) BETWEEN

[Company name] of the city of [Name of city] in the province of Alberta, referred to as the **transferor**, and [Company name] of the city of [Name of city] in the province of Alberta, referred to as the **transferee**.

The **transferor**, who is the holder of AER approval no. [####] , dated the [Calendar day] day of [Month] [Year] (or of the attached list of AER approvals) for a [Type of project] project, for good and valuable consideration, transfers to the **transferee** the approval(s) and all the **transferor's** right and title in the approval(s).

The **transferee** agrees to the transfer of the AER approval (or attached list of AER approvals), acknowledges that it is aware of the details and conditions of the approved [Type of project] project, and agrees to carry out the project as approved.

The address of the **transferee** in Alberta is [Company address].

Dated at [Name of city] , on [Month day, year].

Signature: ________________________________

Authorized representative of transferor

Signature: ________________________________

Authorized representative of transferee