Guidelines for reporting and submission of petroleum data

A guideline in relation to the Australian Government's *Petroleum (Submerged Lands) Act 1967* and *Petroleum (Submerged Lands) (Data Management) Regulations 2004* and State/Territory Legislation.

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These guidelines set out arrangements to ensure a uniform and consistent approach to administration of the *Petroleum (Submerged Lands) Act* and the *Petroleum (Submerged Lands) (Data Management) Regulations 2004*.

The Guidelines will assist industry in managing data submission requirements and for feedback. They will be modified as required in accordance with prevailing petroleum legislation and supporting regulations. Title holders are encouraged to submit data in the manner described in the document. In the event of disagreement between these guidelines and current legislation or directions, the latter will prevail.

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GENERAL

1 The purpose of the guidelines is to specify the format, contents and standards required for preparation and submission of petroleum exploration, development and production data as required by the Petroleum (Submerged Lands) (Data Management) Regulations 2004 (Data Management Regulations). The guidelines allow for data management arrangements to be flexible and modified as necessary in line with circumstance and technology changes. The Regulations are objective based and provide a framework for encouraging the adequate collection and timely dissemination of petroleum data for the long term benefit of the Australian community by assisting in ensuring the adequacy of the data acquired and to allow for the efficient management of data confidentiality and the disclosure of data on completion of relevant confidentiality periods. An important aspect of the Regulation is the development of an agreed Data Management Plan (DMP) specifying acceptable methods of acquiring, maintaining and submitting data including the possibility of approved holders storing and maintaining the data.

2 Titleholders are encouraged to submit this data as soon as possible and are required to submit the data according to the timeframes specified in the DMP. For clarity, the Australian Government and State/Territory authorities consider the timeframes indicated in the attached tables as reasonable maximum times to lodge data and information unless otherwise approved in a DMP. Petroleum data shall contain information of sufficient standard and detail to substantiate, to the satisfaction of the Designated Authority or Minister, the activities undertaken on a petroleum permit, lease, license, drilling reservation or special prospecting authority as reported to the Designated Authority.

3 Under the Australian Government *Petroleum (Submerged Lands) Act 1967* (PSLA Act) and *Petroleum (Submerged Lands) (Data Management) Regulations 2004* and under equivalent State/Territory legislation, data shall be submitted to the Designated Authority and the Australian Government for the following types of petroleum titles:

- **Exploration Permit**
- **Production License**
- **Retention Lease**
- **Special Prospecting Authority (SPA)**
- **Scientific Investigation (SI)**
- **Access Authority (AA)**

for the following geoscientific activities undertaken in the search for hydrocarbons:

(a) Drilling programs

(b) Geophysical surveys (seismic, magnetic, gravity, etc.)

(c) Reprocessing studies (seismic, magnetic, gravity, etc.).

4 Data required by the Designated Authority, as described in the attached guidelines are to be submitted as follows:

For Australian Government area titles one copy or set to:

Manager,
Geoscience Australia Data Repositories
Geoscience Australia
cnr Jerrabomberra Ave and Hindmarsh Drive
SYMONSTON ACT 2609

and one copy or set to:

the Relevant Designated Authority.

5 For both State and Australian Government area titles held under the PSLA Act, data other than seismic field tapes (such as well log data, processed seismic, aeromagnetic, and navigation data) shall be sent accompanied with a completed *Transfer Proposal* form (attached) to the relevant Designated Authority.

6 For seismic field data, send only the completed *Transfer Proposal* form to the relevant Designated Authority. Once approved, the company will be informed where and when the digital field data is to be sent.

7 Formats for data to be submitted are specified in Tables 1–5 and 7.

8 Operators of permits who would otherwise be required to submit seismic field data under the PSLA Act may apply to the Designated Authority to retain that data in their facilities or to store it in third party facilities subject to the specific approval of the Designated Authority. The conditions that must be met prior to the granting of any such approval are given below. Any such approval is at the discretion of the Designated Authority and must be obtained separately for each survey.

CONFIDENTIALITY OF DATA

9 All information and data submitted to the Designated Authority and the Australian Government in accordance with the Petroleum (Submerged Lands) Act and the Petroleum (Submerged Lands) (Data Management) Regulations shall remain confidential at least until the information is eligible for public release, as prescribed in Section 150 of the Australian Government Petroleum (Submerged Lands) Act 1967 and the Petroleum (Submerged Lands) (Data Management) Regulations 2004.
For data submitted prior to 7 March 2000, the date on which data and information may become eligible for release is determined by the provisions of Section 118 of the Petroleum (Submerged Lands) Act 1967 as in force at that time. Since then the determination of the date on which data and information may become eligible for release fall under the provisions of Section 150(E) of the PSLA and Part 6 of the Data Management Regulations which describe the "relevant day" on which submitted data can be publicly released. The relevant day is typically expressed as the number of years from when the data was submitted, or deemed (Section 150 (b)) to have been submitted.

ACCEPTABLE MEDIA

10 For data submitted under the requirements of the PSLA Act, the preferred medium for all data where possible, except seismic field data and large data sets, is CD-ROM and/or DVD.

Submission of data other than seismic field data on other media, including 9 track tape or 8 mm format, must have prior approval of the Designated Authority.

The preferred medium for seismic field data and large data sets is 3590 cartridge. Seismic data will be accepted on other media if that other medium is the original recording medium and the data has not been re-mastered, or if the data has been re-mastered, with the prior approval of the Designated Authority in consultation with Geoscience Australia. Evidence will be required that the re-mastering has been completed to meet Geoscience Australia's re-mastering standards.

PDF to be submitted as security free.

No stick on labels to be used on DVD medium.

ARCHIVE PRACTICE FOR DIGITAL DATA

11 Where operators request to retain their seismic field and processed data beyond the required submission date, then these data must be managed using good digital archiving principles. These include:

- Monitoring the condition of the media upon which the data is stored to ensure data integrity is maintained during the storage period;
- Transcribing to new high density media before the old media deteriorate;
- Ensuring open file data is released upon request in a timely fashion and in such a manner as the preservation and security of the data is not compromised;
- Records of original data usage are kept and the Designated Authority advised on an annual basis of the status of the data.

Original data cannot be exported overseas without the written consent of the Designated Authority.

National Archives of Australia recommend the following standards for storage of magnetic media:

Environment

Temperature/RH	**Air quality**	**Lighting**
• Maximum stability required • 18-20°C ± 2°C • 45-50%RH ± 5% RH = relative humidity	• filtered to exclude dust and other particles • filtered to exclude acidic & oxidizing gases • well ventilated	• UV-filtered fluorescent lighting • Timer controlled switches

Safety and protection

Fire	**Security**	**Housing**	**Containers**
• VESDA (very early smoke detection apparatus) • Fire alarms • Carbon dioxide	• 24-hour physical or electronic surveillance • alarm systems • controlled access	• Non-magnetic shelving • Tape reels must be suspended	Non-magnetic, archival quality sealed containers, cassettes, cases or sleeves

extinguishers • Total gas flooding system		vertically on the hub	

REPORTING AND DATA SUBMISSION REQUIREMENTS

DAILY REPORTS - On commencement and on each day before midday a daily report of the Drilling Operations for the previous 24 hours shall be sent to the Designated Authority.

12 Daily Reports shall contain where available:

12.1 The name, location elevation/water depth of the well;

12.2 The drilled depth:

12.3 The work carried out:

12.4 The lithology of formations penetrated;

12.5 Any indications of petroleum;

12.6 Results of surveys made in the well bore, and

12.7 Estimated daily and cumulative well costs.

12.8 Summary of material usage.

12.9 Leak off test summary.

13 WEEKLY REPORTS – If a geological or geophysical survey is in progress, a report must be given about survey operations carried out during a week. The weekly report must be given as soon as practicable after the end of the week to which the report relates.

14 MONTHLY REPORTS - A monthly report normally on a field by field basis, relating to the last preceding calendar month shall be submitted no later than the 15th day of each month.

Monthly Production Reports shall contain a record of the total quantities of:

14.1.1 Liquid and gaseous petroleum and water produced.

14.1.2 Liquid and gaseous petroleum used.

14.1.3 Gaseous petroleum flared or vented.

14.1.4 Liquid and gaseous petroleum and water injected.

14.1.5 Liquid petroleum stored.

14.1.6 Liquid and gaseous petroleum delivered from the area, and

14.1.7 an estimate of average reservoir pressure per reservoir and the cumulative quantities of liquid and gaseous petroleum and water produced or injected as at the end of the month; and equivalent data for the last production test;

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and, for each well:

14.1.8 Its identification name and number.

14.1.9 A summary of all work performed on each well in the licence area during the previous month.

14.1.10 The result of the production test including choke sizes used, flowing tubing head pressure and separator pressure observed during the test

14.1.11 Shut in well head pressure if the well were shut for any reason during the month.

14.1.12 Its status at the end of the month.

14.1.13 The number of days of production, and

14.1.14 The total estimated quantities of liquid and gaseous petroleum and water produced or injected during the month and the cumulative quantities of liquid and gaseous petroleum and water produced or injected as at the end of the month; and equivalent data for the last production test;

14.2 Wireline Survey Reports shall include a record of the information gathered during the survey, together with any records (including data collected) made for the purpose of the survey (Wireline operators report).

14.3 Subsurface Safety Valve Operation Reports, shall include:

14.3.1 The name of the platform

14.3.2 The well number

14.3.3 The date

14.3.4 The time taken

14.3.5 A description of the work performed

14.3.6 The condition of equipment removed

14.3.7 Any other matter the Designated Authority may require

15 QUARTERLY REPORTS - Two copies of each quarterly report shall be submitted to the Designated Authority

15.1 Exploration Permit Reports shall contain:

15.1.1 A brief review of operations (including office studies) carried out with particular reference to fulfilling the work commitment for the permit year

15.1.2 Estimated expenditure for the quarter

15.1.3 Survey statistics

15.1.4 Relevant geophysical and geological interpretations

15.1.5 Such other relevant information as the Designated Authority, requires

15.2 Summary of Records of Discharge of Produced Formation Water (see clause 655 of directions) shall include:

15.2.1 The results of tests of equipment which monitors and records the concentration of petroleum in discharged formation water

15.2.2 The rate of discharge of formation water

16 ANNUAL REPORTS

16.1 Annual Reports – Are to include a more comprehensive report than the quarterly report, including the following:

16.1.1 A general discussion of permit status and operations carried out (including office studies) with particular reference to fulfilling the work commitment for the permit year

16.1.2 Technical conclusions derived from the year's operations

16.1.3 A list of reports submitted during the year

16.1.4 An outline of work plans for the next year with particular reference to fulfilling the work commitment for the permit year

16.1.5 Current and appropriately scaled interpretation maps

16.1.6 A summary of annual expenditure

16.2 Annual Reports on Production Licenses - Two copies of each annual report relating to the last preceding year shall be submitted to the Designated Authority no later than the month of September.

17 TITLE ASSESSMENT REPORTS (TAR)* (a generic term that refers to information and data required under the PSLA Act Schedule – *Specific Requirements as to Offshore Petroleum Exploration and Production* (Directions) and is covered by Sections 550,650,651 and 652) shall contain the following**:**

A notification of discovery (see 20 below) should be submitted within 3 days after discovery, and the first Title Assessment Report, incorporating the initial assessment of petroleum in place, should be submitted within three months of any discovery. Subsequent TARs are issued thereafter in September of each year. A specific contact in the operator's organisation report should be given for enquiries relating to the report. The title assessment report should be divided into sections covering each field within the title area. It replaces the need for a Programme of Work contained in the current Directions. Any changes in title equity over the reporting period should be noted.

For each field in a permit, lease or production licence:

17.1 Following Discovery

- Discovery Report - For new discoveries, a brief description of the discovery well results, including compositions, reservoir thickness, pool(s) intersected,

flowrates, volumes recovered, pressures, interpreted formation properties, log results and preliminary hydrocarbons in place and reserves estimates should be given. Further appraisal plans should be outlined.

- Summary of Recent Activity - For previous discoveries, a brief review of the exploration and/or production operations, and production performance, with divergence from the expected performance in the FDP (if any) noted and discussed in more detail in later sections.

17.2 Field Description

- Hydrocarbons initially in place and reserves - Changes in estimates of hydrocarbons initially in place and reserves should be identified by reference to the Field Development Plan (FDP) base case and/or to the case in the previous TAR, and accompanied by the data and reports on which they are based . Reserves should be reported in the following categories, where compositional data is available:

  - gas (methane plus ethane);

  - LPG (propane plus butane);

  - condensate (C5+); and

  - crude oil.

  For non- commercial fields, technically recoverable volumes should be reported.

- Well Status and Operations - A table summarising changes in well status (e.g. producer/injector, suspended/abandoned, perforated intervals, reservoir identifier, lift provision) should be included and should note any well operations carried out during the reporting period (e.g. drilling, workover, data gathering, perforating, stimulation).

- Geology - Where drilling, seismic re-processing or other work has had a significant impact on the reservoir model a summary of the results should be provided, together with a map in subsea depth giving the current interpretation of the top structure and showing well locations and fluid contacts (by reservoir if appropriate).

17.3. Reservoir Management

- Field Management - Changes in development strategy should be reviewed. Important reservoir monitoring results, reservoir monitoring limitations and specific production difficulties should be summarised. Plots of

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reservoir pressure and voidage replacement should be provided. Plans for reservoir monitoring in the coming year should be discussed.

- Studies - Results and relevance of geoscience or reservoir engineering studies completed during the reporting period should be summarised. Plans and timescale for ongoing and future studies should be discussed.

- Improved Oil Recovery (IOR) - Where improved recovery has not been addressed in the FDP or in previous reports, the potential should be reviewed, and the results of any studies or operations discussed.

- Forecasting - A comparison between the current forecast and the FDP production and injection profiles (or those agreed revisions made in earlier TARs) should be provided and the current estimate of the Cessation-of-Production date should be provided.

- Proposed changes to the FDP- Proposed changes to commitments or to conditions in the field development plan should be set out clearly as should plans to extend the development. The need to include other deviations should be discussed with the Designated Authority.

  A summary of longer term development opportunities within or around the field, including where appropriate potential for recovering third party hydrocarbons, should be provided. Progress in developing opportunities already identified should also be reviewed.

  Where changes in the facilities and infrastructure are planned the proposed modifications should be summarised, together with estimates of (Operating Expenditure) OPEX and (Capital Expenditure) CAPEX. Where an incremental project is planned the corresponding incremental production should be identified.

  Where facility modifications on a host platform are planned for a satellite development, the proposed changes should be addressed in a TAR for the host field and only a cross reference provided in the TAR for the satellite field

- Field Operating Costs –CAPEX and OPEX profiles should be provided for the previous year, together with a three year projection of predicted expenditure; categorised as follows where applicable:

  - New wells;

  - Workovers, side-tracks etc;

  - Facilities routine maintenance;

  - Facilities upgrades/de-bottlenecks;

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-Major facilities modifications for third-parties etc; and.

-Any large variations from the previous TAR should be explained.

- Preparation for Cessation-of-Production (COP) - This should be included commencing from about five years prior to the operator's anticipated date for COP. The contents of this section shall be similar to the information required for the stand-alone COP document as defined in Appendix 7.

  The current estimate of COP date should be provided, together with a discussion of any factors that would advance or postpone the economic limit.

  Where a regular review of remaining outstanding development opportunities has been provided within the TAR it can be expected that only minimal documentation required for the COP document.

*Data in Section 17 are that often used by government as background in assessing applications for declaration of locations, retention leases, production licenses or for major changes to production licenses; submission is thus likely to speed those processes.

OTHER REPORTS:

Two copies of following reports shall be supplied to the Designated Authority as specified. In addition, the Designated Authority may, from time to time, request in writing that the title holder provide copies of specific reports.

18. WELL COMPLETION REPORTS shall be submitted to the Designated Authority and shall contain:

18.1. The name of the well

18.2. Elevation of the ground level and kelly bushing (KB) or rotary table (RT) (onshore), or water depth (WD) and kelly bushing or rotary table (offshore)

18.3. Well location in geographical coordinates, shotpoint number and seismic line annotations where appropriate, and including the permit name, graticular block number, and map sheet.

18.4. If the well is deviated or horizontal:

18.4.1. the surveyed path of the well,

18.4.2. coordinates of the bottom hole location, and

18.4.3. in the case of a potential producer, the coordinates at the intersection of the reservoir horizon

18.5. The drilling rig and drilling contractor used

18.6. Wireline logging and mudlogging contractors used

18.7. The spud date, date at which TD is reached, date of plug and abandonment (dry hole), and date of rig release

18.8. The measured depth of the hole end, where appropriate, the true vertical depth (TVD) below the KB or RT

18.9. A statement whether the well has been:

18.9.1. completed as a producer,

18.9.2. suspended as a potential producer, or

18.9.3. abandoned

Drilling

18.10. The depth of perforations in the petroleum reservoir (if any)

18.11. Particulars of the equipment installed in or on the well

18.12. Particulars of the casing and equipment installed in or on the well complete with schematics showing major dimensions

18.13. Particulars of all deviation surveys made in the well

18.14. Information on all cementing operations and schematics of abandonment

18.15. Bit records

18.16. Drilling fluids (muds) used in the well

18.17. Sample depths and types of all cores (including sidewall cores (SWC)), cuttings, and sample intervals

18.18. Well evaluation logs (including measurement while drilling (MWD) logs, pressure detection logs, and mud logs), and fluid samples.

18.19. Particulars of any hydrocarbon indications

18.20. Particulars of the operation and results, including raw pressure-time listings for all formation fluid sample tests and production tests (if any)

18.21. The measured depth and TVD of marker horizons (formation tops)

18.22. Particulars of the geological interpretations of the observations made as a result of drilling the well, including:

18.22.1. lithology and stratigraphy,

18.22.2. reservoir quality,

18.22.3. source rock quality, and

18.22.4. trap integrity: for development wells — details of changes to the current reservoir model

18.23. For exploration wells — a discussion of the relevance of the findings of the well to the evaluation of the hydrocarbon potential of the area; and for development wells — the implication for future field management

Appendices

18.24. Reports of technical studies on velocity surveys, logs, samples, cores, and side wall cores obtained from the well (including petrophysics, palaeontology, reservoir characteristics, fluid estimations, relative permeability, capillary pressure, fluid, and geochemical analyses)

18.25. One copy of:

18.25.1. a composite well log,

18.25.2. enclosures in the velocity survey report,

18.25.3. a mud log, and

18.25.4. if prepared — a wellsite geologist's lithology log

18.26. A well index sheet

18.27. Copies of revised structure maps and appropriate interpreted seismic sections illustrating post drilling structural and stratigraphic interpretation of the well

19 FINAL SURVEY REPORTS shall be submitted to the Designated Authority within the timeframe shown in the relevant tables.:

Acquisition Reports

19.1.1 Name and location of the survey including the titles in which it was conducted

19.1.2 Dates of the start and finish of the survey

19.1.3 Names of the contractors used to carry out the survey

19.1.4 Details of all equipment used

19.1.5 Geometry of acquisition parameters

19.1.6 Line lists (the listings should be of individual tapes with the corresponding shot point ranges)

19.1.7 System and equipment used for positioning and / or navigation

Processing Reports

19.2.1 Name and location of the survey including the titles in which it was conducted

19.2.2 Dates of the start and finish of processing

19.2.3 Name of the processing company

19.2.4 Objectives of the processing

19.2.5 All processing sequences and techniques used, required to reproduce the final product

19.2.6 Sample EBCDIC header dump from the final dataset.

19.2.7 Comprehensive listings of all processed data (the listings are to contain data description, line and shot point ranges)

19.2.8 Polygon position description – for 3D only

19.2.9 Calculation for 3D line numbering convention (inline and crossline)

Interpretation Reports

Interpretations, including maps, made as a result of the survey (unless the survey was a non-exclusive SPA)

20 Notification of Discovery Reports shall be submitted to the Designated Authority within 3 days of the discovery and shall contain particulars of:

20.1 The chemical composition and physical properties of the petroleum

20.2 The nature of the subsoil in which the petroleum occurs

20.3 Any other matters relating to the discovery that are specified by the Designated Authority

FIELD DEVELOPMENT PLANS*

21 Field development plans (FDP) (refer to PSLA Section 41 (1) (b) and (c))shall precede or accompany the following events:

- an application for a Production License, or
- an application for consent to make a major change to an accepted FDP including development of new fields within an existing production licence, or
- identification of a new or increased risk to the resource, or
- before a period of 5 years after acceptance of the FDP has elapsed;
- application for consent to cease production,

The FDP shall contain particulars of:

21.1 **Summary of proposed development** - This should briefly describe the essential features of the proposed development plan including:

- a description of hydrocarbon reservoirs and their proposed development including wells, pipelines and other transport facilities;
- structure maps, including fluid contacts and existing and proposed wells;
- maps indicating the proposed development in relation to the permit, field boundaries and any existing developments;
- a project schedule;
- a statement of intent in regard to any parts of the field not addressed by the field development plan including any commitment to later development of that area, or to the later stages of a phased development. Any provision for the development of other hydrocarbons in the area should also be identified;
- essential elements of the planned management of the field, including safety considerations, and;
- brief statement on ultimate abandonment.

21.2 **Production overview** which should include:

- estimated annual production rates;
- gas (methane plus ethane) content of produced fluids;
- LPG (propane plus butane) content of produced fluids;
- condensate (C5+);
- crude oil;
- formation water; and
- flared gas and gas usage.

It would be useful if these rates could be broken down into contributions from each well and production layer or zone. A statement of the extent to which these profiles are dependent on assumptions in relation to well capacity, sequence of drilling etc. would also be useful. If profiles are subject to considerable uncertainty the range of such uncertainty should be given.

Gas production should give estimated specific gravities and be provided at standard conditions (15 degrees C, 101.325 kPa).

The plateau hydrocarbon production rate (if appropriate) should be nominated, with supporting reasons for the level proposed. Particular attention should be paid to terminal rates of hydrocarbon and water production and demonstrating means of achieving separation of oil and water towards the end of field economic life.

Description, and rates, of any hydrocarbon or other gases proposed to be flared or vented.

21.3 **Geology and reservoir information** including:

- History of discovery and appraisal; and

- Reservoir data.

The purpose of this section is to present the description of the field on which the development has been based and provide a baseline for future modifications as development proceeds.

The geological data provided should reflect the basis of reservoir subdivision, and correlations within the reservoir, and include the relevant reservoir maps on which the development is based.

- Geology and geophysics
- A brief summary of the extent and quality of the seismic survey and the structural configuration of the field should be presented using appropriate figures and maps:
  - .. stratigraphy, facies variation, geological correlations within reservoir, vertical and horizontal continuity;
  - .. structure; and
  - .. depositional model of the field
- formation parameters, such as from:
  - .. log interpretation;
  - .. core analysis; and
  - .. well tests
- fluid contacts
- reservoir fluid parameters, such as from:
  - .. PVT analysis
  - .. reservoir fluid chemical analysis
- regional and local aquifier properties and observed or expected performance

21.4 **Hydrocarbons-in-place -** Estimate of oil and gas in-place for each reservoir zone. The variability of estimates should be discussed, and the basis of these estimates should be available and referenced.

21.5 **Reserves**

Reserve estimates for each reservoir should be provided, with technical support from reservoir simulation**.** Results should be given for primary recovery and, where relevant, alternative schemes of secondary recovery and enhanced recovery. The effect of the different development options on the reserves should be quantified and discussed. In the case of gas reservoirs containing condensate, the choice of depletion route should be discussed.

The range of reserves estimates provided should also be accompanied by the probability of the estimates where operators adopt probabilistic methodology. The assumed economic cut-off should be stated.

Details should be given on any pressure maintenance plans including the rates of injection over the field life and level of reservoir pressures to be maintained.

Discussion of the degree of heterogeneity in the reservoir should be included especially if it is likely to affect sweep efficiency or the maximum rate at which the reservoir can be produced.

Geological and other evidence for any level of aquifer support assumed should be provided.

21.6 Reservoir development and management

A plan with indicative timings for the measurements proposed to monitor geological, petrophysical and reservoir aspects in any development wells should be included and the intended coring philosophy should be stated. The proponent should describe how it is proposed to establish and monitor depletion of the reservoir, which should include downhole pressure surveys and other measurements (such as production logging and thermal neutron decay time logging or other cased hole logs to indicate hydrocarbon contact positions).

Where the reservoir has been subdivided for reservoir analysis into flow units and compartments the basis for division should be stated. A description of the extent and strength of any aquifer(s), and effects on other fields in contact with the same aquifer(s), should be given.

The means of representing the field, either by an analytical method, some form(s) of numerical simulation, or by a combination of these should be briefly described.

The rationale behind the data gathering and analysis proposed in order to resolve the existing uncertainties and understand dynamic performance of the field during both the development drilling and production phases should be outlined. Where the use of unmanned or subsea facilities may set restrictions on data gathering, these should be identified. The chosen recovery process should be described and the optimisation method summarised, including reference to the potential for artificial lift and stimulation. Any limitations on recovery imposed by production technology or by the choice of production facility or location should be indicated.

Proposals involving production below the bubble point of oil reservoirs, or below the dew point of gas reservoirs, should be carefully described and justified, including effects on reserves and proposed monitoring and control mechanisms.

Remaining uncertainties in the physical description of the field which may have material impact on the recovery process should be described and a program to resolve these should be provided.

21.7 Development drilling

The proposed drilling pattern and program for new production and injection wells, workovers, re-completions, and re-perforations should be described, indicating the degree of flexibility and contingency built into the overall plan that will allow the program to be altered in order to maximise on a commercial basis estimated hydrocarbon recovery taking into account improved knowledge of the reservoir properties and performance as the field is developed. Expected reservoir sweep should be indicated.

The program for completion intervals should be described and discussed. Some indication of the completion and perforation philosophy, especially in a layered

sequence where separate layers may be treated as discrete reservoir units, together with the initial years drilling/completion sequence, should be given.

Where options remain for improvement to the development or for further phases of appraisal or development, the criteria and timetable for implementing these should be given

21.8 **Well performance and well testing**

Information concerning normal and special core analysis work (not elsewhere mentioned), plus information on Drill Stem Tests (DST) and production testing should be provided. To demonstrate the capacity of the development wells to produce the reserves, well performance data should include available information on vertical lift characteristics of produced fluids with particular emphasis on estimating the water cut at which wells cease to flow at different levels of reservoir pressure.

21.9 **Artificial lift**

Any techniques considered for increasing or maintaining well productivity such as gas lift or downhole pumps should be described.

21.10 **Assisted recovery**

Any techniques considered for pressure maintenance and/or assisted recovery including water, gas or other fluid injection should be described.

21.11 **Improved oil recovery**

Potential, or techniques considered, for improved oil recovery should be discussed. Where firm conclusions cannot be reached a programme for addressing these issues during production should be given.

21.12 **Injection forecasts**

Injection rate forecasts should be provided for any injection fluids.

The potential for scaling, waxing, corrosion, sand production or other production problems and any provision made for these problems;

21.13 **Drilling, production and process facilities**

Description of the drilling facilities, should be provided and include:

- type of drilling mud;
- method for the cleaning and disposal of cuttings;
- proposed well completions; and
- well workover facilities.

A description provided of major equipment, infrastructure items and identification of the design and operating parameters used as the basis of the design. The design flexibility to cater for upside potential including incremental and satellite field development should be described where appropriate. A brief description of the operating envelope and limitations of the process plant should be provided. The use and disposal of separator gas should be described. The studies forming the basis for the selection of the proposed development option should be referenced. The section should also include:

- a brief summary of the method of metering hydrocarbons produced and utilised;

- a description of systems for collecting and treating oil, water and other discharges; and
- a brief description of any fluid treatment and injection facilities.

A description provided of the structures for the development, whether fixed, floating or subsea. A description should be provided of the proposed hydrocarbon transportation system, including, where appropriate, any onshore terminal facilities. Any limitations on offshore production resulting from constraints in the proposed structures, transportation and terminal facilities should be identified.

21.14 **Other development options considered:**

- A description should be given of each feasible option considered, and the reasons for the preferred option should be clearly indicated. Where appropriate, reference to relevant studies and evaluation reports previously submitted should be made. Particular attention should be paid to the effects on ultimate recovery of the alternative development options considered.
- A fully detailed description of the process plant is not required but the description should allow an understanding of the system, its operating envelope and any limitations. Process flow diagrams should be available for each major system, and a simplified mass balance for all of the oil, gas and gas liquids produced, utilised or transported for sale should be provided. The use and disposal of separator gas should be described. In addition, the description should include:
  - a brief summary of the methods of metering hydrocarbons produced and utilised
  - a description of systems for collecting and treating oil, water and other discharges, and
  - a brief description of any fluid treatment and injection facilities.

Some developments will include common user facilities and may have capacity constraints; the methods to be used to set production priorities should be given. For gas reservoirs the criteria for installation of additional compression should be identified.

Plans for gas gathering, recompressing and re-injection should be provided. If gas is proposed to be flared, the reason for this should be given.

21.15 **Project planning and management**

- Schedules defining key events and decision dates in the design, procurement, construction and commissioning stages of the major elements of the development should be provided. A critical path schedule should show the critical events and an indication should be given of the effects of uncertainties outside the immediate control of the project on project timing, eg weather, delivery of key items of equipment.

- The schedule should show the likely timing for statutory and other approvals required for the appropriate stages of the development.

21.16 **Costs**

Proponents may consider it desirable to provide financial data.

21.17 **Field life**

The estimated life of the field should be given showing the range of uncertainties and assumptions behind the forecast of cessation of production.

*Data in Section 21 are that often used by government as background in assessing production license applications; submission is thus likely to speed that process.

TABLE 1: WELL DATA

DATA REQUIRED	REPORT TYPE*	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT.	DATE FOR SUBMISSION (prior to or by)	REMARKS
Field and processed digital data						
Edited field data and processed data for all wireline logs, MWD or LWD tools. Includes well test raw data.	Documentary	LIS, DLIS, LAS	One copy	Data to be forwarded to GA by Designated Authority	6 months after completion of the well	With verification listing of the data supplied. The data shall include full header information.
Edited field and processed data for borehole deviation surveys.	Documentary	LIS, DLIS, ASCII, LAS, XLS	One copy	Data to be forwarded to GA by Designated Authority	6 months after completion of the well	The data shall include full header information.
Interpretative log analysis	Derivative	LIS, DLIS, ASCII, LAS, XLS	One copy	One copy	12 months after completion of the well	The data shall include full header information.
Mud logging data	Documentary	ASCII, LAS	One copy	Data to be forwarded to GA by Designated Authority	6 months after completion of the well	With a header giving field names, curve names and units of measure
Velocity surveys -raw -processed -checkshot and time/depth analysis	Documentary	DLIS, SEGY ASCII (Checkshot data)	One copy	Data to be forwarded to GA by Designated Authority	6 months after completion of the well	To include verification header file.
Core, side wall core natural light photography – UV light to be done in fluorescent sections	Documentary	JPEG, PNG or TIF	One copy	One copy	6 months after completion of the well	Provide minimum 300 DPI image in 24-bit colour. High-resolution images able to be magnified (zoom in) without pixilation.

Samples						
Ditch cuttings	Petroleum Mineral Sample		One set	One set	6 months after completion of the well	A minimum of 200g dry weight per sample interval set and thoroughly cleaned, dried and suitably packaged with indelible printing of well name, depth ranges.
Offshore - Full hole conventional cores (if cut)	Petroleum Mineral Sample		2/3 slab (after a year or as agreed)	1/3 slab (6 months after completion of the well)		Fresh core slabbed vertically of which 1/3 to be submitted to GA and 2/3 submitted to Designated Authority.
Onshore - Full hole conventional cores (if cut)	Petroleum Mineral Sample		All to be submitted (after a year or as agreed)			Core to be slabbed as per DA Guidelines.
Gaseous hydrocarbon samples (in an API approved safety container)	Petroleum Mineral Sample		GA to advise DA of receipt	To be submitted to GA	On completion of test	If collected from wireline, drill stem or production tests. Consultation with GA recommended. (300 cc if available)
Fluid hydrocarbon samples (in an API approved safety container)	Petroleum Mineral Sample		GA to advise DA of receipt	To be submitted to GA	6 months after completion of the well or after collection of sample	If collected from wireline, drill stem or production tests. Consultation with GA recommended. (1ltr if available)
Sidewall core material (if recovered)	Petroleum Mineral Sample		One set	No	12 months after completion of the well	
Palynological slides and residues Palaeontological material Petrological slides	Petroleum Mineral Sample		One set	No	12 months after completion of the well	If prepared.

Reports and images (Digital format preferred for all lodgements)						
Well Completion Report separated into: Documentary data Derivative data		 PDF PDF	 One copy One copy	 One copy One copy	 6 months after completion of the well 12 months after completion of the well	Security free basic and interpretive volumes must be separated, image files and logs included in reports must be submitted as separate JPEG or TIF files Interpretive volume to include composite well log.
Log displays.	Documentary	PDS/ META/ PDF	One copy	Data to be forwarded to GA by Designated Authority	6 months after completion of the well	Software to be provided. Continuous page at a readable scale.
Mudlog	Documentary	TIF/ PDF	One copy	One copy	6 months after completion of the well	Continuous page at a readable scale.
Well index sheet	Derivative	PDF	One copy	One copy	12 months after completion of the well	Example to be provided.
Petrophysical, geochemical or other sample analyses	Documentary	ASCII/ XLS	One copy	One copy	12 months after completion of the well	As a tab delimited ASCII file with metadata included.
Composite well log	Derivative	TIF/JPEG	One copy	One copy	12 months after completion of the well	
Velocity log displays	Documentary	TIF/JPEG	One copy	One copy	6 months after completion of the well	

Special Study Submission Requirements

Workover/re-entry report	Documentary	PDF	One copy	One copy	6 months after completion of the well	Documentary and derivative volumes must be separated; image files included in reports must also be submitted as separate JPEG or TIF files.
Reports on investigation, analysis, etc. of cuttings or cores, and reports on any overseas investigation of cuttings or core plugs	Documentary / Derivative	PDF	One copy	One copy	12 months after sampling or borrowing material	An annual report is required for any cuttings or cores retained overseas for more than 12 months
Data from investigation, analysis, etc. of cuttings or cores	Documentary	ASCII/ XLS	One copy	One copy	12 months after sampling or borrowing material	As a tab delimited ASCII file with metadata included and attached to the analysis report.

- **REPORT TYPE column refers to the type of information required. Previous to the 2000 amendment of the Petroleum (Submerged Land Act) 1967, Section 118 and the Guidelines supporting the Schedule of the Specific Requirements under the P(SL)A, reference was made in respect of Basic and Non-Basic (Interpretive) data types. Following the amendment of the P(SL)A 1967 in 2000 the previous Section 118 of the P(SL)A 1967 was re-defined in Section 150 and the data types defined as *Documentary and Petroleum Mining Sample* (previously referred to as BASIC) and *Derivative* (previously referred to as NON-BASIC or INTERPRETIVE).**
- **TP: Transfer proposals to be sent to the Designated Authority for approval to submit. The DA will then instruct as to which address the data is to be sent.**
- **NOTE: South Australian Government also requires Hard Copies for all Wire Line logs and Reports.**
- **NOTE : In addition to the above Victoria will accept PDF or CGM files for log displays**
- **NOTE : For submission of Palynology slides for Victoria – see Appendix 1**

TABLE 2: 2D SEISMIC DATA

DATA REQUIRED	REPORT TYPE	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Field Data						
Navigation data Includes final processed navigation, elevation and bathymetry data	Documentary	UKOOA	One copy	One Copy	12 months after completion of the acquisition	P1/90 or subsequent format with header information of navigation / shotpoint location data including elevations or bathymetry.. Header data must include geodetic datum, spheroid, projection and clearly stated transformation parameters. See Appendix 2.1 for example.
Raw Navigation data	Documentary	UKOOA	Transfer Proposal (TP) to be forwarded by DA	To be forwarded to GA after approval of TP by State	12 months after completion of the acquisition	P2/94 or subsequent format
Seismic field data	Documentary	SEG Standard	Transfer Proposal (TP) to be forwarded by DA	To be forwarded to GA after approval of TP by State	12 months after completion of the acquisition	
Seismic support data	Documentary	PDF	Transfer Proposal (TP) to be obtained from State DA	To be forwarded to GA after approval of TP by State	12 months after completion of the acquisition	Observers logs, For onshore data only: surveyors notes, chaining diagrams, intersections
Uphole data (onshore)	Documentary	ASCII	One copy	No	12 months after completion of the acquisition	Includes line number, shotpoint and time depth pairs for each uphole.
Itemised field tape listing	Documentary	Digital (ASCII)	One copy	One Copy	12 months after the completion of the acquisition	Field data showing tape number, survey name, line number, shotpoint range.

Processed Data						
Raw and final stacked data, near/mid/far sub-stacks - if generated	Documentary	SEG-Y	One copy	One copy	12 months after completion of acquisition	Includes fully annotated EBCDIC header.
Raw and final migrated data including PSDM / PSTM, near/mid/far sub-stacks - if generated	Documentary	SEG-Y	One copy	One copy	12 months after completion of acquisition	Includes fully annotated EBCDIC header.
Fully annotated image of final processed migrated data. (Onshore)	Documentary	TIFF	One copy	Not required	12 months after completion of acquisition	The image must have a vertical scale of not less than 5cm/sec. See Appendix 2.2 for details of requirements for relevant States.
Shotpoint to CDP relationship	Documentary	ASCII	One copy	One copy	12 months after completion of acquisition	Sufficient SP/CDP data for workstation interpretation. At least SOL and EOL relationships for each line and a listing of equivalent CDP/SP pairs for each line.
Itemised process tape listing	Documentary	ASCII	One copy	One copy	12 months after completion of acquisition	Showing tape number, survey name, line number, shotpoint range, data type.
Velocity data	Documentary	ASCII (Western format)	One copy	One copy	12 months after completion of acquisition	Including line number, shotpoint, time versus RMS pairs for both stacked and migrated velocities.
Final Reports						
Final report (operations and navigation)	Documentary	PDF	One copy	One copy	12 months after completion of acquisition	Location map included. Onboard processing and any retained outputs to be documented in report. Refer to Section 19.1
Final processing report	Documentary	PDF	One copy	One copy	12 months after completion of acquisition	Refer to Section 19.2 To include sample print out of SEGY EBCDIC header.
Final interpretation report	Derivative	PDF	One copy	One copy	18 months after completion of acquisition	Refer to Section 19.3
Digital images of interpretation maps	Derivative	TIF	One copy	One copy	18 months after completion of acquisition	These include TWT structure maps at key horizons and representative sections showing seismic horizon picks as Geo-referenced TIF images.

- **TP: Transfer proposals to be sent to the Designated Authority for approval to submit. The DA will then instruct as to which address the data is to be sent.**
- **NOTE: South Australian Government also requires hard copies for all reports**

TABLE 3: 3D SEISMIC DATA

DATA REQUIRED	REPORT TYPE	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Field Data						
Final Processed Navigation data Includes elevation and bathymetry data.	Documentary	UKOOA	TP	To be forwarded to GA after approval of TP by State	18 months after completion of acquisition.	All associated data sufficient to re-process seismic data including shot and receiver coordinates. See Appendix 3.1 for example.
Raw Navigation data	Documentary	UKOOA	TP	To be forwarded to GA after approval of TP by State	18 months after completion of the acquisition	P2/94 or subsequent format.
Seismic field data	Documentary	SEG Standard	TP	To be forwarded to GA after approval of TP by State	18 months after completion of acquisition	To be submitted on high density media.
Seismic support data	Documentary	PDF	TP	To be forwarded to GA after approval of TP by State	18 months after completion of acquisition	Must include observer's logs For onshore/OBC data only: surveyors notes, chaining diagrams, intersections, SPS files
Uphole data (onshore)	Documentary	ASCII	One copy	No	18 months after completion of acquisition	Includes line number, shotpoint and time depth pairs for each uphole.
Itemised field tape listing	Documentary	ASCII	One copy only to be submitted to State DA	State to forward copy to GA	18 months after completion of acquisition	Showing tape number, survey name, line number, shotpoint range, data type in ASCII format.

Processed Data						
Raw stacked data, near/mid/far sub-stacks - if generated	Documentary	SEG- Y	TP	To be forwarded to GA after approval of TP by State	18 months after completion of acquisition	Includes fully annotated EBCDIC header.
Raw and final migrated data including PSDM / PSTM, near/mid/far sub-stacks - if generated	Documentary	SEG-Y	One copy	One copy	18 months after completion of acquisition	Includes fully annotated EBCDIC header.
Final processed (grid) bin coordinates	Documentary	UKOOA 3D binning grids	One copy	One copy	18 months after completion of acquisition	See Appendix 3.2 for example.
Polygonal position data (Full Fold Outline for offshore; Full Fold Outline and Surface Outline for onshore)	Documentary	ASCII tab delimited	One copy	One copy	18 months after completion of acquisition	Listing major inflection points of a polygon describing the location of the survey providing survey name, polygon point, inline/crossline nomenclature, latitude and longitude. See Appendix 3.3 for example
Velocity data	Documen-tary	ASCII (Western Format)	One copy	One copy	18 months after completion of acquisition	Including bin number and time versus RMS velocity pair for both stacked and migrated velocities.
2D data subset (non-exclusive surveys)	Documentary	SEG-Y	One copy	One copy	18 months after completion of acquisition	Final migrated data.
Itemised process tape listing	Documentary	ASCII	One copy	One copy	18 months after completion of acquisition	Showing tape number, survey name, in-lines and crosslines, cdps, data type.
Final Reports						
Final report (operations and navigation)	Documentary	PDF	One copy	One copy	18 months after completion of acquisition	Location map included. Operations and Navigation Reports can be supplied as separate volumes. Onboard processing and any retained outputs to be documented in report.
Final processing report including grid definition	Documentary	PDF	One copy	One copy	18 months after completion of acquisition	To include sample print out of SEGY EBCDIC header, 3D grid definition details used for loading SEGY into interpretation work stations. See Appendix 3.3 for example
Final interpretation report	Derivative	PDF	One copy	One copy	18 months after completion of acquisition	
Digital images of interpretation maps	Derivative	TIF	One copy	One copy	18 months after completion of acquisition	These include TWT structure maps at key horizons and representative sections showing seismic horizon picks as Georeferenced TIF images.

- **TP: Transfer proposals to be sent to the Designated Authority for approval to submit. The DA will then instruct as to which address the data is to be sent.**
- **NOTE: South Australian Government also requires hard copies for all reports.**

TABLE 4: GRAVITY AND MAGNETIC SURVEY DATA

DATA REQUIRED	REPORT TYPE	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Field Data						
Aeromagnetic located field data	Documentary	ASCII columns	One copy	One copy	6 months after completion of survey	Must include: descriptive headers, flight number, line number, date and time, fiducial, raw magnetic reading, processed magnetic reading, radar and GPS or barometric altimeter, and base station reading. All coordinate data must also include clearly stated datum, spheroid and projection also clearly stated transformation parameters if not in same coordinate system as was acquired in the field.
Gravity field data	Documentary	ASCII columns	One copy	One copy	6 months after completion of survey	Including raw loop data, raw elevations plus measurement times and dates.. All coordinate data must also include clearly stated datum, spheroid and projection, clearly stated transformation parameters if not in same coordinate system as was acquired in the field. All elevation values must be AHD.
Altimeter, storm monitor, etc. (aeromagnetic only)	Documentary	ASCII (appropriate format)	One copy	No	6 months after completion of survey	One copy of analog monitor records, diurnal records and altimeter records in an appropriate format.
Other types of surveys	Documentary	See remarks	See remarks		See remarks	Submission and format details to be negotiated with the Designated Authority

NOTE: South Australia requires only the final processed gravity and magnetic data. As well, SA requires all reports in hardcopy.

Processed Data						
Field and processed data	Documentary	ASCII	One copy	One copy	6 months after completion of survey	ASCII data includes ASEG- GDF2 format.
Aeromagnetic processed data	Documentary	ASCII GDF2	One copy	One copy	6 months after completion of survey	Including pre and post microlevelling data. All coordinate data must also include clearly stated datum, spheroid and projection also clearly stated transformation parameters if not in same coordinate system as acquired in the field.
Gravity processed data	Documentary	ASCII GDF2	One copy	One copy	6 months after completion of survey	Data must include: descriptive headers, station, XY lat/long coordinates, meter reading, observed gravity value, elevation value calculation errors, final processed gravity value. All coordinate data must also include clearly stated datum, spheroid and projection, also clearly stated transformation parameters if not in same coordinate system as acquired in the field. All elevation values must be AHD.
Geophysical images	Documentary	PDF	One copy	One copy	6 months after completion of survey	

Final Reports						
Final report (operations, navigation and processing)	Documentary	PDF	One copy	One copy	6 months after completion of the survey	Must include location map and flight line map. Aeromagnetic surveys: Including aircraft and survey equipment details and specifications, flight line directions and terrain clearance, line spacing, total line kilometres. Gravity surveys: Including meter type, scale factor for meter. Data must be tied to an Isogal station in the Australian Fundamental Gravity Network. Processing report must include company details and processing parameters.

Final interpretation report	Derivative	PDF	One copy	One copy	6 months after completion of processing	
Digital images of interpretation maps	Derivative	TIF	One copy	One copy	6 months after completion of processing	These include any maps included in the Interpretation report as separate Georeferenced TIF images.

TABLE 5: REPROCESSED SEISMIC DATA

DATA REQUIRED	REPORT TYPE	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Processed Data						
Raw stacked data 2D and 3D, near/mid/far sub-stacks – if generated	Documentary	SEG-Y	One copy	One copy	Not later than the end of the title year in which the information was created.	Outputs must be in formats as specified in Tables 2 and 3.
Raw and final migrated data including PSDM / PSTM (2D and 3D), near/mid/far sub-stacks - if generated	Documentary	SEG-Y	One copy	One copy	Not later than the end of the title year in which the information was created.	Outputs must be in formats as specified in Tables 2 and 3.
Final processed (grid) bin coordinates	Documentary	UKOOA 3D binning grids	One copy	One copy	Not later than the end of the title year in which the information was created.	To be completed using UKOOA See Appendix 3.2 for example
Polygonal positions for 3D data (Full Fold Outline for offshore; Full Fold Outline and Surface Outline for onshore)	Documentary	ASCII tab delimited	One copy	One copy	Not later than the end of the title year in which the information was created.	Listing major inflection points of a polygon describing the location of the survey providing survey name, polygon point, inline/crossline nomenclature, latitude and longitude. See Appendix 3.3 for example.
Itemised tape listing	Documentary	ASCII Plus Hardcopy for South Australia	One copy	One copy	Not later than the end of the title year in which the information was created.	Showing the tape number, survey name, line number, shotpoint, data-type and what original tapes are on the copy tapes.
Fully annotated image of final reprocessed migrated data. (Onshore only)	Documentary	See Appendix 2.2	One copy only to be submitted to State DA	No required	Not later than the end of the title year in which the information was created.	The image must have a vertical scale of not less than 5cm/sec. See Appendix 2.2 for details of requirements for relevant States.
Velocity data	Documentary	ASCII (Western format)	One copy	One copy	Not later than the end of the title year in which the information was created.	Include line number, shotpoint, Time versus RMS pairs for both stacked and migrated velocities.

Final Reports						
Final report (Reprocessing)	Documentary	PDF Plus Hardcopy for South Australia	One copy	One copy	12 months after the end of permit year in which processing was completed	Outputs must be in formats as specified in Tables 2 and 3.
Final report (Interpretive)	Derivative	PDF Plus Hardcopy for South Australia	One copy	One copy	12 months after the end of permit year in which processing was completed	Geo-referenced TIF to include TWT structure maps at key horizons and representative sections showing seismic horizon picks.
Digital images of interpretation maps	Derivative	TIF	One copy	One copy	12 months after completion of processing	These include TWT structure maps at key horizons and representative sections showing seismic horizon picks as Georeferenced TIF images.

TABLE 6: NOTIFICATION OF DISCOVERY, MONTHLY PRODUCTION RATE AND WIRELINE SURVEY REPORTS, TITLE AREA REPORTS, FIELD DEVELOPMENT PLANS

DATA REQUIRED	REPORT TYPE*	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Notification of discovery	Documentary	PDF	One copy	One copy	3 days after discovery	See section 34 of PSLA
Title assessment report - initial following discovery (including preliminary estimates of petroleum-in-place)	Derivative	PDF	One copy	One copy	Within 3 months of date of discovery	Would replace clause 550(1) of current directions
Title assessment report - annual update (including revisions to petroleum-in-place)	Derivative	PDF	One copy	One copy	Updates-30th September of each year	Would replace 550(2)(3) and (4) of current directions
Monthly production rate report by well	Documentary	ASCII, XLS, PDF	One copy	One copy	15th day of next succeeding month	Example to be provided. Would replace clause 652 of current directions.
Monthly wireline surveys and subsurface safety valve reports	Documentary	PDF, PDS,META	One copy	One copy	15th day of next succeeding month	Example to be provided. Would replace clause 653 of current directions.
Preliminary Field Development Plan	Derivative	PDF and all maps in hardcopy at appropriate scale	One copy	One copy	As soon as possible after development planning commences	
Field Development Plan	Derivative	PDF and all maps in hardcopy at appropriate scale	One copy	One copy	With application for production licence	
Notification where new or increased risk to resource recovery is identified after consent to Field Development Plan	Derivative	PDF	One copy	One copy	Within three days after risk is identified	
Revision to Field Development Plan after new or increased risk to resource recovery is identified, not provided for in development plan in force	Derivative	PDF	One copy	One copy	As soon as possible after risk is identified, or as agreed with Designated Authority	

Update to Field Development Plan- after major change	Derivative	PDF and all maps in hardcopy at appropriate scale	One copy	One copy	Before seeking consent for major change to development plan	
Update of Field Development Plan–after 5 years	Derivative	PDF and all maps in hardcopy at appropriate scale	One copy	One copy	5 years after previous agreed Field Development Plan	
Update of Field Development Plan– prior to cessation of production	Derivative	PDF and all maps in hardcopy at appropriate scale	One copy	One copy	Before seeking consent for cessation of production	See decommissioning guidelines

*** REPORT TYPE column refers to the type of information required. Previous to the 2000 amendment of the Petroleum (Submerged Land Act) 1967, Section 118 and the Guidelines supporting the Schedule of the Specific Requirements under the P(SL)A, reference was made in respect of Basic and Non-Basic (Interpretive) data types. Following the amendment of the P(SL)A 1967 in 2000 the previous Section 118 of the P(SL)A 1967 was re-defined in Section 150 and the data types defined as *Documentary and Petroleum Mining Sample* (previously referred to as BASIC) and *Derivative* (previously referred to as NON-BASIC or INTERPRETIVE).**

TABLE 7: DAILY, WEEKLY, QUARTERLY AND ANNUAL REPORTING

DATA REQUIRED	REPORT TYPE	FORMAT	DATA FOR STATE/ TERRITORY	DATA FOR FEDERAL GOVT. (GA)	DATE FOR SUBMISSION (prior to or by)	REMARKS
Daily reports for wells	Documentary	PDF	One copy	One copy	By midday of the day after the day to which the report relates.	Must comply with Regulation 201 – see section 12 of Guidelines. Emailed to addresses designated by DA.
Daily logs for wells	Documentary	PDF, PDS, META	One copy	One copy	By midday of the day after the day to which the logs relate.	Emailed to addresses designated by DA.
Weekly reports for surveys	Documentary	PDF	One copy	One copy	As soon as practicable after the end of the week to which the report relates	Must comply with Regulation 202 – see section 13 of Guidelines. Emailed to addresses designated by DA.
Quarterly reports for exploration permits	Documentary	PDF	One copy	One copy	No later than one month after the end of the quarter to which the report relates	Must comply with Regulation 204 – see section 15a of Guidelines. Emailed or delivered to addresses designated by DA.
Annual reports for exploration permits and retention leases	Documentary	PDF	One copy	One copy	No later than one month after the end of the title year to which the report relates	Must comply with Regulation 205 – see section 16 of Guidelines. Emailed or delivered to addresses designated by DA.
Annual reports for production licences	Documentary	PDF	One copy	One copy	In the month of September or other nominated month by the DA	Must comply with Schedule 650 - 651 – see section 16b of Guidelines. Emailed or delivered to addresses designated by DA.

Transfer Proposal Form for

OFFSHORE PETROLEUM DATA

1. Name of company lodging data

ACN:

2. Address and contact number of company

(Postcode)

Phone (___) Fax (___)

3. Name of contact officer

4. Signature of person authorised to deposit

Signature Date __/__/__

Number of boxes
(Boxes must weigh no more than 16 kg)

5. Survey Details

Name of Survey:

State / Territory of Survey:

6. Summary of Submission

• **Type**	• **Medium**	• **Quantity**
• Field Seismic Data	•	•
• Processed Seismic	•	•
• Observers' Reports	•	•
• Navigation Data	•	•
• Well Logs	•	•
• Other Material		

To be completed by the Designated Authority

Print Name

Position

Phone ( ) Fax ( )

Signature ____/____/____ Date

(Must be signed by Designated Authority Delegate)

Designated Authority Reference

ADVICE TO SUBMITTERS OF DATA

For data other than seismic field data, send this form with the data to the relevant state Designated Authority.

For seismic field data send this form to the State Designated Authority and GA Data Repositories will contact you with regard to shipment of the data.

Alternatively, submitters may use the on-line form on GA's web site. GA Data Repositories will send the information to the relevant Designated Authority and will arrange shipment.

A consignment list is required with the data. A template is available as an EXCEL spreadsheet on GA's web site.

All these forms are available from Geoscience Australia web site www.ga.gov.au.

Appendix 1
Requirements for the submission of Palynology Slides for Victoria

Victoria requires that Biostratigraphic (including Palynology) Slides or residues be submitted to the National Museum in Melbourne according to the P-numbering requirements desried by the Melbourne Museum. We require that companies submitting palynological / biostratigraphic slides make sure that they:

1. obtain a valid range of Museum of Victoria unique "P" catalogue numbers form the Melbourne Museum
2. label the palynological slides with these P numbers, preferably on the slide itself in indelible ink rather than on a sticker
3. submit a full biostratigraphic reports to the Victorian DA
4. catalogue these sildes and submit TO THE Victorian DA, a digital ASCII catalogue of the slides showing
    1. unique Museum P Number
    2. well name
    3. sample type (core / cuttings / swc)
    4. the original core number of side wall core number (if applicable)
    5. depth point value
    6. depth range (if applicable)
    7. slide type (e.g. kerogen, oxidised etc)
    8. other descriptive details
    9. remarks, including any further processing (e.g. sieve size) or identification

Appendix 2
Examples of data submission requirements for Table 2 - 2D Seismic data

Appendix 2.1

Example of Navigation required for Table 2.

```
H0100SURVEY AREA                2D MSS,  AC/P30 ,  BROWSE BASIN, NW SHELF
H0102VESSEL DETAILS             ACADIAN SEARCHER           1
H0103SOURCE DETAILS             BOLT 3200 CU IN ARRAY      1   1
H0104STREAMER DETAILS           SYNTRAK 480-24 RDA         1       1
H0200DATE OF SURVEY             19990119-19990227
H0201DATE OF ISSUE OF TAPE      31-Mar-1999
H0202TAPE VERSION IDENTIFIER    UKOOA P1/90
H0300CLIENT                     BHP PETROLEUM (AUSTRALIA) PTY LTD
H0400GEOPHYSICAL CONTRACTOR     VERITAS DGC AUSTRALIA PTY. LTD
H0500POSITIONING CONTRACTOR     FUGRO SURVEY PTY LTD
H0600POSITIONING PROCESSING     SPRINT
H0700POSITIONING SYSTEM         VESSEL_1 SPECTRA MRDGPS DGPS
H0800COORDINATE SYSTEM          CMP AT SHOTPOINT
H0900OFFSET SYSTEM TO CMP          1   2    0.00 -147.13
H0901OFFSET SYSTEM TO GPS SECOND   1   2   -0.20   -0.20
H0902OFFSET SYSTEM TO GPS PRIME    1   2   -0.70    0.40
H0903OFFSET SYSTEM TO STERN        1   2    0.00  -45.50
H0904OFFSET SYSTEM TO SOURCE       1   2    0.00  -87.46
H0905OFFSET SYSTEM TO CNG          1   2    0.00 -206.80
H1000CLOCK TIME                 GMT 0.000
H1100RECEIVER GROUPS PER SHOT   480
H1400GEODETIC DATUM AS SURVEY   AGD 84      Australian N 6378160.000 298.2500000
H1500GEODETIC DATUM FOR POST.   AGD 84      Australian N 6378160.000 298.2500000
H1700VERTICAL DATUM             MSL                    : ECHOSOUNDER
H1800PROJECTION                    2UNIVERSAL TRANSVERSE MERCATOR
H1900ZONE                       51  SOUTHERN ORIENTATED
H2000GRID UNITS                 1INTERNATIONAL METERS     1.000000000000
H2001HEIGHT UNITS               1INTERNATIONAL METER      1.000000000000
H2301GRID ORIGIN                  0 0 0.000N123 0 0.000E
H2302GRID COORDINATES             500000.00E10000000.00N
H2401SCALE FACTOR               0.9996000000
H2600  IN THE SEG-D HEADERS AND ON AUTOMATIC TAPE LABELING THE SURVEY NAME WAS
H2600  TRUNCATED TO 4 CHARACTERS, I.E. FROM HBR1998B- TO HBRB- TO FIT INTO
H2600  8 CHARACTERS
H2600DEPTH DATA REDUCTION       CORRECTED FOR TRANSDUCER DEPTH
H2600DEPTH DATA REDUCTION       TIDAL CORRECTIONS APPLIED USING BHP PROVIDED
H2600DEPTH DATA REDUCTION       TIDE-TABLE FOR AC/P30.
H2600DEPTH DATA REDUCTION       ECHOSOUNDER VEL/P AT 1509 M/S
H2600COMPASSES        EXTERNAL, SELF BIASING, DIGICOURSE 318/321 IN 5011 BIRDS
H2600TAILBUOY                   NON ACTIVE
H2600SHOT RECORD DESCRIPTION    V=VESSEL REF POINT
H2600SHOT RECORD DESCRIPTION    E=ECHOSOUNDER POSITION
H2600SHOT RECORD DESCRIPTION    S=CENTRE OF SOURCE
H2600SHOT RECORD DESCRIPTION    C=NEAR CMP
H2600 Line HBR1998B-02               From Shot 3437 To Shot  881
VHBR1998B-02    1    3437131957.15S1224314.13E 469741.38526067.1 453.9 56 95128
EHBR1998B-02    1    3437131957.29S1224314.53E 469753.18526063.0 453.9 56 95128
SHBR1998B-02    11   3437131958.44S1224316.72E 469819.38526027.6 453.9 56 95128
CHBR1998B-02    111  3437131959.39S1224318.45E 469871.48525998.6 453.9 56 95128
VHBR1998B-02    1    3436131956.66S1224313.46E 469721.08526082.3 453.7 56 95138
EHBR1998B-02    1    3436131956.79S1224313.85E 469732.98526078.4 453.7 56 95138
SHBR1998B-02    11   3436131957.92S1224316.06E 469799.38526043.5 453.7 56 95138
CHBR1998B-02    111  3436131958.87S1224317.79E 469851.58526014.5 453.7 56 95138
VHBR1998B-02    1    3435131956.23S1224312.79E 469700.98526095.5 454.0 56 95148
```

Appendix 2.2

Requirements for seismic section image data for individual States for Table 2.

State	Type	Format
New South Wales	Digital	CGM+
Northern Territory	Digital	Tif
Queensland	Digital	CGM
South Australia	Digital	Tif
Tasmania	Digital	Tif
Victoria	Digital	CGM+ / PDF / tif
Western Australia	Digital	PDF / CGM+

Appendix 3
Examples of data submission requirements for Table 3 - 3D Seismic data

Appendix 3.1 Field navigation

```
H01  SURVEY AREA              HV11 TIMOR SEA AUSTRALIA
H02  SURVEY YEAR              1990
H021 DATE OF TAPE             08/31/90
H022 TAPE DENSITY             6250
H03  CLIENT                BHP AUSTRALIA
H04  GEOPHYSICAL CONTRACTOR     GECO GEOPHYSICAL CO. SFE
H05  POSITIONING CONTRACTOR     ONI
H06  NAV. PROCESSING CONTR.     GECO GEOPHYSICAL CO. NSA
H07  NAVIGATION SYSTEM          SPOT
H08  COORDINATE LOCATION        SOURCE AND RECIEVER POSITIONS
H090 OFFSET-SYSTEM TO COORDS    ANTENNA TO 1ST GRP = 229.0 METERS
H091 OFFSET-SYSTEM TO COORDS    SOURCE TO 1ST GRP = 133.0 M.
H10  CLOCK TIME               G.M.T.
H11  NR. OF RECEIVERS           480
H11  NR. OF STREAMERS           TWO
H111 NUMBERING OF RECIEVERS     CABLE 1   REC#   1-240   STARBOARD
H111 NUMBERING OF RECIEVERS     CABLE 2   REC# 241-480   PORT
H12  SURVEY SPHEROID          AUSTRALIAN NATIONAL      6378160.000 298.2500000
H13  POST PLOT SPHEROID       AUSTRALIAN NATIONAL      6378160.000 298.2500000
H14  SURVEY DATUM             AGD 66
H15  POST PLOT DATUM          AGD 66
H160 DATUM SHIFT:             PARAMETER FROM SURVEY TO POSTPLOT DATUM
H161 SHIFT CONSTANTS:(METERS)   DX=   00.00  DY=  00.00  DZ=  00.00
H161                       XROT=  0.00  YROT=  0.00  ZROT= 0.00
H161                       DIMENSIONLESS SCALE FACTOR = 0.000 PPM
H17  VERTICAL :               SEA LEVEL
H18  PROJECTION:              TRANSVERSE MERCATOR
H19  PROJECTION ZONE:         UTM ZONE NO.51  SOUTHERN HEMISPHERE
H20  GRID UNIT:               METER
H220 CENTRAL MERIDIAN:        1230000.000E
H231 ORIGIN:                0000000.000 1230000.000E
H232 FALSE EASTING,NORTHING     10000000.00N  500000.00E
H241 SCALE FACTOR:            0.9996
H242 LONG. AT SCALE FACTOR:     1230000.000E
H26 COMMENTS: FINAL NAV OUTPUT WITH ONE SOURCE POSITION FOLLOWED BY 240
H26 COMMENTS: STARBOARD AND 240 PORT RECIEVER POSITIONS
SHV11-121           689123231.80S1242745.77E  6589207 86130480  89.4194232733
R   1  6590463 86129820      2  6590546 86129730      3  6590629 86129630
R   4  6590712 86129540      5  6590795 86129450      6  6590878 86129350
R   7  6590961 86129260      8  6591044 86129170      9  6591128 86129070
R  10  6591211 86128980     11  6591294 86128890     12  6591377 86128790
R  13  6591460 86128700     14  6591543 86128610     15  6591627 86128510
R  16  6591710 86128420     17  6591793 86128330     18  6591876 86128230
R  19  6591959 86128140     20  6592043 86128050     21  6592126 86127950
R  22  6592209 86127860     23  6592293 86127770     24  6592376 86127670
R  25  6592459 86127580     26  6592543 86127490     27  6592626 86127390
R  28  6592709 86127300     29  6592793 86127210     30  6592876 86127110
R  31  6592959 86127020     32  6593043 86126930     33  6593126 86126840
R  34  6593209 86126740     35  6593293 86126650     36  6593376 86126560
R  37  6593459 86126460     38  6593543 86126370     39  6593626 86126280
R  40  6593709 86126180     41  6593793 86126090     42  6593876 86126000
R  43  6593960 86125900     44  6594043 86125810     45  6594127 86125720
R  46  6594210 86125620     47  6594294 86125530     48  6594377 86125440
R  49  6594461 86125350     50  6594544 86125250     51  6594628 86125160
R  52  6594711 86125070     53  6594794 86124970     54  6594878 86124880
R  55  6594961 86124790     56  6595044 86124690     57  6595128 86124600
R  58  6595211 86124510     59  6595294 86124410     60  6595378 86124320
R  61  6595461 86124230     62  6595545 86124140     63  6595628 86124040
R  64  6595711 86123950     65  6595795 86123860     66  6595878 86123760
```

Appendix 3.2

Sample post-binning navigation file for 3D Seismic data.

```
H0100 SURVEY & AREA NAME        HB96B, BUFFALO                  130396
H0101 GENERAL SURVEY DETAILS    DUAL CABLE, DUAL SOURCE 3D SURVEY
H0102 VESSEL DETAILS            WESTERN HORIZON P131       1
H0103 SOURCE DETAILS            N/A
H0104 STREAMER DETAILS          N/A
H0200 DATE OF SURVEY            MARCH TO MAY 1996
H0201 POSTPLOT DATE             23 DECMBER 1996
H0202 TAPE VERSION              UKOOA-P1/1990 (WESTERN VERSION 01.01)
H0300 CLIENT NAME               B.H.P.
H0400 GEOPHYSICAL CONTRACTOR    Western Geophysical.
H0500 POSITIONING CONTRACTOR    Western Geophysical.
H0600 PROCESSING CONTRACTOR     WESTERN ATLAS INTERNATIONAL
H0700 POSITIONING SYSTEM        WISDOM (TM) INTEGRATED NAV SYSTEM
H0800 COORDINATE LOCATION       STACK TRACE CENTRE OF BIN
H0900 POSITION OFFSETS          N/A
H1000 CLOCK TIME                GMT + 0 HOURS
H1100 RECEIVER GROUPS PER SHOT   480
H1400 GEODETIC DATUM AS SURVEYEDAGD-84      AUSTRALIAN N 6378160.000 298.2500000
H1401 TRANSFORMATION PARAMETERS -116.0 -50.5 141.7 -.230 -.390 -.344  .0983000
H1500 GEODETIC DATUM AS PLOTTED AGD-84      AUSTRALIAN N 6378160.000 298.2500000
H1501 TRANSFORMATION PARAMETERS -116.0 -50.5 141.7 -.230 -.390 -.344  .0983000
H1600 DATUM SHIFTS                  .0    .0    .0  .000  .000  .000  .0000000
H1700 VERTICAL DATUM            MEAN SEA LEVEL          ECHO SOUNDER
H1800 PROJECTION TYPE            002UNIVERSAL TRANSVERSE MERCATOR
H1900 UTM ZONE                  52S
H2000 GRID UNITS                1METERS                   1.000000000000
H2001 HEIGHT UNITS              1METRES                   1.000000000000
H2002 ANGULAR UNITS             1DEGREES
H2200 CENTRAL MERIDIAN          129 0  .000E
H2301 GRID ORIGIN                 0 0  .000N129 0  .000E
H2302 GRID COORDINATES AT ORIGIN  500000.00E10000000.00N
H2401 SCALE FACTOR               .9996000000
H2402 SCALE FACTOR DEFINED AT     0 0  .000N129 0  .000E
H2600
H2600 DATUM ROTATION PARAMETERS ARE EXPRESSED IN COORDINATE FRAME SENSE
H2600
QHB96-10000          1900104642.22S1255821.88E 168901.08806882.5 528.2
QHB96-10000          1901104641.89S1255821.89E 168901.08806892.5 528.2
QHB96-10000          1902104641.57S1255821.89E 168901.08806902.5 529.8
QHB96-10000          1903104641.24S1255821.89E 168901.08806912.5 529.8
QHB96-10000          1904104640.92S1255821.89E 168901.08806922.5 529.8
QHB96-10000          1905104640.59S1255821.90E 168901.08806932.5 529.8
QHB96-10000          1906104640.27S1255821.90E 168901.08806942.5 529.8
QHB96-10000          1907104639.94S1255821.90E 168901.08806952.5 529.8
QHB96-10000          1908104639.62S1255821.91E 168901.08806962.5 529.8
QHB96-10000          1909104639.29S1255821.91E 168901.08806972.5 529.8
QHB96-10000          1910104638.97S1255821.91E 168901.08806982.5 529.8
QHB96-10000          1911104638.64S1255821.92E 168901.08806992.5 529.8
QHB96-10000          1912104638.32S1255821.92E 168901.08807002.5 529.8
QHB96-10000          1913104637.99S1255821.92E 168901.08807012.5 529.8
QHB96-10000          1914104637.67S1255821.93E 168901.08807022.5 529.8
QHB96-10000          1915104637.34S1255821.93E 168901.08807032.5 529.8
```

Appendix 3.3

Example of polygon position data and Processing Report inclusion required for Table 3 - 3D data.

Grid Definitions

Datum	AGD-84				
Spheroid	ANS	Semi-major axis			6378160.000
		Semi-minor axis			6356774.719
		Inverse flattening			298.25000
		Eccentricity			0.006694
Projection	UTM	Central meridian			120.00
		Scale factor			0.99600
		False Easting			50000.00
		False Northing			10000000.00

Datum shift from WGS-84 to LOCAL

dX	+116.0000	rX	-0.230000
dY	+050.4700	rY	-0.390000
dZ	500000.00	rZ	-0.344000
Scale	-0098300000		

Navigation origin	Easting	636744.95
(inline 1001 crossline 1001)	Northing	8473164.88
	Latitude	13 48 28.060 S
	Longitude	124 15 540447 E

Processing grid

CDP spacing	12.5m
CDP increment	1.0
Line spacing	12.5m
Line increment	1.0

Prospect angle 40.005000 degrees

Corner points of the grid

X-coords	Y-coords	Inline	Crossline
635870.41	8472619.28	981	921
686385.321	8524919.867	981	6738
663634.5862	8445803.044	4069	921
714149.4973	8498103.631	4069	6738

Total number of cells 17971802