§ 203.84 What is in a net revenue and relief justification report?

This report presents cash flow data for 12 qualifying months, using the format specified in the “Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases”, U.S. Department of the Interior, BSEE. Qualifying months for an oil and gas lease are the most recent 12 months out of the last 15 months that you produced at least 100 BOE per day on average. Qualifying months for other than oil and gas leases are the most recent 12 of the last 15 months having some production.

(a) The cash flow table you submit must include historical data for:
   (1) Lease production subject to royalty;
   (2) Total revenues;
   (3) Royalty payments out of production;
   (4) Total allowable costs; and
   (5) Transportation and processing costs.

(b) Do not include in your cash flow table the non-allowable costs listed at 30 CFR 1220.013 or:
   (1) OCS rental payments on the lease(s) in the application;
   (2) Damages and losses;
   (3) Taxes;
   (4) Any costs associated with exploratory activities;
   (5) Civil or criminal fines or penalties;
   (6) Fees for your royalty relief application; and
   (7) Costs associated with existing obligations (e.g., royalty overrides or other forms of payment for acquiring the lease, depreciation on previously acquired equipment or facilities).

(c) We may, in reviewing and evaluating your application, disallow costs when you have not shown they are necessary to operate the lease, or if they are inconsistent with end-of-life operations.

§ 203.85 What is in an economic viability and relief justification report?

This report should show that your project appears economic without royalties and sunk costs using the RSVP model we provide. The format of the report and the assumptions and parameters we specify are found in the “Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program,” U.S. Department of the Interior, BSEE. Clearly justify each parameter you set in every scenario you specify in the RSVP. You may provide supplemental information, including your own model and results. The economic viability and relief justification report must contain the following items for an oil and gas lease.

(a) Economic assumptions we provide which include:
   (1) Starting oil and gas prices;
   (2) Real price growth;
   (3) Real cost growth or decline rate, if any;
   (4) Base year;
   (5) Range of discount rates; and
   (6) Tax rate (for use in determining after-tax sunk costs).

(b) Analysis of projected cash flow (from the date of the application using annual totals and constant dollar values) which shows:
   (1) Oil and gas production;
   (2) Total revenues;
   (3) Capital expenditures;
   (4) Operating costs;
   (5) Transportation costs; and
   (6) Before-tax net cash flow without royalties, overrides, sunk costs, and ineligible costs.

(c) Discounted values which include:
   (1) Discount rate used (selected from within the range we specify).
   (2) Before-tax net present value without royalties, overrides, sunk costs, and ineligible costs.

(d) Demonstrations that:
   (1) All costs, gross production, and scheduling are consistent with the data in the G&G, engineering, production, and cost reports (§§ 203.86 through 203.89) and
(2) The development and production scenarios provided in the various reports are consistent with each other and with the proposed development system. You can use up to three scenarios (conservative, most likely, and optimistic), but you must link each to a specific range on the distribution of resources from the RSVP Resource Module.

§ 203.86 What is in a G&G report?

This report supports the reserve and resource estimates used in the economic evaluation and must contain each of the following elements.

(a) Seismic data which includes:

(1) Non-interpreted 2D/3D survey lines reflecting any available state-of-the-art processing technique in a format readable by BSEE and specified by the deep water royalty relief guidelines;

(2) Interpreted 2D/3D seismic survey lines reflecting any available state-of-the-art processing technique identifying all known and prospective pay horizons, wells, and fault cuts;

(3) Digital velocity surveys in the format of the GOM region’s letter to lessees of 10/1/90;

(4) Plat map of “shot points;” and

(5) “Time slices” of potential horizons.

(b) Well data which includes:

(1) Hard copies of all well logs in which—

(i) The 1-inch electric log shows pay zones and pay counts and lithologic and paleo correlation markers at least every 500-feet,

(ii) The 1-inch type log shows missing sections from other logs where faulting occurs,

(iii) The 5-inch electric log shows pay zones and pay counts and labeled points used in establishing resistivity of the formation, 100 percent water saturated ($R_w$) and the resistivity of the undisturbed formation ($R_o$), and

(iv) The 5-inch porosity logs show pay zones and pay counts and labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time;

(2) Digital copies of all well logs spudded before December 1, 1995;

(3) Core data, if available;

(4) Well correlation sections;

(5) Pressure data;

(6) Production test results;

(7) Pressure-volume-temperature analysis, if available; and

(8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) Map interpretations which includes for each reservoir in the field:

(1) Structure maps consisting of top and base of sand maps showing well and seismic shot point locations;

(2) Isopach maps for net sand, net oil, net gas, all with well locations;

(3) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and

(4) An explanation for excluding the reservoirs you are not planning to develop.

(d) Reservoir-specific data which includes:

(1) Probability of reservoir occurrence with hydrocarbons;

(2) Probability the hydrocarbon in the reservoir is all oil and the probability it is all gas;

(3) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for the parameters used to estimate reservoir size, i.e., acres and net thickness;

(4) Most likely values for porosity, salt water saturation, volume factor for oil formation, and volume factor for gas formation;

(5) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for recovery efficiency (in percent) and oil or gas recovery (in stock-tank-barrels per acre-foot or in thousands of cubic feet per acre foot);

(6) A gas/oil ratio distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each reservoir;

(7) A yield distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each gas reservoir; and