Reserves Certification Report
for the
Rubiales Field, Colombia

Prepared For:
Metapetroleum LTD

February 2010

RPS

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February 9, 2010

Meta Petroleum Ltd.
Calle 113 #7-80
Torre AR, Piso 13
Bogota, Columbia

Attention: Ysidro Araujo, Reservoir Manager

Re: Meta Petroleum Rubiales Field Reserve Evaluation

Dear Mr. Araujo,

As requested, RPS has completed the evaluation of Meta Petroleum's Rubiales oil field assets as of December 31, 2009 and submit the attached report. The assets evaluated consist of the Rubiales field only in Columbia.

The evaluation was conducted using the guidelines of the Canadian Oil and Gas Evaluation Handbook, and is consistent with the reporting requirements listed in the Canadian National Instrument 51-101. The Rubiales field has been evaluated at the Proved Developed Producing , Proved Developed Non Producing, Proved Undeveloped, Probable and Possible oil and gas reserves levels. Additionally, production volumes beyond the concession expiry in 2016 and resource volumes which lie outside the mapped reserves areas have been included.

We appreciate the opportunity to conduct this reserves evaluation for you and trust that the attached report meets your requirements.

Yours sincerely,
RPS Energy

Brian Weatherill, P.Eng.
Reservoir Evaluations Specialist

PROFESSIONAL ENGINEER
BRIAN D. WEATHERILL
ALBERTA

PERMIT TO PRACTICE
RPS ENERGY CANADA LTD.
Signature
Date 2010-02-09
PERMIT NUMBER: P4348
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

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1.0 EXECUTIVE SUMMARY

RPS was engaged by Meta Petroleum Corporation (Meta) to perform a reserves certification report effective December 31, 2009. The field has produced for a number of years and has a significant reserves base remaining. An aggressive drilling program has been pursued to develop the majority of the remaining reserves prior to the expiration of the Rubiales and Piriri concessions. Given the reservoir performance to date and the associated development plan, the drilling program should continue to be successful and oil production will increase considerably as the work proceeds.

All reserves volumes in the field are categorized as proved, probable or possible based on the definitions in the Petroleum Resource Management System of the Society of Petroleum Engineers. Many of the wells to be drilled are in the probable and possible categories some distance from the currently developed area; those volumes are unrisked in this report as is the value placed on those volumes. The present value of the reserves was calculated at a ten percent discount rate using a price forecast developed by the Strategic Planning Department of RPS in London. All costs associated with the development of the reserves, including drilling, infrastructure and water disposal wells are included.

The table below provides a summary of the reserves and value by each reserves category.

Reserves Category	Field Gross Reserves MMbbl	Meta Working Interest Reserves MMbbl		NPV @ 10% $MM US	
		Gross	Net	BFIT	AFIT
Proved					
Developed Producing	94.1	41.6	33.3	1,420.2	980.3
Developed Non-Producing	27.1	11.4	9.1	314.8	225.1
Undeveloped	296.0	125.5	100.4	3,546.5	2,555.1
Total Proved	417.2	178.6	142.9	5,281.5	3,760.5
Probable	46.0	19.0	15.2	508.5	368.7
Total Proved + Probable	463.2	197.6	158.1	5,790.0	4,129.2
Possible	38.0	16.1	12.9	415.5	288.3
Total Pvd + Prob + Poss	501.2	213.7	171.0	6,205.5	4,417.5

RPS has updated the mapping of oil initially in place (OIIP) for the field to a new total of 4,248 MMstb, up from 3,886 MMstb calculated as of year-end 2008. This represents an increase of 362 MMstb (9.3 percent) and is due to updated geological mapping using data from 2009 drilling and revised petrophysical analysis. Accounting for the 2009 production of 25.1 MMstb from the field, the year-end 2009 reserves represent an increase in estimated total concession date recovery of 146 MMstb at the proved level, and 90 MMstb at the proved and probable level.

The series of tables listed below show the results of the reserves, production, cash flow and present worth calculations:

Table 1.1	Summary of Oil and Gas Reserves – gross and net volumes
Table 1.2	Net Present Value of Future Net Revenue – BFIT & AFIT at various discount rates
Table 1.3	Total Future Net Revenue (Undiscounted) – revenue and cost cash flows
Table 1.4	Future Net Revenue by Production Group – BFIT NPV @ 10%
Table 1.5	Future Net Revenue (Unit Value Basis) by Production Group – BFIT NPV @ 10%
Table 1.6	Summary of Pricing and Inflation Rate Assumptions
Table 1.7	Summary of Estimated Development Costs Attributable to Reserves
Table 1.8	Summary of Production Estimates – Proved, Probable and Possible Categories

The field wide proved, probable and possible reserves volume is 501 million barrels (representing 11.8 percent of the oil initially in place) of which 83.2 percent is proved. Additional resources that were not included in the evaluation were identified in areas adjacent to the possible drilling locations and in outlying areas of lower thickness pay sand. The recovery potential of these resources and economically recoverable volumes beyond the concession expiry date is an additional 279 MMstb (6.6 percent OIIP). Coupled with the cumulative production to year-end 2009 of 57.6 MMstb (1.3 percent OIIP) the potential ultimate recovery is 838 MMstb for a total potential recovery of 19.7 percent OIIP.

All references to costs and values in the report are in United States dollars. The net present value reported is unrisked and does not represent the fair market value of Meta's ownership in the Rubiales Field. A site inspection of the field, including existing wells, facilities, tanks and pipelines as well as many major construction projects, was made on December 15, 2009. The data provided by Meta was the sole source of information for this report.

2.0 CONCLUSIONS

This reserves certification report was prepared using field data and an investment program as provided by Meta. The conclusions noted below relate to depletion of the existing wells and implementation of the field development plan as it has been proposed.

- The drilling campaigns in each of the past years have been very successful in finding and developing oil and in validating the geological model and engineering projections from earlier studies.

- Due to Meta's higher working interest, the Piriri concession reserves have more value to Meta than the reserves to be produced from the Rubiales concession.

- Certain step-out locations that were some distance from proved reserves have been drilled successfully, and as a result significant areas of the reservoir have had crude volumes re-categorized to proved reserves much sooner than if the drilling program been restricted to the proved undeveloped locations.

- Production and cash flow have been maximized since the pipeline capacity has been developed on schedule and the water disposal wells and facilities are being drilled and built as needed to avoid or minimize the curtailment of production due to transportation or processing limitations.

- The production can be developed for a relatively low cost per barrel. Adherence to the accelerated rig program will increase the recovery factor as high as it can be before the concession expires.

- An analysis of the historical drilling program results, in contrast to the remaining areas to be drilled, indicates that future drilling will result in lower recovery per well due to the thinning nature of the sand on the flanks of the structure.

3.0 FIELD OVERVIEW

3.1 Ownership

The Rubiales Field is located in the Llanos Basin on the eastern side of Columbia as shown in Figure 3.1, the “Location Map”. Meta’s working interest in the Rubiales Field is comprised of a 50% ownership in the Piriri concession (62,432 acres in size) and a 40% ownership in the Rubiales concession (88,463 acres in size). The boundaries of the properties are shown in Figure 3.2, the “Concession Map”. The Rubiales field is productive from 135,361 acres, which comprises the majority of the entire extent of the concession area of 150,895 acres.

Meta pays a 20% royalty on working interest production. There are no other burdens or overriding royalties associated with the concessions. The agreements expire on July 1, 2016. This relatively close expiry date is the incentive to Meta to develop the field quickly and produce field reserves as soon as possible.

3.2 Development History

The Rubiales field was discovered in 1981 by Exxon in association with the Tethys operating group. Three wells were drilled from 1981 to 1982 and on July 1, 1988 a 28 year concession was granted. Exxon then drilled 14 wells from 1988 to 1993. The field was then acquired by Coplex Resources in 1994 who drilled 5 additional wells by 1997. Due to financial problems within the company, the field was shut in until Tethys et al re-acquired it from Coplex in 2000. Production was re-started in 2001 and two additional wells were drilled for a total of 24 wells at that time.

In mid-2002 Rubiales Holdings acquired Tethys et al and quickly drilled 14 wells while improving field operations. In 2004 Meta Petroleum became the operator of the Rubiales field following a merger of the “et al” companies with the result being a 50% ownership in the Piriri concession and a 40% ownership in the Rubiales concession. In 2005, studies conducted by Meta confirmed the significant potential of the field and an investment program was approved.

From 2006 to the present Meta has conducted an aggressive drilling program that has resulted in a current total of 139 producing wells that are pumping approximately 102,000 barrels of oil per day at year end. During 2009, the field produced 25.1 MMstb of oil and at year-end had a cumulative production of 57.6 MMstb. The results of this program are indicated on the field production plot, Figure 3.3, and on the production plots for the Rubiales and Piriri concessions on Figures 3.4 and 3.5, respectively. As of year-end 2009, in the fully developed areas of the field, the wells have been drilled on an average spacing of 81 acres. At year-end 2009, the field had the following well count:

Production	Vertical	38
	Horizontal	101
Disposal	Vertical	3
	Horizontal	12
Shut-In	Vertical	59
	Horizontal	15
Abandoned	Vertical	8
	Horizontal	0
Total wells	Vertical	108
	Horizontal	128
Grand total wells		236

Meta has scheduled an additional 536 wells to completely develop the field during the next six years. RPS has classified the wells as proved, probable and possible drilling opportunities. Meta has also scheduled 151 locations to which RPS has assigned resource volumes.

4.0 GEOSCIENCE

Geological Model for Entrapment

The geological model for the Rubiales field (proposed by RPS Scotia in 2007) was a hydrodynamic trap, with oil trapped by basin ward (northwestward) flowing formation waters trapping oil under a broad subtle structural nose at the top of the fluvial/alluvial Arenas Basales Formation. This trapping model is supported by a tilted oil water contact, pressure data in the reservoir section, log facies characteristics of available wells, and regional geologic information. The mapping method used to define prospective areas, using this geologic model, was the Trend Residual mapping method where subtle structural highs are identified as positive anomalies with a positive residual value when compared to the regional structural trend.

The geological tops for 29 new well logs that were provided to RPS during 2009 continue to support a tilted oil water contact. The oil-water contact and whether or not an area would be oil bearing for a well drilled within the current producing field area can be predicted using the hydrodynamic/tilted oil water contact model. Water productive wells are still located on structural anomalies. However, the RPS hydrodynamic model is not predictive of oil production extending outside the current producing area, given the current data available. The limits of the field do not appear to have been defined and appear to lie outside the concession area. Without more regionally extensive dry hole data delineating non-productive areas, a Trend Residual mapping method is not useful to predict a Rubiales field productive extension. A brief mapping exercise suggests that it is probable that more complex stratigraphic and hydrodynamic trapping elements are involved in defining the geological limits of Rubiales oil production.

Geological Work Performed

New well locations and new well logs (LAS files) for the 29 vertical wells drilled during 2009 were loaded into an existing Petra project file. Geological tops from Metapetroleum were also loaded to the Petra Project file. Thirty seven additional horizontal wells have been drilled in 2009, but LAS files and directional survey data on these wells were not made available to RPS.

The new producing wells and wet wells were inserted into the existing cross sections, and additional cross sections were constructed, incorporating the new vertical wells. (Tops were not used on RB 159 and RB 42H wells as directional survey data were not available.) RPS has over a 90% agreement with the observed Meta geological tops. Any top discrepancies were generally less than 10 feet of difference. Additional geological tops were picked for new wells. These tops were incorporated into the cross sections and the geological maps.

Based on the new well data and new tops, several of the existing maps, such as the Structure Top Arenas Basales, Structure Oil Water Contact Arenas Basales, Gross Arenas Basales Interval, Net to Gross Sand Ratio Arenas Basales Reservoir Interval, Gross Isopach Pay Interval, and Net Pay Isopach were updated and re-contoured in the Petra Project.

The Structure Top Arenas Basales map (Figure 4.1) shows monotonous northwest dip into the basin. Almost all of the new wells drilled in 2009 in the Rubiales field fit the tilted water table and hydrodynamic entrapment model as shown on Figure 4.2, the Structure Oil-Water Contact. The cross section in Figure 4.3 documents this fit and demonstrates the tilted oil water contact. Water productive wells are located on structural anomalies as noted by the contours near the blue highlighted water wells in Figures 4.1 and 4.2.

The Arenas Basales Gross Reservoir Isopach map shows a northwest trending thick interval (Figure 4.4) while the Net/Gross sand ratio map of this same interval shows the northwest trending reservoir thickening is actually higher in shale content (Figure 4.5). The Net Pay Isopach map shows an east-west trending pay interval which cuts across the northwest trending gross reservoir thickening (Figure 4.6). More work would be necessary to define the potentially more complex stratigraphic trap elements apparent from this observation.

The limits of the Rubiales field have yet to be defined. The current in-field drilling program still fits the tilted water table and the hydrodynamic trap models. However, the RPS hydrodynamic model is not predictive of the presence of oil that is known to extend outside the concession boundaries in areas that remain sparsely drilled or not drilled at all. Without more regionally extensive dry hole data delineating non-productive areas, the Trend Residual mapping method done in previous audits (in 2007 and 2008) is not useful. It is likely that more complex stratigraphic and hydrodynamic trapping elements are involved in defining the geological limits of Rubiales oil production.

5.0 PETROPHYSICS

The petrophysical work used in this analysis includes the review of the existing static model of the Rubiales Field, the validation of the petrophysical parameters and models, and an update to the existing static model with information from 29 new wells (Figure 5.1). The objective was to provide necessary petrophysical information in terms of Clay Volume (VSH), Effective Porosity (PHIE), Water Saturation (Sw) and Oil-Water Contact (OWC) depths to be integrated into the geocellular model for the volumetric estimation of the oil initially in place (OIIP) and to support the development plan of the field. The project was developed in the RPS office in Houston with interaction with Meta specialists incorporating the new well logs and core data.

An audit of all petrophysical input parameters and models used in the petrophysical evaluation of the wells was performed using the specialized software Interactive Petrophysics version 3.5.5.0, concluding that input parameters, models used, and results obtained from the petrophysical evaluation are reasonable. The available data for the petrophysical review was considered sufficient in terms of quantity, quality and consistency. A comparison of log-derived porosity and water saturation against core-derived porosity and water saturation was also done with an excellent fit. The determination of net pay thickness from the petrophysical modeling is also considered accurate.

The OWC can be established from visual analysis of the log curves signature, corresponding to a decrease of the Deep Resistivity curve into a range of 20 to 30 Ohm-m in front of a porous sand body. The petrophysical model matches this response with 100 percent water saturation below the OWC, and low water saturation values above the OWC. The variation in depth indicates a tilted OWC associated with the hydrodynamic mechanism acting in the Llanos Basin.

6.0 STATIC GEOCELLULAR MODEL

The geocellular model of the Rubiales field that was generated by Meta during 2009 was analyzed and validated. The model was then updated using seismic data, well log correlations, stratigraphic data, facies studies and a petrophysical evaluation. Volume calculations of oil initially in place were carried out to support the reserves certification objective and also to validate the field development drilling program.

The geocellular model of the Rubiales field was constructed in three steps:

- Structural Framework - The geometry or structural framework of the model was created through the three-dimensional integration and matching of well locations and paths, geological tops, and fault surfaces.
- Grid Cells - The volume of rock contained within the structural framework was divided in zones and layers and subdivided into small boxes or grids (cells). This procedure generated more than 5,400,000 cells. In this step, the cells penetrated by wells (Cell-wells) were populated with facies information and petrophysical parameters, using averaging methods as arithmetic mean, root mean square, harmonic mean, midpoint pick, etc. The facies population of the cell-wells was carried out based on facies logs and stratigraphic-sedimentary models that were determined previously.
- Extrapolation of Properties - The values within the „cell-wells' were distributed by interpolation through all the model cells. The distribution was carried out applying deterministic and stochastic algorithms, looking for the best distribution of discrete and continuous data through each cell of the geocellular model. The final version of the geocellular model of the Rubiales field is a scaled representation of the real oilfield where the geological characteristics and fluid conditions can be studied, analyzed, quantified, simulated and predicted.

The geocellular model was generated using Petrel software. The main components of the geocellular model were the structural model, facies model and petrophysical model.

The structural model includes geological tops and fault surfaces that have a relationship with fluid control. The structural model was created using six geological tops from the top of the Arenas Basales to the top of the Paleozoic, originating five lithological zones. Each lithological zone was divided into layers. A total of 65 layers were created and divided into 50m x 50m cells to get the cellular model frame with more than 5,400,000 cells.

The facies model was created by Meta using log analysis, core descriptions and sequence stratigraphic concepts. The reservoir quality facies corresponds to isolated filled channels (CH), stacked channel deposits (S-CH) and crevasse channel deposits (C-CH). The non-reservoir facies are defined as single crevasse splay (SC) and over bank deposits (O).

The petrophysical evaluation was used in the update of the Rubiales geocellular model. Detailed analysis of the well data evaluation was performed, and then several calculations of new parameters were generated. Clay volume (VSH), effective porosity (PHIE), water saturation (Sw) and net to gross sand ratio (NTG) were up scaled and loaded in the cell-wells. These data were analyzed to determine the spatial characteristics of the data through histograms, trends and variograms. This is an important and time-consuming process, which allowed determining the best input parameters to deterministic and stochastic algorithms.

The cells penetrated by well paths (cell-wells) were populated with information derived from facies and petrophysical data using averaging methods as arithmetic mean, root mean square, harmonic mean etc. Very few cells are penetrated by wells. Previous to the stochastic spatial distribution of cell-well values thru all the cells, data analyses were applied for quality control and to characterize the cell values. In this process vertical proportionality, thickness variations, histograms, trends and vertical and horizontal variograms of the cell values were generated, analyzed and quantified. These spatial data characteristics became the input parameters used for the stochastic algorithms in the stochastic spatial distribution of data through all the cells. Hundreds of variograms were generated and analyzed in order to get the best possible strike direction and trend for each facie, petrophysical parameter, and correlation facie-petrophysical property.

Several deterministic and stochastic algorithms were tested in order to determine the best spatial distribution of discrete (facies) and continuous (porosity, water saturation, etc.) data.

Facies data and petrophysical properties were spatially distributed to each cell, using the Sequential Indicator Simulation algorithm. The petrophysical properties were conditioned to the facies results.

Finally, the geocellular model of the Rubiales field was created for a set of volumes divided into millions of cells, embedded with lithology, porosity, water saturation and facies data. Figures 6.1 through 6.4 show the final distribution of these properties in the 3D model. This is the basic data used in the oil initially in place (OIIP) volume calculation in the geocellular model. A contour map that showed contours of stock tank oil initially in place (STOIIP) was also created (Figure 6.5). The contours represented the STOIIP for a 50 meter by 50 meter cell surface area with a vertical capture of the entire net pay sand thickness for the five sand members in the cell.

The volume calculation areas were defined by polygons representing the concession boundaries. The productive and concession areas contained in the Petrel model are shown below:

	Rubiales	Piriri	Total
Productive Field Area (acres)	83,590.6	51,770.2	135,360.8
Total Concession Area (acres)	88,463.0	62,431.6	150,894.6

The results are grouped in the following table by the five zones determined by the sedimentological facies in the entire concession area.

	STOIIP - MMbbls		
	Rubiales	Piriri	Total
Zone 1	1078.7	530.1	1608.8
Zone 2	802.6	446.1	1248.7
Zone 3	1033.5	276.6	1310.1
Zone 4	69.8	9.8	79.6
Zone 5	0.5	0.00	0.5
Total	2985.1	1262.6	4247.7

These values and the derived STOIIP maps were used as a basis for much of the reservoir engineering calculations in the study to aid in the reserve certification and support the proposed field development drilling program.

7.0 RESERVES DETERMINATION

7.1 Discussion

The Rubiales field contains low gravity, highly viscous oil. The recovery mechanism in the field is primary recovery, with strong pressure support from a bottom water aquifer. In such a field, the recovery factors under traditional oil field developments using vertical wells can be expected to be relatively low, in the range of 10 percent to 20 percent of OIIP. RPS analysis indicates that the maximum recovery factor of 20.3 percent can be expected for this field. To maximize the recovery efficiency, Meta has pursued a development drilling plan that will increase the well density and incorporate a significant number of horizontal wells.

The Rubiales field crude oil has low solution gas content, as represented by the gas-oil-ratio that is estimated to be 5 scf/stb. As a result, there is insufficient produced gas to warrant gas sales. Some produced gas is used as field fuel and the balance is flared. RPS has not attributed any gas reserves to the field.

Two separate concessions hold the reserves in the Rubiales field. Each concession has a unique operating and net revenue interest, thus the reserves and economics are calculated separately for each concession and then summed to get the fieldwide figures.

7.2 Developed Reserves

Reserves estimates were made using production performance analysis, volumetric estimates and production analogues. Analysis of the change in production rates, water-oil ratio and oil cut as a function of cumulative production and time was performed to predict the ultimate recoverable volumes for the producing wells. Parameters used to specify the shut in conditions were two percent oil cut at a producing rate of 30 and 150 barrels of oil per day for vertical and horizontal wells, respectively. These minimum operational production rates are dictated by water handling capacity limitations and not due to an economic limit or flow assurance problems. An exponential decline curve shape was used for the rate forecasts, with application of hyperbolic performance where well performance supports the projection after the initial flush production. Plots of the oil rate versus cumulative production, oil cut versus cumulative production and water oil ratio versus cumulative production for the producing wells were reviewed.

Reserves for wells that were completed within the past few months that have not had sufficient production decline performance were determined by using the type well analogies that were applied to the drilling locations for the undeveloped reserves. All of the type wells are located in the field, have perforated the subject sand interval, and have sufficient performance history to be a good basis for rate projections.

As of December 2009 there were 74 wells in the shut in classification. Most of the wells have prior production history, a lesser number have been tested only and have no cumulative production. Meta has advised that 60 of these wells are scheduled to be placed on production in 2010 and 2011. These wells were forecasted and scheduled, and the reserves were included in the proved developed non-producing category. The 14 remaining shut in wells are assumed to have no potential since they were not part of the re-vitalization program.

The Rubiales field has been developed with 221 vertical and horizontal wells which have indicated typical drainage areas of 50 and 87 acres, respectively. The typical drilling program involves a centralized vertical well with five horizontal wells drilled outward from the same pad location. A well cluster of this design typically drains an area of 485 acres. The horizontal wells typically drill a distance between 500' and 1,200' feet through the reservoir. The recovery from the horizontal wells exceeds that of the vertical wells. The wells have different performance characteristics also. The vertical wells initially exhibit a lower average annual exponential decline rate, and the horizontal wells initially produce at a much higher rate with a hyperbolic decline. Table 7.1 lists all the wells that have been drilled in the field with the cumulative production, proved reserves and estimated ultimate oil recovery of each.

The cumulative field production to year end 2009 was 57.6 MM barrels of oil, and the proved reserves for the producing wells on December 31, 2009 are 94.1 MM barrels of oil. The ultimate recovery (to the end of the concession term on June 30, 2016) from all wells drilled to date is estimated to be 151.7 MM barrels of oil.

The reserves that were determined by performance analysis were checked against volumetric calculations. Table 7.2 is a volumetric calculation that was performed to determine the oil initially in place per acre-foot and a "maximum case" recovery efficiency for the field. The table indicates oil initially in place of 1,450 barrels per acre-foot using the average reservoir parameters of 26.4% porosity and 27.5% water saturation. Using a sweep efficiency of 85%, the recovery efficiency is 20.3% giving a recovery of 294 barrels per acre-foot. The 20.3% recovery is considered a theoretical maximum, recognizing that not all the zones in each well will be depleted due to mechanical and operational failures, unswept reservoir areas and bypassed oil in zones that were not perforated.

A number of the wells have been drilled but have a short production history, thus performance plots could not be used to forecast the production or to estimate the reserves for these wells. These wells were classified as “proved developed producing” and assigned reserves using the type curve method used for drilling locations (as described in the next section) based on volumetric calculations and analogy. These wells with the associated proved reserves are shown in Table 7.1 and given “well analogy” as the reserve basis.

The oil initially in place within the concession area, as calculated using the updated geocellular model, is 4,248 MM stb. The concession area includes undrilled acreage on the flanks of the structure that lies outside of the developed portion of the field. This untested area is evaluated to be oil bearing based on a depositional analysis and available geological technical data which indicates the pore volume is above the original oil water contact. The potential fieldwide oil recovery using the 20.3% recovery factor would be 861 MM stb. This volume would include the 3P reserves contained in the cash flow analysis plus oil volumes from locations that are currently captured in the “resource” category, which are volumes that lie outside the possible reserves areas, volumes from wells that have been produced but in which all zones have not been perforated, and economically recoverable volumes produced beyond the current concession license expiry date.

7.3 Undeveloped Reserves and Resources

To estimate the reserves potential of the drilling program, a statistical analysis of past production was used in combination with the Petrel static model. The net pay sand of the wells that have sufficient performance to perform decline curve analysis was plotted against the estimated ultimate recovery for both the vertical and horizontal wells. Table 7.3 shows that the 39 horizontal wells were drilled in thicker pay sections (50’ average) than the 31 vertical wells (26’ average), and that the horizontal wells have an average recovery that is higher than the vertical wells, 1,325,000 stb versus 620,000 stb, respectively.

A total of 687 locations that were included in Meta's development plan have been evaluated. The wells were reviewed separately for each concession (Rubiales with 566 and Piriri with 121) since the ownership is different for each property. The reserves determination was done in two phases:

1. Assignment of reserves category based on proximity to production, and
2. Assignment of reserves volumes based on Petrel STOIIP cell values.

Phase 1

A base map containing the existing producing wells and Meta's proposed drilling locations was used to assign the reserve classification based on proximity to production. Proved reserves were assigned to new locations in areas that are undrilled and adjacent to existing wells within the proved area of the reservoir that could reasonably be judged as continuous and being commercially productive on the basis of available geoscience and engineering data. Probable reserves were assigned to areas of the reservoirs that were adjacent to proved areas but where data control or interpretations of available data was less certain. Possible reserves were assigned to areas of the reservoirs adjacent to probable areas where data control and interpretations of available data were progressively less certain.

Areas of the reservoir where the Petrel model indicated the reservoir should be present outside of the proved, probable and possible areas were designated as areas in which Meta's proposed wells would be drilled for oil volume in the resource category. The wells needed to develop these resources were given drilling location names and volumes, but production and cash flow projections were not made.

Six hundred eighty seven locations were classified as follows:

Proved	341 locations
Probable	91 locations
Possible	104 locations
Resources	151 locations

Phase 2

Each of the proposed locations was identified on a fieldwide Petrel map that showed contours of stock tank oil initially in place (STOIIP), Figure 6.5. The contours represent the STOIIP for a 50 meter by 50 meter cell surface area with a vertical capture of the entire net pay sand thickness for the one to five sand members in the cell. Values for the contours ranged between 0 to 70,000 barrels per cell, although few wells remain to be drilled in contours over 40,000 since the thicker pay sand areas have been effectively exploited by Meta.

Wells that have produced that are either depleted or that have reserves based on performance are listed in Table 7.3. The estimated ultimate recovery and the net pay are tabulated for each well, indicating the average estimated ultimate recovery and average net pay for vertical and horizontal wells is 620,000 barrels and 26 feet of net pay, and 1,325,000 barrels and 50 feet of net pay, respectively. The scatter to the data suggests that a definitive relationship between the parameters may not be present and that the recovery from proposed locations is difficult to predict from the net pay isopach map.

A second data set is shown on Table 7.4 for the relationship between the estimated ultimate recovery and the STOIIP contour map from the Petrel model. This data is also scattered such that the plot based on STOIIP values is not a good indicator of recovery from the proposed locations. The average estimated recovery for each STOIIP cell value for a vertical and horizontal well is 14.0 and 44.5 barrels, respectively.

Despite the scatter in the data relative to Tables 7.3 and 7.4, the average relationships are reflective of the historical production data and are valid for the prediction of estimated reserves for large numbers of locations such as those within the Meta drilling program. The earlier geological discussion describes the hydrodynamic trap model with the tilted oil water contact across the field, indicating the existence of many individual reservoir lobes with lateral barriers that produce independently. Absent knowing the structure and extent of each of the lobes, determination of the drainage area for each well (thus the reserves) will be best established using the statistical methods based on past well performance as indicated.

The determination of reserves and production forecasts for each location was made from the following calculations:

1. The estimated ultimate recovery per STOIIP contour for vertical and horizontal wells having production history was determined as shown on Table 7.4 to be 14.0 and 44.5 barrels per STOIIP contour per cell unit.
2. The estimated reserves for future locations were calculated using the above recoveries multiplied by the discrete STOIIP contour from 4,000 to 60,000 where the wells are spotted to be drilled.
3. The type curves shown on Figure 7.1 were generated based on past performance (initial flowrates and decline rates) and matched to the associated reserves volumes.
4. The production type curve and reserves volume from these analogies were used for each location that was scheduled to be drilled prior to the end of the concession period.

To ensure that all wells that were scheduled meet a profitability test, calculations to determine the minimum reserves needed to drill a profitable well were performed. The average well cost and the economic parameters that impact the profit calculation were used. The reserves needed to drill and produce a vertical or horizontal well are 54,500 and 70,400 barrels, respectively. Considering the different areas that a vertical versus a horizontal well would drain assuming a thin pay sand interval, the associated Petrel STOIIP contours are approximately 5,400 and 4,400 stb OIIP per grid cell for vertical and horizontal wells (for net pay intervals of 6' and 5', respectively.

The highest recovery from a vertical well and a horizontal well having performance from the plots on Table 7.3 was 1.5 million and 3.2 million barrels, respectively. It is anticipated that none of the wells drilled in the future would produce volumes approaching these figures.

In summary, there are 536 locations having 380 MMbbls of proved, probable and possible oil reserves and 151 locations having 114 MMbbls of oil resources, with these volumes being the total volume recoverable prior to depletion based on the locations that were provided by Meta. One condition for undeveloped reserves potential to be included in this report as reserves is to have a stated intention by the operator to drill the wells. Meta has indicated their intention to drill the wells and has provided the drilling schedule for 2010, which was used as guidance to continuing the drilling program through 2015. The majority of the locations in the earlier years are proved wells, with the majority of the probable and possible locations being drilled in the later years. Meta has indicated that in the later years of the concession, locations in the resource category that have an expectation of at least 10' of net pay sand would be drilled.

7.4 Summary

Reserves to End of Concession

Table 7.5 shows the reserves and annual production forecast by concession with a field total until contract expiration on June 30, 2016. Approximately 77% of the field's 3P potential ultimate recovery, or 559 MM barrels, should be produced by that date. A summary of the reserves is shown below:

Rubiales Field Reserves at December 31, 2009 (to Expiration of Concessions)

		MMBO
Proved		
	Developed	121.2
	Undeveloped	296.0
1P Reserves		417.2
Probable	Undeveloped	46.0
2P Reserves		463.2
Possible	Undeveloped	38.0
3P Reserves		501.2

Rubiales Field Potential Ultimate Recovery (to Depletion)

	MMstb	CUM MMstb	RE(%)	CUM RE(%)
Cumulative Production @ Dec 31, 2009	57.6	57.6	1.4	1.4
Total 3P Reserves @ Jun 2016	501.2	558.8	11.8	13.2
Resource Volumes	114.1	672.9	2.7	15.8
Production from July 2016 to depletion	165.3	838.2	3.8	19.7

8.0 PRODUCTION FORECASTING

The Rubiales field was discovered in 1981; however it only produced periodically until 2002 when production was reported continuously. After Meta obtained control of the operation of the field in 2004 the production increased until it reached 100 MBOPD in 2009 (Figure 8.1). The production for the Rubiales field was forecasted from January 1, 2010 to the expiration of the concession on June 30, 2016 as shown in Table 7.5. The field has 139 producing wells in the concessions with the associated reserves volumes during the concession license period as shown in the table below. These wells comprise the proved producing case.

Rubiales Field	Producing Wells	Reserves, MMbbls
Rubiales Concession	71	54.1
Piriri Concession	68	40.0
Total Field	139	94.1

Sixty shut in wells were scheduled to be back on production between 2010 and 2011. The production from these wells during the concession period was scheduled. The volumes are classified as proved non-producing reserves as shown in the following table:

Rubiales Field	Shut in Wells	Reserves, MMbbls
Rubiales Concession	46	21.2
Piriri Concession	14	5.9
Total Field	60	27.1

The Rubiales field has 536 locations in the drilling program that is forecasted to continue into 2015. The locations are expected to generate 380 MM barrels of oil before the end of the concession period. The table below shows the reserves volume split between the proved, probable and possible categories as well as the number of locations in each.

	Proved Undeveloped Locations		Probable Undeveloped Locations		Possible Undeveloped Locations	
Rubiales Field	Count	Production MMbbls	Count	Production MMbbls	Count	Production MMbbls
Rubiales Concession	264	224.7	75	39.9	80	28.5
Piriri Concession	77	71.3	16	6.1	24	9.5
Total Field	341	296.0	91	46.0	104	38.0

The production forecasts for each of the drilling programs are shown in the cash flow forecast evaluations to be discussed in Section 9.0 Determination of Value. Forecasts of the production performance by reserves category were created following the list of new locations and the 2010 drilling schedule provided by Meta as shown on Figure 8.2. This schedule of development has assumptions that include the number of rigs that would be contracted by year as well as the time it would take to drill and complete a typical well. The production forecasts of the field development plan were scheduled on an unrisked basis.

A total of 64 water disposal wells are planned to be drilled from 2010 through 2015 by Meta. The wells will be grouped into 11 clusters and the drilling is scheduled as shown below:

	Water Disposal Well Count						
	2010	2011	2012	2013	2014	2015	Total
Horizontal	9	10	9	9	8	4	49
Vertical	3	4	3	2	2	1	15
Total	12	14	12	11	10	5	64

9.0 DETERMINATION OF VALUE

9.1 Ownership

Time Period

The assessment of value for the Rubiales field was calculated for the production forecast from January 1, 2010 through the end of the Piriri and Rubiales concession contracts on June 30, 2016. Both of the concessions expire on the same date; reserves that remain after this date are not recoverable by Meta Petroleum. The effective date for discounting of field value in the evaluation is January 1, 2010.

Interests

Meta has different working and revenue interests in the two concessions as follows:

	Rubiales	Piriri
Working interest	40%	50%
Net Revenue interest	32%	40%

The royalty due from crude oil production that is sold from each concession is 20 percent. Natural gas production is negligible and is not metered or sold. The economic analysis includes the crude oil / naptha blend as the sales product. Royalty is paid on the crude oil but not on the naptha. Thus, the royalty in the economic model is based on a ratio of crude oil at 20 percent royalty and the naptha that has no royalty obligation. The net revenue share that was input into the model to properly reflect the ownership of pipeline volume to sales is 81.7 percent.

9.2 Determination of Volumes

Production

The Piriri and Rubiales concessions each have value in the proved producing, proved non-producing, and proved, probable and possible undeveloped categories. All volumes in this report are presented unrisked. Appendix 1 is an exhibit that is taken from the Petroleum Resources Management System (PRMS) report that was issued in 2007 by the Oil and Gas

Reserves Committee of the Society of Petroleum Engineers and was reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The PRMS report contains guidelines regarding the relative risk and uncertainty of recovery for the various reserves categories that are contained within this reserves certification report. The reserves and economics evaluations that were performed in this report followed the guidelines that were provided in this exhibit. A summary of the well count that is associated with each reserves category is as follows:

> Proved Producing – As of year-end 2009 there were 139 wells producing oil. 68 percent of the wells are expected to produce through June 2016 when the concessions expire.
>
> Proved Non-Producing – There are 60 wells with past production or tests that are scheduled to be re-completed in 2010 and 2011.
>
> Proved Undeveloped – 341 locations are in close proximity to prior production.
>
> Probable Undeveloped – 91 locations offset the proved undeveloped locations.
>
> Possible Undeveloped – 104 locations offset the probable undeveloped locations.

Table 7.5 shows the annual production forecast that is developed from the above re-completion and drilling program for the Rubiales field by concession and reserves category.

<u>Lease Fuel</u>

Some of the oil production is consumed as fuel in the field to heat the crude and enable the separation of the oil from the water to be more efficient. While the produced volumes have increased as the field is developed, the fuel volume has increased also. During 2009, fuel consumption increased from approximately 250 to 450 barrels per day. The current projection of fuel consumption in 2010 is 1,250 barrels per day, rising to 2,700 barrels per day in 2014 as shown in Figure 9.1. After 2014 when field production declines, the fuel consumption is forecasted to decline also to 2,400 barrels per day in 2016. Table 9.1 shows the forecasted annual crude volume to be consumed. Fuel volume was scheduled by allocation to the proved, probable and possible reserves categories for each concession.

Sales

The annual production volumes from 2010 through 2016 in each reserves category, by concession, were reduced by subtracting the oil consumed for lease fuel to determine the crude volume that is to be sold. The oil volumes that are trucked or pipelined to sales at Covenas for export are diluted by blending with naptha to increase the API gravity to meet pipeline and/or sales specifications. This naptha volume plus the crude sales volumes (field production less lease fuel consumption) comprise the total sales volumes. Table 9.1 shows the annual naptha purchases and the annual net sales volumes. These sales volumes are the volumes that are entered into the economic analysis. The costs of naptha purchase and transportation to the field are treated as a field operating cost. Also, from the present through December 2011 Meta forecasts the sale of 4,000 barrels per day of 12.5 degree API gravity crude to the local Columbian market via trucking without the addition of naptha.

9.3 Marketing

Oil Price

The forecasted annual price of WTI benchmark oil was provided by the RPS Strategic Planning Department in London in January 2010. The produced oil from Rubiales is 12.5 degrees API gravity, a low gravity that has downward price adjustments due to quality of 17.29 percent and 9.22 percent, for the trucked and pipelined oil, respectively. The oil value is also reduced for system losses of 3.29 percent and 5.16 percent, for the trucked and pipelined oil, respectively. These values are based on Meta's 2009 sales data. These price adjustments were applied to the RPS WTI price forecast and proportioned by the relative volumes that were forecasted to be trucked locally, trucked to Guaduas, or pipelined to Covenas. A weighted average price forecast was then calculated which is shown in Table 9.2. Trucking of the oil is scheduled to end in December 2011; afterwards all the oil will be transported through the pipeline.

Transportation

From field discovery through mid 2009, all of the production from the Rubiales field was trucked to sales. Trucking is very expensive and the excessive traffic damages the dirt roads within the field. During 2009, Meta constructed and commissioned a 235 km 24 inch pipeline to increase export capacity, increase safety and lower transportation costs for crude oil from the field.

The pipeline originates in the Rubiales Field and initially transported 65,000 barrels per day in its first phase. The pipeline goes from the field to Monterrey where it ties into existing pipeline facilities which transport oil to the Pacific coast at Covenas for the oil to be loaded onto oil tankers for export. The pipeline routes are shown on Figure 9.2. Because Meta's and Ecopetrol's field production will be sold in the pipeline together, the gross field production plus blended naptha is used to determine transported pipeline volumes. The scheduled growth of pipeline capacity, to be accomplished by adding more pumping horsepower as the field volume requires, is as follows:

Added Pumping Capacity Completion	Barrels per day
February 2010	120,000
March 2010	160,000
June 2010	170,000
March 2011	300,000

9.4 Costs

The investment program to develop the Rubiales field reserves with the associated infrastructure was created in 2007 when the field potential was established. Subsequent drilling and construction to this date has generally followed the original plan and resulted in a substantial investment and increase in production during the past two years. The forecasted expenditures appear to be sufficient to optimize field recovery prior to the expiration of the concessions on June 30, 2016.

The field development has included drilling producing and water disposal wells, re-completing shut in wells, building facilities to process produced fluids and to dispose of produced water, an extensive system of flowlines and water disposal lines, and the construction of tankage and lines for the purchase, handling and blending of naptha which is necessary to increase the oil gravity to pipeline specifications.

Investments - Drilling

A typical producing well program consists of one vertical well in a centralized pad location with up to five horizontal wells drilled outward from the same pad area. Costs for the location preparation, generators and pipelines are included in the well costs. The drilling well costs were provided by Meta as follows:

Well Type	Cost per well
Production well – horizontal	$1,754,000
Production well – vertical	$1,657,000
Disposal well – horizontal	$1,573,000
Disposal well – vertical	$1,296,000

These costs have been reviewed by RPS, including comparison with Meta's historical drilling cost in the field, and deemed to be reasonable.

The timing of the producing well drilling program was scheduled by Meta for 2010 and by RPS for 2011 and beyond based on the reserves analysis. The costs were assigned by the location of each well to its concession and reserves category. The schedule for drilling the disposal wells (timing and well type) was provided by Meta. Disposal well costs were distributed to each concession and split by the proportional reserves volume in each reserves category. No disposal well cost was distributed to the proved producing reserves cases because these volumes already have water disposal capacity.

The drilling program is scheduled to continue uninterrupted into 2015. An analysis of the horizontal and vertical producing wells indicates that for a horizontal and vertical well to be profitable, 70,400 and 54,500 barrels of oil, respectively, must be recovered. At the expected producing rates, the wells would payout in six months or less, making it attractive to continue the drilling program through 2015.

The cost for a well re-completion was provided by Meta to be $250,000. A review of the shut in wells across the field by Meta personnel resulted in a list of 60 re-work opportunities that were reviewed by RPS. An analysis of the past performance of these wells indicates the potential to re-establish production. The re-completions are scheduled to be completed in 2010 and 2011.

Meta had signed contracts for five drilling rigs in 2008 that kept the rates constant for a three year period through 2011. Thus, no cost inflation was applied to the well costs until 2012 when a two percent annual inflation was applied. Meta uses just two types of rigs in the field. By limiting the rig types to two, operating and maintenance costs are kept as low as possible. The re-completion well work will be done using smaller rigs that have a two percent cost inflation beginning in 2010.

The forecasted annual drilling and re-completion investments are shown on Table 9.3.

Investments - Facility

The work to expand the capacity of the field infrastructure continues concurrently with the drilling program. The metering and processing facilities, water injection pumps and lines, and naptha blending tanks and equipment to accommodate the increasing production are under construction. New areas, as developed, will also benefit from infrastructure projects to process higher volumes of produced fluids. These facility investments were scheduled by Meta and are shown on Table 9.3. The costs were allocated to each concession and reserves category based on the percentage of reserves to be recovered. The escalation rate applied to these costs was two percent.

The costs to manage the rising water production are substantial and projected to increase into the future. An additional 500,000 bwpd of capacity is scheduled for installation in 2010. At the various water injection sites, clusters of horizontal injection wells are drilled around a single vertical injection well, and pump capacity is designed based on the expected water production in the area. If additional capacity is required due to higher than planned water production, more pumping capacity is installed rather than the drilling of additional wells. Wells are planned to dispose of 45,000 bwpd, but are capable of disposing of up to 70,000 bwpd. Produced water is fresh with essentially no contaminants, and the continued disposal of 300,000 bwpd into the nearby river is expected.

Expenses - Operating Costs

The operating cost history for the past several years for the Rubiales field has been provided by Meta. The cost schedules have been reviewed by RPS, compared with historical costs and deemed to be reasonable.

The monthly costs in 2009 from January through October steadily increased as produced volume increased from 1.5 to 2.5 million barrels per month. In October, the operating cost was $9.3 million, or $3.64 per barrel. The trend line shows the costs were on track to reach $3.75 per barrel by year end 2009. An average operating cost of $4.00 per barrel was estimated for 2010. The forecast generated by RPS for this analysis indicated an average 2010 production volume of 151,500 barrels of oil per day. As a result, the total operating cost that is forecast for 2010 is $221,192,000 which is substantially above the costs in the prior years.

The cost noted above was split at a 35% / 65% ratio between fixed and variable cost components, respectively. The fixed cost of $77,417,000 that is shown on Table 9.4 represents the annual operating cost that is independent of the well count or the production volume. To reflect the growth in field facilities, the fixed cost was increased by five percent in 2011 and 2012, followed by no increase in 2013. The variable cost of $143,775,000 represents operating costs that will vary with well count and production volume. The variable cost was split at a 35% / 65% ratio between well count and production volume. Variable costs of $286,000 per well (based on the average 2010 forecasted well count) and $1.69 per barrel (based on the estimated cost allocated to the forecasted 2010 production) were determined. All operating costs were escalated at an annual rate of two percent.

In previous year analyses, a road maintenance cost of $0.79 per barrel was added to the production expense due to the excessive road usage by the oil trucks prior to the construction of the export pipeline. The road use by the trucks hauling oil has declined considerably now since the pipeline is in operation, resulting in a less costly road repair program. Meta advised that the cost of road maintenance is now handled by the army that is stationed in the field.

An additional variable cost that is charged is Meta's overhead and administration. Meta advised that this cost is $0.50 per barrel; it was added to the variable cost of $1.69 to determine the total variable cost of $2.19 per barrel of produced oil.

<u>Expenses – Naptha Purchase</u>

The produced crude oil has 12.5 degree API gravity, and due to its high viscosity it does not meet pipeline specifications. Naptha at 82 degree API gravity is trucked to the field and blended with the crude oil to lower the viscosity. The blended oil has 18.5 degree API gravity, meets pipeline specifications and sells for a higher price than the unblended produced crude oil. The oil that is transported by trucks and sold locally is heated in the trucks to reduce its viscosity and is not blended with naptha.

The required naptha volume is a function of the relative crude oil quality and produced volume from the Rubiales, Caracara, Ocelote and Quifa fields. The crude oil from these fields is blended in the pipeline, and the final mixture must be of pipeline quality. The forecasted production, naptha requirements and pro-rated volume of naptha that is blended with Rubiales crude have been determined by Meta and furnished to RPS for this analysis. The naptha is purchased for the posted price of WTI oil less $5.00. The forecast of naptha prices, annual volume requirement and annual expenditures to purchase the naptha are shown on Table 9.4.

Expenses – Tariffs and Blending

Until the pipeline in the field reaches its maximum capacity of 300,000 barrels per day in 2011 with additional pump installations, some crude oil will be trucked from the field to the Guaduas Station. At Guaduas, the crude is blended with naptha to reach a API gravity of 18.5 degrees prior to entering another pipeline to Covenas. The tariff to deliver the 82 degree API gravity naptha from the Cartagena sea port to Guaduas is $11.55 per barrel, and an additional $0.33 per barrel is charged for the blending process. The crude oil that enters the field pipeline to Covenas for export is blended with naptha in the Rubiales field to reach the API gravity of 18.5 degrees. The delivery charge for the naptha from the Cartagena sea port to the field is $9.80 per barrel, and there is no blending charge there. The naptha tariff and blending costs are summarized in Table 9.4.

The crude oil and blended oil/naptha mix incur tariff charges also. Meta is charged $10.73 per barrel for crude that is trucked to Guaduas. After blending there, the oil/naptha mix is pumped into a pipeline that charges a tariff of $2.03 per barrel to deliver the mix to Covenas for export. The blended oil/naptha mix that leaves the Rubiales field in the new pipeline directly to Covenas for export is charged a tariff that is coupled with throughput volume as follows:

Daily Volume from Rubiales Field	Tariff Charge
100,000 to 125,000 bbl per day	$6.39 per barrel
125,000 to 150,000 bbl per day	$5.57 per barrel
150,000 to 175,000 bbl per day	$6.55 per barrel
Over 175,000 bbl per day	$6.30 per barrel

The crude oil and oil/naptha mix tariffs and blending costs are summarized in Table 9.4. The average unescalated cost for tariffs and blending of produced crude oil and purchased naptha is $8.07 per barrel over the life of the project.

Although the cost per barrel to truck the crude from the field is expected to decrease as the pipeline capacity increases from 2010 to 2011 when the trucking is ended, the decline in cost was not modeled in the economics as it is not significant relative to the overall analysis results.

Expenses - Abandonment and Reclamation

Production forecasts indicate that the majority of the wells would produce to at least June 30, 2016. The concession contracts do not require that Meta abandon inactive wells unless the wells have been junked for mechanical reasons. Based on past experience, Meta has forecasted that 2.5 percent of the wells in the field would need to be abandoned on an annual basis at a cost of $300,000 each. The annual cost for this work has been included in the RPS forecasts of field operating cost and is shown in Table 9.4.

9.5 Evaluation Parameters

The revenue and costs were input by concession so that the appropriate working and net revenue interest cash flows could be calculated separately. The analysis was made for both before tax and after tax cases. A two percent escalation was applied to the investment and operating costs based on actual Columbian data and the global RPS oilfield forecast.

A 33 percent income tax was used in the after tax analysis. A tax credit for investments was also used in which 40 percent of the total net investment for 2009 was deducted in 2010, and 30 percent of the total net investment in 2010 and 2011 was deducted in 2011 and 2012, respectively. The tax credit was allocated by concession and reserves volume by category. No tax credit was assigned to the proved producing reserves in 2011 and 2012 because those volumes that were developed in prior years did not require future investments to produce to depletion.

The annual cash flow profit was then discounted to present worth using a 10 percent discount rate, and summed to calculate the cumulative discounted cash flow by concession and reserves category. All dollars mentioned in the report are in U. S. currency.

9.6 Analysis Results

The PHDWIN economic model was used to perform the economic calculations. Tables 1.1 through 1.8 contain the summary level results. Output from these runs is included by concession for each reserves category in Appendix 2 (before tax cash flows) and Appendix 3 (after tax cash flows).

Note: Due to the inclusion of naptha diluent in the sales volumes, and "hardwired" program output formats of the PHDWIN software, the summary outputs and column labels do not match other reporting tables in this report. The following glossary should be used in interpreting the PHDWIN cash flow output tables:

"PHDWIN Column Label" = Meaning for this report

"Gross Oil" = Total field oil production (ie gross field reserves) plus Naptha diluent less oil shrinkage

"Net Oil" = Meta Working Interest share of Net Reserves = Meta share of [total oil reserves plus Naptha diluent less oil shrinkage less Royalty]

"Oil Revenue" = Meta Working Interest Net (after royalty) revenue

" Well Count" = Number of PHDWIN cases included in analysis

"Net Investment" (on the before tax report) = Meta Working Interest share of Development Costs

"Net Investment" (on the after tax report) = Meta Working Interest share of Development Costs minus Capital investment tax credits

"Net Lease Costs" (on the before tax report) and "Net Op Costs" (on the after tax report) = Meta Working Interest share of Operating Costs (including annual abandonment costs)

"Federal Income Tax" = Meta Working Interest Federal Income tax before application of Capital Investment tax credits

Appendix 2 contains the detailed annual revenue, cost, net and discounted cash flow figures for the before tax evaluation cases described as follows:

Page 1	Grand Total
Page 2	Proved Producing Total
Page 3	Piriri Concession – Proved Producing
Page 4	Rubiales Concession – Proved Producing
Page 5	Proved Non-Producing Total
Page 6	Piriri Concession – Proved Non-Producing
Page 7	Rubiales Concession – Proved Non-Producing
Page 8	Proved Undeveloped Total
Page 9	Piriri Concession – Proved Undeveloped
Page 10	Rubiales Concession – Proved Undeveloped
Page 11	Probable Undeveloped Total
Page 12	Piriri Concession – Probable Undeveloped
Page 13	Rubiales Concession – Probable Undeveloped
Page 14	Possible Undeveloped Total
Page 15	Piriri Concession – Possible Undeveloped
Page 16	Rubiales Concession – Possible Undeveloped

Appendix 3 contains the detailed annual revenue, cost, net and discounted cash flow figures for the after tax evaluation cases described as follows:

Page 1	Grand Total
Page 2	Proved Producing Total
Page 3	Piriri Concession – Proved Producing
Page 4	Rubiales Concession – Proved Producing
Page 5	Proved Non-Producing Total
Page 6	Piriri Concession – Proved Non-Producing
Page 7	Rubiales Concession – Proved Non-Producing
Page 8	Proved Undeveloped Total
Page 9	Piriri Concession – Proved Undeveloped
Page 10	Rubiales Concession – Proved Undeveloped
Page 11	Probable Undeveloped Total
Page 12	Piriri Concession – Probable Undeveloped
Page 13	Rubiales Concession – Probable Undeveloped
Page 14	Possible Undeveloped Total
Page 15	Piriri Concession – Possible Undeveloped
Page 16	Rubiales Concession – Possible Undeveloped

10.0 QUALIFICATIONS AND LIMITATIONS

10.1 Independence and Conflict of Interest

This report has been prepared by RPS. RPS is an international independent oil and gas advisory firm with Energy Division offices in the USA, UK, Canada, Singapore, Australia and the Netherlands. This report was prepared in the RPS office located in Houston, Texas. All evaluations performed by RPS are strictly fee-based and RPS has not and will not receive any benefit, which may be regarded as affecting its ability to render an unbiased opinion.

10.2 Purpose, Scope and Use of This Report

This report was commissioned by Mr. Ysidro Araujo of Meta to evaluate the Rubiales Field. The scope of the project was restricted to this brief. This report was prepared exclusively for the use of the stated parties and should not be duplicated or distributed to any third parties without the express written consent of RPS, except as required by law.

10.3 Available Data

This study was based on data supplied by Meta and on nonproprietary data from in-house files. The supplied data was reviewed for reasonableness from a technical perspective. As is common in oil field situations, basic physical measurements taken over time cannot be verified independently in retrospect. As such, beyond the application of normal professional judgment, such data must be accepted as representative. While we are not aware of any falsification of records or data pertinent to the results of this study, RPS does not warrant the accuracy of the data and accepts no liability for any losses from actions based upon reliance on data, which is subsequently shown to be falsified or erroneous.

10.4 Professional Qualifications

RPS personnel who prepared this report are degreed professionals with the appropriate qualifications and experience to complete the project brief. RPS and its staff do not claim expertise in accounting, legal and environmental matters, and opinions on such matters do not form part of this report.

10.5 Site Visit and Inspection

A site visit to the Rubiales field and Meta's technical office in Bogota was conducted by three RPS personnel directly involved in the preparation of the report on December 14 and 15, 2009. The ongoing development activity was observed, including drilling operations, production facilities, water disposal facilities, and numerous construction projects that are in progress. Pipelines, in-field gathering lines and the road system and living areas for staff and construction crews were also observed. Every day, a personnel contingent of 5,800 people works in the field. This requires a major coordination effort for personnel and materials that are brought in for the field operations and construction projects. The work is conducted in a manner that respects the native population as well as the environmental concerns of the government. RPS is not in a position to comment on whether the operations are in compliance with any regulations that may apply to them.

10.6 Liability Waiver

This report has been prepared on a best efforts basis to address the requirement of the brief specified by the clients. The results and conclusions represent informed professional judgments based on the data available and time frame allowed to perform this work. No warranty is implied or expressed that actual results will conform to these estimates. RPS accepts no liability for actions or losses derived from reliance on this report or the data on which it was based.