EFFICIENCY OF BOLIVIAN HYDROCARBON RESOURCE DEVELOPMENT: CASE STUDY OF A MEGA-FIELD IN THE CONTEXT OF REGIONAL MARKETS AND POLICY FRAMEWORK INCENTIVES

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Ministry of Education of Bolivia

Thesis Dissertation
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Bolivia is a natural gas producer and exporter (60MMm3/d in 2015)
About 80% goes to Argentina and Brazil
20-year long contracts (Brazil, 1999; Argentina, 2006), Prices indexed to oil, ToP and DoP Clauses
Contracts expiring in 2019 (Brazil) and 2027 (Argentina)
Revenues from natural gas sales account for 50% of Bolivian total exports in 2015
Motivation

- Provide a quantitative example of current challenges in the hydrocarbon sector for the Bolivian government
  - Supply and demand gas looming
  - Reserves declining
  - Limited exploration investments
  - Competition in export markets
- Evaluate effectiveness of incentives and fiscal regime
- Support justification of policy with numbers (reference to political opposition and general public)

Incentives

- Production coming from few fields and production gap
- Reserves decreasing, investments efforts not enough
- Competition: LNG, Unconventionals, Offshore
Thesis Objectives

• Production forecasting of a representative mega-field
• Quantify the impact of the hydrocarbon fiscal regime change on historic NPV distribution
• Determine the future proportion of the NPV for the government and the contractor under different price scenarios
• Determine if the 2015 Incentives Law encourages drilling activities in existing fields
Agenda

1) Production Forecasting
2) Pricing Scenarios & Regional Natural Gas Markets
3) Fiscal Systems Impact
4) Results
1. Production History and Forecast
San Alberto Field

• Quick facts
  – OGIP= 5.2 Tcf (gas only)
  – First production: January 2001
  – Naturally fractured gas-condensate reservoir

• Geological setting
  – Located in the Southern Sub-Andean Zone in the Chaco Basin
  – Zone characterized by north trending narrow anticlines.
  – Steep structures with dips close to 90 degrees
  – Producing formations of the Early Devonian: Huamampampa, Santa Rosa and Icla
Why San Alberto?

• The project has lived through two fiscal systems
• It has a considerable NGL production, subject to incentives
• Representative of the 3 mega-fields that account for 70% of natural gas and condensate production (similar contracts, history, properties)
Production History

• Production started in January 2001
• Plateau: 400 MMscfd
• 9 wells drilled, 3 wells were planned to be drilled in 2015-2019
Production Forecast

• Decline Curve Analysis
  – Least square method with Arps equations

\[
q = q_i \times (1 + b \times D_i \times t)^{-\frac{1}{b}}
\]

\[
N_P = \frac{q_i^b}{(1 - b) \times D_i} \times q_i^{1-b} - q^{1-b}
\]

\[
\min \sum (N_{p,\text{calculated}} - N_{p,\text{historic}})^2
\]

• Results DCA per well-basis
  – Not satisfactory: Di close to 0, b greater than 5
  – 2 wells in early life
  – Almost no decline in others
  – Change in operating conditions to maintain flow rate
Production Forecast

- Steep decline starts in 2014
- DCA performed for the aggregated field production for the months corresponding to the declining period
Production Forecast

- Regression fits reasonably the flow rates and cumulative production

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Natural Gas</th>
<th>Condensate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qi</td>
<td>428,952</td>
<td>7,024</td>
</tr>
<tr>
<td>Di</td>
<td>0.279</td>
<td>0.346</td>
</tr>
<tr>
<td>b</td>
<td>0.676</td>
<td>0.654</td>
</tr>
</tbody>
</table>
Production Forecast

• DCA for the field production

• Cumulative production corresponds to a RF= 42% (gas only)
2. Natural gas pricing, regional markets and demand scenarios
Natural Gas Pricing

- Prices in the domestic market are fixed and subsidized ($1.1/MMBTU)
- Indexed to a basket of Fuel Oils
- They can be correlated to the WTI oil price
- The real sale price is the weighted average of the prices to the domestic and foreign markets
- In order to obtain it, we need to know the volumes directed to each market.
Historic Price Correlations: Export Markets

- Oil indexed Price (basket of fuel Oils)
  \[ P_{G,Br} = P_i \times (0.5 \times FO_1 + 0.25FO_2 + 0.25 \times FO_3) \]
- They can be correlated with a linear regression

[Graphs showing correlations between gas prices and oil prices for Argentina and Brazil with regression lines and correlation coefficients]
Forward Price Scenarios: 2016-2029

• Price scenarios ($/bbl): 40, 60, 80, 100, 120 in 2020.

• Prices for natural gas to Brazil and Argentina calculated with correlations.
Regional Markets: Argentina

Domestic: Unconventional
- 801.5 TCF of technically recoverable shale gas
- Gas Plan: Incentives of $7.5 /MMBTU
- $16 billion investment to reach for self-sufficiency

Imports Bolivia
- 20 year contract, it ends in 2027
- Scaling volumes: 27.7 MMm3/d in 2021
- Take or Pay clauses

LNG Imports
- 2 regasification plants: Bahia Blanca and Escobar
- 14.1 MM/m3d regasification capacity
- Seasonal: In winter for residential consumption
Regional markets: Brazil

**Domestic: Offshore**
- Growing gas domestic production
- Technical challenges: ultra-deep, high CO2
- Liberalization of the market

**Imports Bolivia**
- Duration: 20 year contract, it ends in 2019
- Quantity: 30.5MM/m3d
- Take or Pay clauses

**LNG Imports**
- 3 regasification plants and 1 in construction
- 41 MM/m3d regasification capacity + 19.5 MMm3/d
- Seasonal
Demand Scenarios and Weighted Average Pricing

• Low Demand Scenario
  – Take or Pay Quantities for Brazil and Argentina
  – Renewal with Brazil for half of the quantity of current contract
  – 7% increase in Bolivian market

• High Demand Scenario
  – Maximum Quantities for Brazil and Argentina
  – 7% increase in Bolivian market + Petrochemicals
3. Fiscal Systems Impact
Workflow

Fiscal conditions

Input
- Royalties & Taxes
- Contracts
- Hydrocarbon Production
- CAPEX & OPEX, Depreciation
- Transport and Abandonment Costs

Output
- Rate of Return
- Net Present Value
- Contractor and Government Take

ECONOMIC MODEL

Market conditions
- Hydrocarbon Price
Legislation changes

– Production revenue split of the San Alberto field has been subject to three different fiscal regimes

1. 1996-2007
   - Concessionary system
   - 18% Royalties
   - Indirect taxes: (On profits, transactions, remittances, surtax, VAT)

2. 2007-Present
   - PSC/Service contract
   - 50% Royalties
   - Indirect Taxes (Elimination of surtax)
   - Allows Cost Recovery
   - Introduces YPFB Share f(B, q)

3. 2015
   - Flexibility of norms and regulations
   - Law of incentives
   - 0 to 30$/bbl incentive for additional condensate production
1. Concessionary system
2001-2006

- Value added tax (VAT)
- Transaction tax (IT)
- Corporate profit tax (IUE)
- Remittance tax (IRUE)
- Surtax
2. PSC/Service contract 2007 onwards

Cost recovery limit: 60% of net revenues
3. Incentives

Incentives Fund → Contractor

- **Incentives for condensate production**

Contractor → YPFB

- **12%**

YPFB → Government

1. Gross Revenue (GR)
2. Royalties
3. Royalties
4. National Tax on Hydrocarbons (IDH)
5. National Tax on Hydrocarbons (IDH)
6. a. Profit Share: Contractor
6. b. Profit YPFB Participation
7. Indirect Taxes
8. Indirect Taxes - YPFB
9. Net Cash Flow ($us)
10. Expected Monetary Value
4. RESULTS
Fiscal regime impact: past NPV split (2001-2016)

- Growth of the government take from 56% to 88%
- Royalties are the major source of income, followed by the corporate tax (IUE) in 2001-2006, and the YPFB Share in 2007-2016. Minor role of taxes that depend on the contractor’s profit.
Forward economics under different price scenarios (2016-2029)

- The government take is around 90% for all price scenarios; except for $40/bbl price scenario with 96%
- NPV grows as price does ($900 million-$1,200 million)
- Contractor IRR hardly varies (17.8%-18.1%)
Historic, low revenues with high contractor take followed by a low contractor take percentage but cash flow balanced by higher revenues.

Period 2015-2016, steep drop in revenues.

Period 2017-2029, low production, extra revenue of price increase absorbed by YPFB Participation. Lowest price scenario results in months in the red for the contractor.
YPFB Share impact on Contractor Take

- As cost recovery index (B) increases and production decreases, YPFB share increases.
- Contractor take is limited by YPFB share.
Feasibility of future drilling activities

- 3 wells planned in 2015-2019, decision to drill the first well studied
- 1st month of production assumed in January 2017
- Initial rate of production 30 MMscfd
- Step 1) Evaluate Impact of incentives
- Step 2) Evaluate EMV based on probability of success for development wells

\[ I_t = (-0.6398 \times WTI_t + 47.345) \times Q_t \]

\[ 27.11 < WTI_t < 74 \]

\[ 30 > I_t > 0 \]
Step 1: Impact of the incentives (2017-2026)

- Government: the extra revenue exceeds the incentives fund and the incentives to the company
- The incentives disbursed to the company don’t exceed the incentives fund

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<tr>
<th>Price Scenario</th>
<th>Available Incentives Fund: 12% of National tax on Hydrocarbons since 2016</th>
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</thead>
<tbody>
<tr>
<td>$40/bbl</td>
<td>$64,679,470</td>
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<tr>
<td>$60/bbl</td>
<td>$90,590,779</td>
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<table>
<thead>
<tr>
<th>Price Scenario</th>
<th>Incentives to Company</th>
<th>Government Extra Revenue</th>
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</thead>
<tbody>
<tr>
<td>$40/bbl</td>
<td>$22,458,531</td>
<td>$181,343,910</td>
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<tr>
<td>$60/bbl</td>
<td>$11,396,235</td>
<td>$282,717,043</td>
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</table>
Step 2: Impact of incentives on EMV (2017-2026)

- The EMV is plotted against probability of dry hole.
- For wells costs, the $40/bbl price scenario EMV is negative without incentives and positive after incentives.
- The $60/bbl price scenario EMV is positive for both well costs.
- The incentives are effective for this assumed probability of failure.
Historic probability of success of development wells: 82%
Conclusions

• First period (2001-2006) of a fairly equal share (56-44) with a bigger share of taxes on profits.
• Second period (2007 onward), new fiscal regime designed to maximize the government take (88%), especially in the mega-fields (YPFB share tables and 60% cost recovery limit). Still profitable for the company due to high commodity prices and production peak.
• Third period: Lower future revenues due to decline of production, lower commodity prices. Unattractive to operate during the mature phase due to a growing government take through YPFB share (especially unattractive in a low price environment, months in the red for the $40/bbl price). Variable share inefficient in low price scenarios.
• The incentives encourage drilling decision under all considered price scenarios by providing a positive EMV for the contractor for the historic probability of success. If drilled, additional production from the mega-fields provide time for exploration and development activities of new fields.
Thank you for your attention. Any questions?