Local content in Brazilian oil and gas auction*

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Abstract

In this paper, we study the case of Brazilian oil and gas auctions to assess the impact of local content requirements in bidding behavior, allowing us to estimate its impact on government revenue. The Brazilian case is particularly appealing, as there were significant changes in these requirements throughout the years. In the sales with increased local content requirements there was a dramatic change in the bidders behavior: the average signing bonus for offshore tracts dropped from an average of R$ 57 million in the first sales to only R$ 10.6 million and the average number of bids per tract plunged from 0.92 to 0.12. We aim to answer how much the increased local content requirements affected participation and revenue in the auctions. We develop and estimate a structural auction model within the mineral rights framework that includes an entry decision and bids in multiple dimensions, including a bonus and a local content percentage. Our results show that local content requirements increase costs in deep water areas in 14%. Government revenue in auctions in these areas could be much larger in a counterfactual with no local content requirements, amounting to an extra R$ 17 billion in signing bonus only for deep-water tracts. For onshore areas, we did not find any significant difference between local and foreign costs.

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1 Introduction

The discovery of large deposits of oil and gas is usually followed by policies designed to maximize their benefits to the economy of the country where they are located. One of the mechanisms used to achieve this goal is the stipulation of local content requirements, which aim to foster demand for local goods and services[1].

In this paper, we study the case of Brazilian oil and gas auctions to assess the impact of these requirements in bidding behavior, allowing us to estimate its impact on government revenue. The introduction of minimum requirements for local content should have a straightforward effect in the auctions: an increase in production costs would lower estimated profits, reducing participation and revenue. Nonetheless, the magnitude of the effect is critical in evaluating the policy.

The Brazilian case is particularly appealing to study this issue, as it featured a scoring rule comprising a local content dimension with significant changes in its relative weight throughout the years. In the first auctions held, from 1999 to 2002, local content accounted for only 15% of each firm's score, increasing to 40% in 2003 and 2004, when the government backtracked and reduced it to 20% for all sales until 2016. Particularly, these shifts should impact badly in auctions for offshore tracts, where the exploration and drilling costs are much higher than on land. Also, the bigger technological requirements mean a higher cost differential between sourcing in Brazil or abroad.

In the sales with increased local content requirements there was a dramatic change in the bidders behavior. As seen in Figure 2(a), the average signing bonus for offshore tracts dropped from an average of R$ 57 million in the first sales to only R$ 10.6 million in the 5th and 6th rounds. The average number of bids per tract also plunged from 0.92 to 0.12 (Figure 2(b)). On the other hand, the local content bids expanded from 31% to 71% (Figure 2(c)).

This paper aims to answer how much does the reduction in participation and the lower revenue in the auctions can be attributed to the increase in the weight of local content. We develop and estimate a structural auction model within the mineral rights framework that includes an entry decision and bids in multiple dimensions, including a bonus and a local content percentage.

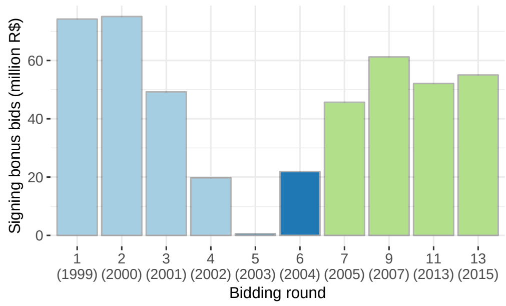
The Brazilian auctions feature a unique non-linear scoring rule for which there is no equilibrium characterization in the literature (Sant'Anna (2018)). We perform a linearization of this rule, which along with common values assumption, allow us to solve a symmetric equilibrium as in Wilson (1969, 1977). We estimate the model primitives, including the local and foreign production costs, a participation cost and the accuracy of *ex-ante* information about the tracts' true value.

Our results show that local content requirements increase costs in deep-water areas in 14%, affecting significantly the behavior of firms in the leasing auctions. We show that government revenue in auctions in these areas could be more than 200% larger in a counterfactual with no local content requirements, amounting to an extra R$ 17 billion in signing bonus only for deep-water tracts. For shallow waters, the cost difference is slightly bigger, around 16%, and the extra revenue would be R$ 67 billion, although our estimates are noisier in this location. For onshore areas, we did not find any significant difference in cost.

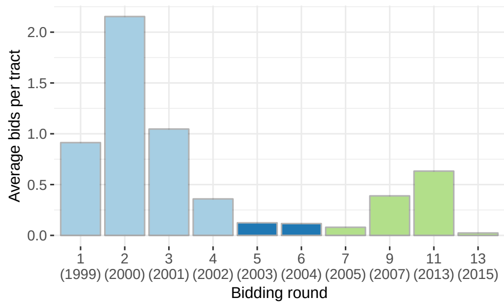
Oil an gas auctions have already been thoroughly studied, specially in the United States context. Issues such as the existence of asymmetrical information between firms (Hendricks and Porter,

[1]See Tordo et al. (2013) for a review of local content policies for the oil and gas sector across the world.

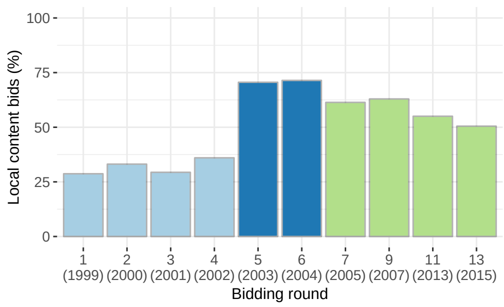
Figure 1: Average signing bonus and local content bids for offshore tracts in Brazilian oil and gas auctions



(a) Signing bonus bids



(b) Participation



(c) Local content bids

Note: all monetary values are in R$ 2017. The 8th bidding round was annulled in courts. In the 10th and 12th rounds no offshore tracts were offered.

1988; Porter, 1995); the impact of joint bidding (Hendricks and Porter, 1992); bidding with random reservation prices (Hendricks et al., 1994); timing of drilling (Hendricks and Porter, 1996); among several others. These studies use data on auctions that began in the 1950s, and it is key that they observe the production in each tract in order to reach its conclusions.

Regarding Brazilian oil and gas auctions, Perez (2010) shows the existence of the winner's curse, arguing in favor of the common-value framework for the Brazilian case. One distinguishing feature of the sector in Brazil is the presence of Petrobras, which arguably has better information due to its decades of monopoly. Brasil and Postali (2014) argue in favour of this hypothesis by estimating that Petrobras has higher informational rents, although in a setting that assumes independent private values (IPV). Matoso and Rezende (2014) further explore this hypothesis in a mineral-model rights setting, following Hendricks and Porter (1988) procedure and concluding that indeed Petrobras seems to be the most informed bidder.

The first study to explicitly consider the multidimensional aspect of oil leases in Brazil is Sant'Anna (2018). He deals with the absence of equilibrium due to the scoring formula by using the first-order conditions implied by the optimization problem, which allows him to study nonparametrically the trade-off between revenue and exploration investment, which is the third dimension of the scoring rule. However, he is forced to assume the IPV benchmark and restrict his sample to onshore tracts in mature basins, where this assumption is more realistic. One consequence is that he is unable to make any conclusions regarding the local content dimension, due to lack of variation in data for these tracts. On the other hand, our methodology, while assuming a simpler scoring rule, allows us to estimate the impact of the increase in local content requirements in a common-value context, which permit us to keep in our sample offshore areas, the most relevant for oil output in Brazil. We note that we opted to focus the paper on local content, and the minimum exploratory program dimension in our analysis is exogenous, not allowing for any comparison with Sant'Anna (2018).

Another contribution of this paper is the use of production data, which allow us to have a clearer measure of tract value and that, to our knowledge, had not yet been used in oil auctions studies in Brazil. As our sample is very recent, we use a decline curve technique to forecast future production, such as in Haile et al. (2010).

Finally, this paper is also related to the literature of scoring auctions, such as Che (1993) and Asker and Cantillon (2008). In the literature, the prevailing empirical analysis of scoring auctions is in a procurement setting, where IPV is a reasonable assumption. In this paper, we contribute with an empirical application of a scoring auction in a common-value framework.

The rest of the article is organized as follows: in chapter 2 we discuss the institutional background of the oil and gas industry in Brazil, present the data sets used and document the changes in local content policy and bidders behavior in the auctions. In chapter 3 we we present the common values structural auction model. In Chapter 4, we discuss the identification procedure and give the estimation strategy for the scoring rule and cost distribution. The results and counterfactuals are presented on Chapter 5, followed by some robustness tests. In Chapter 6 we present our final remarks.

2 Regulatory environment and data

2.1 Regulatory environment

Since the first discoveries of oil in Brazil, in the 1940s, there have been several different regimes for the sector. After a heated national debate, it was decided in 1953 to institute a monopoly of the state-owned Petrobras for exploration and production of oil, which lasted until 1997. In this year the government introduced a concession regime for the upstream oil industry, in which the National Petroleum Agency (ANP) leases tracts subject to exploratory risk through auctions, with an upfront payment by the winner. After several sales in this regime, the discovery of huge oil reservoirs prompted the government to present in 2010 a new production sharing policy aimed only at tracts around the new discoveries, with the others remaining in the concession regime. In this article, we will not consider the auctions held in the production sharing setting, as there is not enough data available and the incentives to firms is very different than in the concession regulatory environment.

In the concession regime, the winning firm wins the right to explore for oil and gas in the tract in exchange for an upfront payment, called signing bonus, retention fees for as long as it occupies the area and royalties charged on revenue[2]. Oil fields with output higher than a certain threshold also have to pay a special participation levied on profits.

The "Petroleum Law" that instituted the concession regime also created the National Energy Policy Council (CNPE), which define the main guidelines regarding the oil and gas industry and approves which tracts will be auctioned, and ANP, which performs the auctions. The auctions are organized in bidding rounds, when multiple tracts are sequentially auctioned. Once the tracts for the round are chosen, ANP releases a draft of the tender protocol and a contract model, which are subject to public hearings. Then, companies enroll in the auction, pending the payment of a small participation fee and the submission of financial and technical documentation. To these firms, ANP releases technical data about each tract, subject to non-disclosure agreements.

Next, there is the public session in which the companies, individually or in a consortium, submit a multi-dimension sealed bid for the tract of interest. The bid must contain a signing bonus, in R$, which must be above the reserve price set for the tract, and, depending on the round, a minimum exploratory program (MEP), in units, and a percentage of local content (LC) for investments in the exploratory and development phases. The tender protocol in each round contains a table with the conversion between seismic tests and well drilling to MEP units.

Each consortium must include a unique operator, that is, the firm responsible for the exploration of the tract, while the others participate only financially. Until the 4th Round, tracts were auctioned sequentially, while from the 5th round onwards they were organized in sectors, and all tracts in a given sector were auctioned simultaneously.

Auction rules depend crucially on the tract location, usually divided in onshore, shallow waters (water depth under 400m) and deep waters (over 400m). The evolution in the auction bidding criteria is in Table 1. The first major change happened in the fifth round, when there was a big decrease in the weight of the signing bonus, from 85% to 30%, and a raise of 15% to 40% on the percentage of local content and the introduction of a minimum exploratory program criteria,

[2]Royalties are usually fixed in 10%, but may be lowered to 5%, depending on tract characteristics and pending government approval. In our sample, the vast majority of the fields are subject to the 10% rate.

corresponding to 30% of the bid evaluation. To this shift was added an expansion of the minimum requirements for local content, shown in Table 2, which probably had a relevant impact on the auctions in the 5th and 6th round. There were minor shifts in the scoring weights after the 7th round(2005), with the most substantial revision being a narrowing of the band of the local content bids, which reduced the scope for competition in this dimension.

Table 1: Evolution of bids evaluation criteria in Brazilian oil and gas auctions

	Weights			Minimum Requeriments	
Rounds	Bonus	MEP	LC (Exp + Dev)	MEP	LC
1 - 4	0.85	0	0.03 + 0.12	Yes	No
5 - 6	0.3	0.3	0.15 + 0.25	No	Yes
7 - 13	0.4	0.4	0.05 + 0.15	Yes[1]	Yes

[1]Except on 7th and 9th rounds.

Table 2: Minimum and maximum requirements for local content in the exploration and development phases in Brazilian oil and gas auctions

Rounds	Location	Exploration *Min*	Exploration *Max*	Development *Min*	Development *Max*
1 - 4	All	0	0.5	0	0.7
5 - 6	Deep Waters	0.3	1	0.3	1
5 - 6	Shallow Waters	0.5	1	0.6	1
5 - 6	Onshore	0.7	1	0.7	1
7 - 13	Deep Waters[1]	0.37	0.55	0.55	0.65
7 - 13	Shallow Waters[1]	0.51	0.6	0.63	0.7
7 - 13	Onshore	0.7	0.8	0.77	0.85

[1] Threshold between shallow and deep waters is 100m.

After the auction, the winning firm pays the bonus and starts the exploratory period, when the operator performs seismic tests and drills wells in order to find out signs of hydrocarbons, and is subject to the MEP bid or the MEP requirement of the tender, and to the percentage of local content. If the consortium considers the production as feasible at the end of the exploratory period, it submits a Declaration of Commerciality to ANP, and then a Development Plan. It is in this moment that the oil field gets a commercial name. Once approved by ANP, the development stage of the production phase begins, when the production wells start to be drilled and all necessary equipment, such as platforms, are set up. This is the most expensive moment in this industry, and, therefore, when the local content requirements will mostly affect the investment decisions. Finally, when the "first oil" is produced, the field is considered in production stage. The lease usually expires in 25 years, but can be renewed pending new investments.

Table 3: Summary statistics of field production

Statistic	Onshore	Shallow	Deep
Mean	2,065.51	10,025.58	95,258.87
	(458.44)	(2,220.00)	(25,855.67)
Standard Deviation	7,913.84	17,620.73	163,525.61
Median	103.58	3,179.43	27,286.91
Min	0.08	5.31	48.97
Max	86,956.38	106,772.63	778,614.77
Quantiles			
10	3.81	208.58	1,049.79
25	14.02	904.87	6,966.60
75	743.31	11,176.09	78,152.76
90	3,078.34	24,177.95	312,181.12
95	9,899.17	48,684.63	431,000.45
99	37,052.18	75,433.90	661,430.97

Note: Values in million R$. Standard errors in parenthesis.

2.2 Data

In this study we used three different data sets: oil and gas auctions; oil fields output; price for the oil and gas produced by each oil field, adjusted by quality.

Data on auctions was collected from ANP and cover all auctions held in the 12 sales that were held between 1999 and 2015[3]. It includes characteristics of each tract available in the auctions, including basin, sector, area (km^2); auction requirements, as the minimum bid in each dimension and required firm expertise; and bid information, including signing bonus (R$), local content for the exploratory and development phases (%), minimum exploratory program (units), identity of bidders, operator firm and share of each bidder when in a consortia. For each tract there is a conversion table that converts units from the minimum exploratory program to R$, which is used to establish the financial guarantees the winning firm must submit. All values in R$ were deflated to 2017 R$ using IPCA.

Production data was also obtained from ANP, and include the monthly output of each oil field since 1941. It discriminates between oil and natural gas, and includes the average oil API. The data on natural gas details how much was burned, consumed on site, re-injected in the well and the remaining output, which is the amount considered for royalties payment. As we are interest in the production value of each tract, it is this last measure that we use when considering natural gas. All data is available in cubic meters or thousand cubic meters, and were converted to barrel or barrel of oil equivalents (boe) using ANP guidelines.

One issue that arises is that production data is available by the oil field commercial name, and auction data is organized by tracts code. In order to merge both data sets, we use the Declaration of Commerciality, which is mandatory for tracts that go from exploratory to production stages, and states both the tracts' code and the fields' names.

ANP also provides a reference price for the oil and gas production of each field in Brazil, in R$. Based on the international prices, this data is useful because it controls for the quality of the

[3]The 8th round, partially held in 2006, was later annulled in courts.

hydrocarbons produced: for example, light oil can be significantly more expensive than heavy oil, and hence oil fields with a higher probability of producing light oil should be similarly more valued in auctions. This is relevant to the Brazilian case as there is relevant heterogeneity in the quality of oil. In average, field specific prices were 8% inferior to the Brent for the period 2008-2017, but the highest quality fields had on average a 5% premium on the international benchmark. On the other hand, fields of lower quality were offered a price 24% lower than the Brent.

ANP provides oil prices for the 2008-2017 period, and gas prices for 2010-2017, although for some months the information was unavailable. For these months, we calculated the average differential between the field-specific price and Brent crude for the available sample, and multiplied this value by the Brent price on the missing month. Then, data base is linked to production data using the contract number, which is successful for more than 99% of the monthly production. For the missing cases, we impute the average price of fields in the same basin. If there is no other producing field, we assign the Brazilian average.

2.3 Bidding rounds and bidder behavior

The bidding rounds can be arranged in three different groups, organized by rules and similar tract's characteristics: first, the rounds 1 to 4, organized in 1999 to 2002; rounds 5 and 6, in 2003 and 2004; and rounds 7 to 13, from 2005 to 2015. As presented earlier in Tables 1 and 2, the major changes in auction rules happened in the 5th and 6th bidding rounds, such as the increase in the weight of local content and the introduction of the minimum exploratory program as a score dimension.

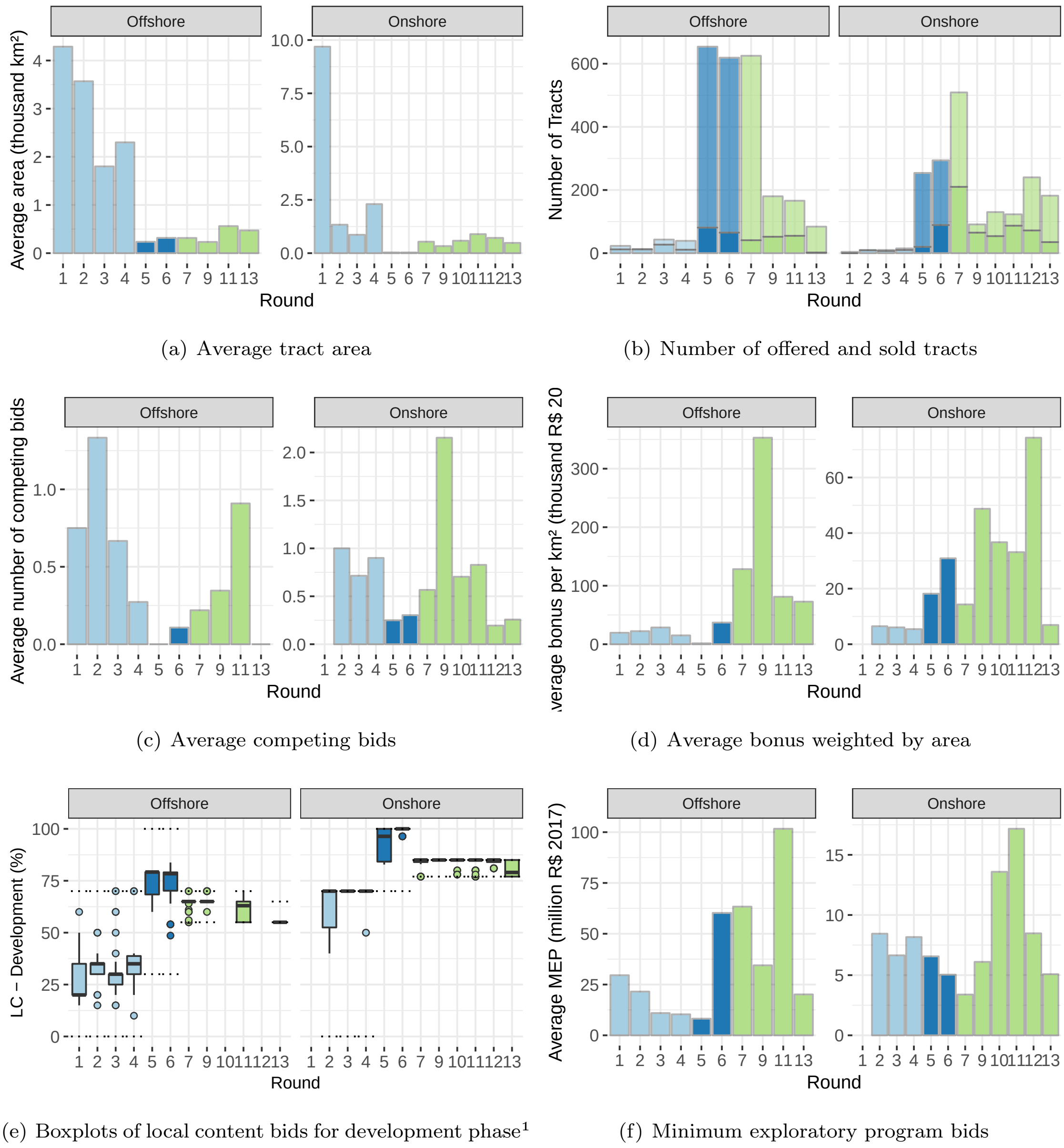
In addition to these shifts, there were also innovations in the characteristics of offered tracts, as seen in Table 4. The most noticeable were a drastic decrease in the average tract area and a major boost in the number of tracts available for leases. In other words, instead of few very large tracts, the government option was to offer many small blocks, with the total acreage relatively constant across bidding rounds.

The theoretical effect of the reduction in the tract size on competition is at first sign unknown, whereas the potential reduction in costs could lead to a higher participation of small firms. On the other hand, it might offset economies of scale, as what could optimally be a single production area could now have several different firms operating. As for the expansion in the number of offered areas, we could expect that part of these would not be attractive to bidders, but even if all were, interested firms might not have the resources to investigate the prospects in all of them, so we would expect a decrease in the proportion of tracts being leased, as observed by Haile et al. (2010) for the leases in the United States. They note that there is a reduced number of bidders even in the most appealing tracts in the sale, as competition is spread in more areas. A further discussion on both topics is available in Hendricks and Porter (2014).

In the first four rounds, 157 tracts were offered for lease, and 88 were successfully sold. Leased areas received on average 1.78 bids. The mean bonus was R$ 39.9 million. Overall, R$ 4.3 billion were generated in revenue for the government in these sales. The minimum exploratory program was fixed, and averaged R$ 14 million for the leased tracts. The local content bids were, on average, 33% and 43% for exploration and development phases, respectively.

This overall figures can vary significantly depending on the location of the tracts, as can be seen on Figure 2. Particularly, we can see that offshore tracts are much more expensive than onshore

Figure 2: Statistics of tracts auctions in Brazil



(a) Average tract area

(b) Number of offered and sold tracts

(c) Average competing bids

(d) Average bonus weighted by area

(e) Boxplots of local content bids for development phase[1]

(f) Minimum exploratory program bids

Note: The 8th round was annulled in courts. Rounds 10 and 12 had only onshore tracts available.
[1]Dotted lines specify the minimum and maximum bids.

Table 4: Characteristics of auctions by round group

Variable	Rounds 1-4	Round 5-6	Rounds 7-13
Average area per tract (km^2)	2563.95	199.49	487.76
Average area per round (thousand km^2)	144.86	185.53	227.62
Average number of offered tracts	39.25	910.50	388.33
Average number of leased tracts	22.00	127.50	112.17
Proportion of leased tracts	0.56	0.14	0.29
Average number of bids	39.25	147.00	190.33
Average bids per offered tract	1.00	0.16	0.49
Average bids per leased tract	1.78	1.15	1.70
Average bonus (million R$)	39.87	5.97	11.89
Average bonus per km^2 (thousand R$)	18.01	23.22	61.09
Average local content - exploration (%)	33.24	81.45	71.71
Average local content - development (%)	43.00	85.66	79.99
Average MEP bid (million R$)	14.31	19.56	20.64
Average MEP bid per km^2 (thousand R$)	12.29	111.57	128.71

tracts and exploration costs are also considerably higher. On the other hand, local content bids were markedly lower for offshore tracts due to higher costs, averaging in the first rounds around 30%, compared to 70% for almost all bids for onshore areas, the maximum allowed in those sales.

In the 5th and 6th round, 1,821 tracts were offered, of which 255 were leased, 14% of total. The average number of bids was 0.16, and 1.15 when restricting to sold tracts. The mean bonus was only R$ 6 million. On the other hand, local content bids increased remarkably, reaching more than 80%. Average minimum exploratory program, which started to feature as a bid dimension, increased compared to the previous rounds, which is significant given that tracts became a lot smaller. The decrease in participation was even bigger for offshore tracts, lowering from 0.9 bids per tract to 0.12. Average revenue dropped from R$ 57 million to R$ 6 million, and in offshore areas the average decreases even when we take into account the much smaller areas being offered. For onshore tracts, the value per km^2 increases, but that is because the areas were abnormally small in these sales, around $32km^2$.

From the 7th to the 13th round, there were 2,330 areas offered and 673 were sold. The proportion of leased tracts hiked to 0.29, the mean number of bids to 0.49, and to 1.7 in the leased tracts. The signing bonus bids expanded to R$ 11.9 million. Local content bids decreased slightly to 80% in the development stage. Minimum exploratory program rose slightly to R$ 20 million.

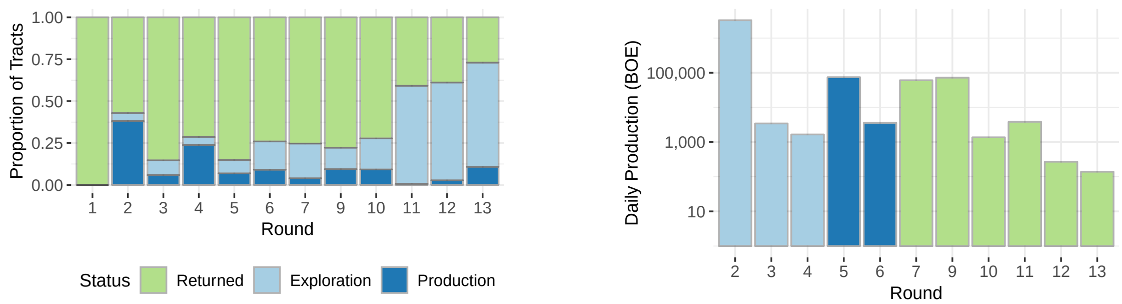
In these sales, the composition of tracts greatly influence the results, as there were more onshore areas available. When restricting the sample to offshore tracts, average bonus grew from R$ 9 million to R$ 60 million. More strikingly, the minimum exploratory program bids surged from R$ 30.2 million to R$ 78.3 million.

The significant changes in participation and bid behavior along the rounds had several causes. One key part of the puzzle is oil prices: its continuous increase beginning in 2005 and peaks until 2014 certainly explain part of the bonus rise in rounds 7-13. Other factors affecting these sales were the euphoria induced by huge discoveries in tracts leased in the 2nd round and the emergence of new competing firms, most notably OGX. It seems, however, that the increased competition was at least partly relocated from signing bonus to the minimum exploratory program, which was far higher than the fixed requirements of the first rounds. This is an evidence that the multidimensional bid affected critically the behavior of firms in the auctions.

The scoring rule also appear to have affected bids in auctions held in 2003/2004. The external factors previously cited did not happen until then, and, in particular, the oil prices were relatively flat at that time. There was a significant turmoil in Brazilian economy around the elections in 2002, but most of the effect had already dissipated before the sales: the exchange rate was 2.71 R$/US$ in June 2002 and had risen slightly to 3.00 R$/US$, after peaking in 3.99 R$/US$ in October 2002. Part of the decrease in participation is probably due to the great expansion in the number of offered tracts, which would be according to the evidence in the United States (Haile et al. (2010)). In this case, however, firms were in fact retreating from shallow water areas in favour of more lucrative deep-water tracts. In Brazil, there was literally no competition for Petrobras in these areas, as it was the sole bidder in the 5th round. Also, it is possible to compare with the 7th round, which also had a large number of offered tracts, 1,134, but with more mild local content rules. In this case, the proportion of leased tracts grew to 22%, with an increase in the number of bidders and in revenue. It is also remarkable that even with the great reduction in the size of the tracts, the bonus weighted by area actually decreased in the 5th round, and was similar to the first four sales in the 6th round.

Another possibility for different bidder behavior is that there was a perceived difference in the value of tracts offered in each round. With current data, it is hard to dismiss this hypothesis, as several tracts are still being prospected for oil, and it is not possible to reliably forecast its production. Figure 4(a) shows the proportion tracts in each stage as of 2017. We can see that it is impossible to reach any conclusion regarding the most recent sales, and even for old rounds there are still several tracts still being explored. However, we can see in Figure 4(b) that, except for the 2nd round, that is an outlier due to the pre-salt discoveries, the tracts leased in the 5th and 6th rounds have production similar to the ones sold in other rounds.

Figure 3: Production statistics per auction round



(a) Proportion of tracts per production stage in 2017

(b) Average 2017 oil output per round

3 Model

3.1 Model description

We assume a common value framework, that is, the value v of the tract is unique for all firms, but unknown until after the auction. Each firm i has a signal t_i, and conditional on v signals are identically and independently distributed. The value distribution is known by all competitors. Each signal t_i is an unbiased estimator of v, that is, $E[t_i|v] = v$. This is the mineral rights model developed by Wilson (1969, 1977) and Ortega-Reichert (1968), and later generalized for a context with interdependent values and affiliated signals by Milgrom and Weber (1982).

We allow for endogenous participation, assuming that there are n exogenous potential bidders which can choose whether to submit a bid or not. We also assume that the bidders strategy is independent across auctions, that is, the bid for one tract does not depend on the firm's bid for another, or whether the firm won a third area.

Bidders draw i.i.d. unidimensional signals t from a distribution $\Phi(t|v) = N(v, \sigma^2)$. In order to win the license, it submits a multidimensional bid (b, ℓ, p): b is the signing bonus, in R\$, $\ell \in [0, 1]$ the proportion of local content, and p is the minimum exploratory program, in R\$, and obtains a score $s_i = s(b, \ell, p)$. There is a lower bound for the signing bonus, denoted by $\underline{b} > 0$. The minimum exploratory program may also be constrained, depending on the auction rules, and the bounds are expressed by $\underline{p} \geq 0$. In some auctions, p is fixed, such that $p = p^*$. Local content is subject to lower and upper bounds, such that $0 \leq \underline{\ell} \leq \ell \leq \overline{\ell} \leq 1$.

We assume the following cost structure for the firms:

$$C = \max\left\{p, [\overline{c}\ell + \underline{c}(1-\ell)] \cdot v\right\} + c_{part} + b, \tag{1}$$

where $\underline{c}$ means the marginal cost of sourcing abroad and $\overline{c}$ is the marginal cost of local supplies, and $0 < \underline{c} \leq \overline{c} < 1$. We assume that the marginal costs are constant[4]. The parameters can be interpreted as the share in the value of production that is spent to drill the oil. We assume that the cost is linear on the value of the tract, that is, higher output requires higher drilling investments by the same proportion. In this fashion, a high local content bid means that, if the tract contains any oil, the firm has to pay more to extract it. This extra cost is proportional to the difference $\overline{c} - \underline{c}$. We also assume a fixed cost, c_{part}, not affected by local content rules, which is paid by every company that submits a bid.

As for the minimum exploratory program, we assume that it is a sunk cost when the tract is productive. In other words, if there is feasible production in the area, the firm would have to make significant exploratory efforts independent of its p bid, and the only relevant costs are given by the interaction of its local content bid with local and foreign costs of supplies. Contrarily, the minimum exploratory program is binding when production in the tract is not feasible.

In summary, the timing of the model is as following: ANP decides to auction a certain tract with value v, of which n firms acquire signals t_i. Firms with signal above a certain threshold pay the participation cost c_{part} and submit bids b, ℓ and p. The firm with highest score $s(b, \ell, p)$ wins the auction. The winning firm then observes v and obtain $\pi = v - max\{p, [\overline{c}\ell + \underline{c}(1-\ell)] \cdot v\} - b - c_{part}$. Losing bidders obtain $\pi = -c_{part}$ and firms that declined to participate have payoff zero.

[4] Asker et al. (2019) also assume constant marginal costs for the oil industry.

We also developed an alternative model, fully described in Appendix B. In this model, we have an extra parameter, c_{exp}, which describes exploration cost, and a slightly different time-line. After the auction, the winning firm always pays p, and only then observes v: if it chooses not to produce, its payoff is $\pi = -b - p - c_{part}$. If production is profitable, it develops the tract and obtains $\pi = v - b - c_{exp} - c_{part}$. Although the richer structure, the results of both models are similar, and we defer the full description to the Appendix.

3.2 Equilibrium

One implication of the common value structure is that we have to take into account the presence of the winner's curse. That is, the announcement of a firm as the winner means that it had the highest signal among all bidders, that is, its signal is a biased estimate of the tract's true value. To deal with this possibility, in equilibrium firms submit bids that are inferior to its signal, and the magnitude of this curtailing depends crucially on the number of bidders and on the variance of the signals. If there are more firms participating, winning can be an even worse news, as it has the highest signal among more firms. Also, if the variance around v is larger, the firm also has to take into account a higher possibility of overbidding.

In this section, we will characterize the equilibrium for scoring rule composed of a bonus bid and an arbitrary number of other dimensions, which we will call x.

We designate the optimal choice as $\tilde{s}(t) = \tilde{s}(b(t), x(t))$. The highest signal of the $n-1$ competitors is denoted by y, and its corresponding score is $z = \tilde{s}(y)$. The density of z given t is given by $l(z|t) = l(\tilde{s}(y)|t) = f(y|t)/\tilde{s}(y)$, where f is the density of y conditional on t.

$V(x|t, y) = \tilde{V}(x|t, z)$ is the expected profit for winning the auction with bid x, given a signal t and a competitor with highest signal y. We note that it depends on x, but not on b. The expected profit before the auction given a signal t and a score $s(b, x)$ is

$$\int_0^{s(b,x)} \left[\tilde{V}(x|t, z) - b\right] l(z|t) dz \tag{2}$$

where $V(x|t, y)$ is given by

$$V(x|t, y) = \int [v - C(x)]\, h(v|t, y) dv. \tag{3}$$

In this setting, $h(v|t, y)$ is the density of the value v given a signal t and a highest signal y for the $n-1$ competitors, and $f(y|t)$ is the density of the highest signal among the opponents y, given a signal t.

Then, the firm maximizes equation 2. In a symmetric equilibrium, all firms use the same strategy. Writing the FOCs in terms of y e multiplying by $\tilde{s}'(t) > 0$ we obtain[5]

[5]This requires that the score s must be monotonically increasing in t. This assumption is not necessary for each dimension of the bid.

$$\frac{\partial s}{\partial b}\left[V(x|t,t)-b\right]f(t|t)-\tilde{s}'(t)F(t|t)\begin{cases}=0, & b>\underline{b}\\ \leq 0, & b=\underline{b},\end{cases} \tag{4}$$

$$\frac{\partial s}{\partial x}\left[V(x|t,t)-b\right]f(t|t)-\tilde{s}'(t)\int_0^t \frac{\partial}{\partial x}V(x|t,y)\ f(y|t)dy\begin{cases}\geq 0, & x=\overline{x}\\ =0, & x\in(\underline{x},\overline{x})\\ \leq 0, & x=\underline{x}\end{cases} \tag{5}$$

In the case of a linear scoring rule, as we discuss in the next section, we have $s=b+S(x)$, where the weight of the signing bonus b is normalized to 1. In this case, $s'(t)=b'(t)+S'(x)x'(t)$, given that $b>\underline{b}$.

If bid on dimension x is maximum or minimum, $x'(t)=0$. In this case, the FOC with regard to b becomes the ordinary differential equation (ODE)

$$[V(x|t,t)-b]f(t|t)-b'(t)F(t|t)=0, \tag{6}$$

which is the solution for a standard first-price auction.

When $x\in(\underline{x},\overline{x})$, both FOCs have to be satisfied with equality. In this case, we combine them to obtain

$$F(t|t)S'(x(t))=\int_0^t \frac{\partial}{\partial x}V(x(t)|t,y)\ f(y|t)dy \tag{7}$$

From this expression we can obtain $x(t)$ and $x'(t)$, and the new modified ODE is

$$[V(x|t,t)-b]f(t|t)-[b'(t)+S'(x)x'(t)]F(t|t)=0. \tag{8}$$

In summary, this equilibrium description allows us to solve the model given a scoring rule $s(x)$, a value distribution F_v, an exogenous number of bidders n and distributions $f(y|t)$ and $h(v|t,y)$. In the next section we will discuss how we estimate these objects and the model.

4 Estimation

4.1 Scoring formula

The scoring formula in all auctions, except for the ones in 5th and 6th rounds, was given by the following equation:

$$score=\left[\frac{b}{\max_j(b)}w_b+\frac{\ell_{exp}}{\max_j(\ell_{exp})}w_{\ell_{exp}}+\frac{\ell_{dev}}{\max_j(\ell_{exp})}w_{\ell_{dev}}+\frac{p}{\max_j(p)}w_p\right]\cdot 100,$$
$$j=1,...,i,...,n \tag{9}$$

where the denominator is the maximum bid in that dimension among the n bidders. Thus, if a firm has the highest bid in all dimensions, its score is 100. Meanwhile, the formula for the local content component in the 5th and 6th rounds was slightly more complicated:

$$PEXP = p \cdot \left[\left(\frac{\ell_{exp}}{min\ \ell_{exp}} \right)^2 - 0.8 \right] \tag{10}$$

$$PDEV = \left(\frac{\ell_{dev}}{min\ \ell_{dev}} \right)^5 - 0.5 \tag{11}$$

where the denominator is the minimum requirement for the local content on those auctions. Then, these indexes are used in the equation 9 instead of the local content bids themselves.

These scoring formula presents a challenge for solving the model equilibrium, as the score of firm i depends not only on the score of its competitors, but on each dimension of their bids. In order to reduce the level of complexity, we opted instead to assume a linear scoring rule, which assumes the following form:

$$\widehat{score} = b + \widehat{w_\ell}\ell + \widehat{w_p}p \tag{12}$$

These new weights are estimated from auction data, and the weight of the signing bonus can be normalized to one. Another simplification is that we reduce the dimension of the local content bids to one, instead of different bids for the exploration and development phases[6]. As the correlation between both bids is very high ($\rho = 0.95$) this is unlikely to impact on the results.

The procedure to obtain the weights $\widehat{w}$ is the following: first, we recover the score $\in [0, 100]$ in each dimension of the bid, according to equations 9, 10 and 11. Then, we regress each of these scores against the bid in that dimension. In the case of local content, we take a weighted average of the bids for the exploratory and development phases, in which the weights are given in the tender protocol. And, in the case of the minimum exploratory program we use the value in R$ of the bid, instead of its conversion in units.

Table 5: Regressions of the scores against the respective bids

		Scores	
	Bonus	Local Content	MEP
Bonus (R$ million)	0.31*** (0.05)	-	-
Local Content (p.p.)	-	0.29*** (0.02)	-
MEP (R$ million)	-	-	0.21*** (0.03)
Observations	921	921	810
R^2	0.041	0.195	0.045

Note: ***Significant at the 1 percent level.

In spite of the low R squared of the regressions, in 984 out of 1,016 auctions the winner remains the same as in data. After performing the regressions, we multiply the estimated coefficients by the weights of Table 1 and normalize the signing bonus weight to 1. The final weights are available in Table 6. The coefficient is interpreted as how much points the firm would make if it bids: R$ 1

[6]To convert the local content bids in the data, we simply take the weighted mean of the bids for exploration and development phases. The relative weights are the same of the original scoring rule, presented in Table 1. Also, in most auctions the bounds for the local content bids are different for the exploration and development stages. In this case, we also took the weighted mean between the bounds for each phase.

Table 6: Estimated weights

	Signing Bonus	Local Content	MEP
1 - 4	1	0.28	0.00
5 - 6	1	2.15	0.96
7 - 13	1	0.81	0.96

Note: the coefficients are interpreted as the score increase when the firm bids an extra R$ 1 million in bonus, 1 additional percentage point in local content or more R$ 1 million in minimum exploratory program (MEP).

million extra of signing bonus, 1 extra percentage point of local content and R$ 1 million extra of minimum exploratory program. The results adhere to expectations: we can see a dramatic boost in the role of local content in the 5th and 6th rounds followed by a marked decrease afterwards, while still being more relevant than in the first four rounds.

4.2 Value Distribution

We estimate the value distribution F_v by fitting a log-normal distribution to the available production data via maximum likelihood, using decline curves to forecast production for fields currently in operation. We split the data in three categories: onshore, shallow waters and deep waters.

If we could observe the amount of oil and gas available in each auctioned tract it would be possible to estimate it non-parametrically. However, data on production is truncated, as only fields above a certain threshold are developed. Instead, we assumed a log-normal distribution, which shape takes into account that most of the oil deposits are never developed. The log-normal assumption has been widely used within the oil industry, and has a good fit to several areas around the world[7]. In Figure 4 we can see that for onshore areas the density plot clearly resembles a normal when the x-axis is in logarithmic scale. As for the tracts in shallow and deep waters, the graph shows a skew to the left, although that is mostly due to fields which have just started to being developed, and our measure of value is not accurate.

On the other hand, the use of the log-normal distribution assumes that virtually all tracts auctioned have some oil deposits, albeit possibly very small, while in reality we observe a majority of tracts being explored without any findings. To deal with this pattern, we need a sample proportion of tracts to which we will impute null value. We have two different measures that could account for this effect: the average rate of commerciality and the average hit rate. The first measure gives the proportion of tracts that were deemed commercial by the winning consortia. Then, we could simply assume that every tract that was not developed was worthless. The problem with this approach is that it tends to be too strict, as many returned tracts may have a positive value, although at the time of exploration the leasers might not have thought it was profitable to develop the field, due to technological, financial or other reasons. As such, we could instead impute null value only to the tracts that did not register a hit during exploration. The issue here is that we do not observe the value of these tracts that were not further developed, and have to rely on the functional form of the log-normal distribution to account for the share of 13% to 32% (see Table 7)

[7] Sorrell et al. (2012) discuss the use of the log-normal distribution in this context.

percent of tracts with low unobserved values that could significantly change the distribution. We experimented with both measures, but using the hit rate generated a distribution with significant probabilities for very high values, and so we opted to be more conservative and use instead the average commerciality rate.

Then, the pdf for each location k is given by:

$$f_v^k = (1 - \overline{comm}^k) \times 0 + \overline{comm}^k \times p^k(v), \tag{13}$$

$$p^k(v) \sim Lognormal(\mu, \sigma), \tag{14}$$

where $\overline{comm}$ is the proportion of tracts that were declared commercial within each location.

Another issue is that the majority of relevant oil fields are still in production, and we need to forecast its future output in order to have a proper measure of the value of each tract. With this objective, we use a method called Decline Curve Analysis both for oil and gas forecasts. The basic idea is that once a well is drilled, the high pressure in the reservoir pumps oil to the surface, and the field quickly reaches the maximum rate of production. From this moment on, the pressure decreases and oil is pumped in a rate that decreases constantly, and this rate can be forecast by a hyperbolic curve. A full description is given on the Appendix, but is suffices to say that in the most relevant oil fields it performs well, including out-of-sample. Some issues arise when the field production has not yet peaked; when new wells are drilled or when a new connected reservoir is found. In the first case, we assume that the last observation is the peak, and use the decline rate of comparable fields, with reasonable results. In the other cases, we use the last peak of production instead of the highest peak, but the method performance may be poor.

Once we have an estimate of the total output of each field (in barrels), we need to multiply this by the relevant prices in order to have a measure of its value. For the observed production, we use the monthly field-specific prices provided by ANP, while for the production forecast we use the last observed price. An advantage of using tract-specific prices is that we incorporate the quality heterogeneity among the tracts available in the auctions, as well as the variation in both international oil prices and exchange rate.

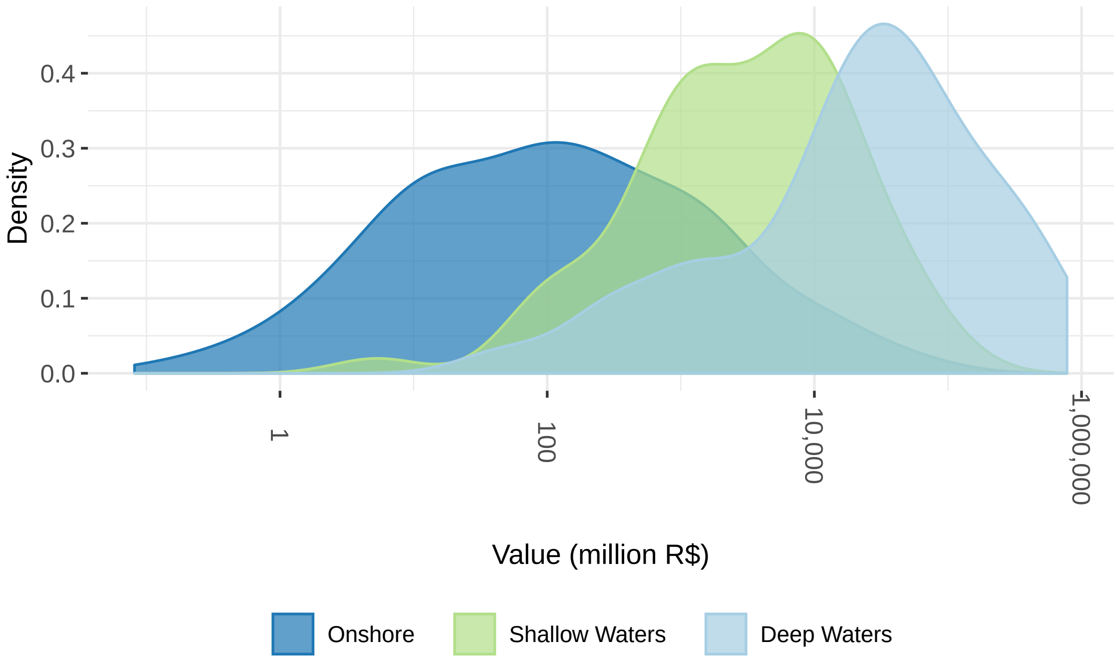
Using the data on field value, discarding the fields with less than a year of observations, we estimate the log-normal distribution separately for onshore, shallow waters and deep-water fields via maximum-likelihood[8]. The results are presented in Table 7 along with the parameters we imputed, as in Equation 13. Some moments and percentiles of the distributions are given on Table 8. The cumulative distribution functions are shown on Figure 5.

We note that Table 8 is different than Table 3, as before we presented empirical quantiles that included only developed fields, and now we are presenting the theoretical distribution, which includes the high probability of a dry hole. As such, when we compare the same quantiles in both tables, we see that the values are smaller in the theoretical distribution[9]

[8]Note that we must assume that one tract, if viable, turns into one single oil field, which is true for around 80% of the fields declared commercial.

[9]This pattern will change when we reach quantiles above the maximum of the empirical distribution, when our theoretical distribution will still attribute a positive, albeit small, probability of finding a tract with a value above all others.

Figure 4: Density curves of tract value per location



Note: values on the x-axis are in logarithmic scale.

Table 7: ML estimates for Log-normal value distribution function

stat	Onshore	Shallow	Deep
μ	4.664	7.921	9.897
	(0.155)	(0.239)	(0.355)
σ	2.684	1.9	2.242
	(0.11)	(0.169)	(0.251)
Average Commerciality Rate	0.142	0.074	0.054
	(0.017)	(0.021)	(0.021)
Average Hit Rate	0.274	0.264	0.375
	(0.022)	(0.035)	(0.046)
n	298	63	40

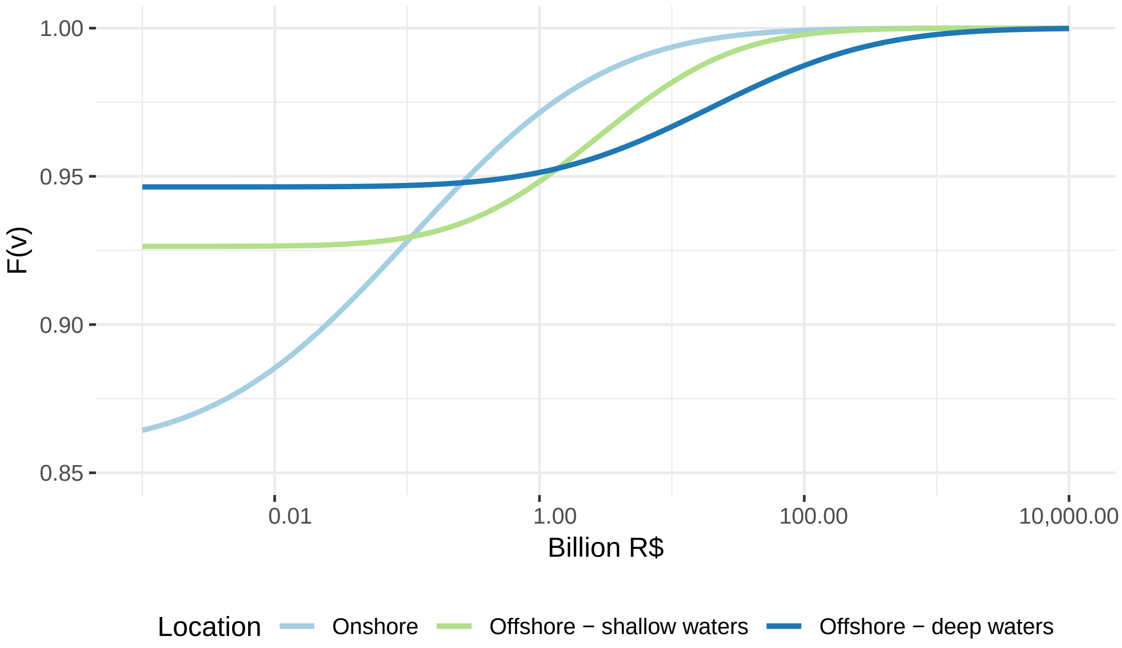
Note: Standard errors in parenthesis.

Table 8: Summary Statistics for Log-normal Value Distribution

stat	Onshore	Shallow	Deep
Mean	550.54	1,233.18	13,158.91
Standard Deviation	32,602.78	17,326.78	429,667.50
Quantiles			
75	0.00	0.00	0.00
90	24.64	0.00	0.00
95	291.13	1,137.52	686.33
99	5,495.88	22,239.07	146,341.54

Note: all values are in million R$.

Figure 5: Estimated cumulative distribution of production per tract location



Note: values on the x-axis are in logarithmic scale.

4.3 Model

For estimating the model, we must impute an exogenous number of potential bidders, n. Our main procedure was to estimate the model for different values of n and choose the one with the better fit. In the robustness tests we will present the results while varying the number of potential bidders. Another possibility would be to use the number of firms that registered for each bidding round as the number of potential bidders. However, in most of them there is no indication for which location the firm is allowed to participate, and the data show that onshore tracts attract more different bidders than offshore areas. We also tried to use the number of different firms that bid for at least a tract in each group of bidding rounds, but the results also showed a worse fit than when assuming a fixed value.

For a given n, we can estimate the distributions $h(v|t, y)$ and $f(y|t)$. $h(v|t, y)$ is the density of the tract value being v conditional on the firm having a signal t and the highest signal of the $n-1$ competitors being y. $f(y|t)$ is the density of the highest opponent signal y given a signal t. They are defined by the following formulas:

$$h(v|t, y) = \frac{(n-1)\phi(t|v)\phi(y|v)\Phi(y|v)^{n-2}f_v(v)}{\int (n-1)\phi(t|u)\phi(y|u)\Phi(y|u)^{n-2}f_v(u)du} \tag{15}$$

$$f(y|t) = \frac{\int (n-1)\phi(t|u)\phi(y|u)\Phi(y|u)^{n-2}f_v(u)du}{\int\int (n-1)\phi(t|u)\phi(s|u)\Phi(s|u)^{n-2}f_v(u)duds}, \tag{16}$$

where $\Phi(t|v)$ is the distribution of the signals and F_v is the distribution of tracts value. We have already estimated function F_v from production data, and we assume that $\Phi(t|v) = N(v, \sigma^2)$. So, given signals t and y we can calculate equations 15 and 16. As stated in the previous chapter, in equilibrium firms assume $y = t$, so from here on we will not distinct between both.

Then, we can also calculate the expected value of the tract minus the production costs:

$$V(\ell, p|t, t) = \int [v - max\{p, (\bar{c}\ell + \underline{c}(1-\ell))v\}]\, h(v|t, t)dv, \tag{3}$$

also for a given t, costs $\bar{c}$ and $\underline{c}$, and bids ℓ and p.

With these estimates, we move to the FOCs in order to compute the optimal bids given t: $b^*(t)$ and $\ell^*(t)$. Our model would allow for endogenously calculation $p^*(t)$, but our first estimates performed very poorly. This was because we considered p as sunk cost, imposing no bounds, and when a firm had a high enough signal it could make a huge p bid and have a low probability of having to pay for it. We developed an alternative model, described on Appendix B, when we impose such a bound. Given this, and as our focus on this work was on local content, we decided on a further simplification, calculating p simply as an affine function of the signal t_i.

Given this parameters, we know that ℓ has only corner solutions, so we only have to evaluate the derivatives in both possible results to obtain ℓ^*[10]. Then, prior to solving the bonus differential equation, we have to take into account the boundary condition $b > \underline{b}$. That is, the firm only choose to submit a bid if $V(\bar{l}, \underline{p}|t, t) > \underline{b}$. The signal $\underline{t}$ in which this inequality is first satisfied is the starting point of the Euler's numerical method to solve the differential equation.

In summary, fixing the number of potential bidders n, we have for each signal t a decision whether to participate or not in the auction as well as bids $b^*(t), \ell^*(t), p^*(t)$ and a score $s(t)$, given the parameters of cost, $\bar{c}$ and $\underline{c}$, and a variance for the signal distribution conditional on v, σ^2.

To estimate these parameters with auction data, our procedure is to first recalculate the score of the bids for each tract: instead of the nonlinear formula actually used, we calculated what would be each score using our linear fit. Thus, for a given set of parameters, we invert function $s(t)$ so that we know the signal a firm would have in order to obtain the score estimated in the data. Then, if for s^{-1} the firm chooses to participate, we obtain $b^*(s^{-1}), \ell^*(s^{-1})$ and $p^*(s^{-1})$. Also, we can compute the probability of participation, which will be given by

$$P(part) = 1 - \int_0^{\infty} \Phi(\underline{t}|v) f_v \; dv, \tag{17}$$

that is, the unconditional probability of a bidder to have a signal $t > \underline{t}$.

To estimate the parameters $\bar{c}, \underline{c}$, σ^2 and c_{part} (and, in Model 2, c_{exp}) we perform a minimization of the distance between the bids predicted by the model and the actual bids seen in the data, also including the distance between the predicted and actual participation, as in equation 18. We use a standard Nelder-Mead algorithm in order to find the optimal parameters.

$$d = \begin{pmatrix} \widehat{b(t)} - b \\ \widehat{\ell(t)} - \ell \\ \widehat{p(t)} - p \\ \widehat{part} - part \end{pmatrix} \mathbf{W} \begin{pmatrix} \widehat{b(t)} - b \\ \widehat{\ell(t)} - \ell \\ \widehat{p(t)} - p \\ \widehat{part} - part \end{pmatrix}, \mathbf{W} = \begin{pmatrix} w_b & 0 & 0 & 0 \\ 0 & w_\ell & 0 & 0 \\ 0 & 0 & w_p & 0 \\ 0 & 0 & 0 & w_{part} \end{pmatrix} \tag{18}$$

In our main specification we use the weights of the estimated scoring rule (Table 6), available for the bonus (b), local content (ℓ) and minimum exploratory program (p), which give an economic

[10] Note that this result prevents us from evaluating if the scoring auction performs better than a standard first-price sealed auction with fixed local content requirements.

interpretation to the distance d. However, there is no obvious value to use for w_{part}. We dealt with this issue with two different solutions: in the first, in order to still benefit from the economic interpretation of the other three parameters, we simply impose an arbitrary weight to w_{part}, with size comparable to the other dimensions: 20 for deep-water tracts, and 5 for shallow waters and onshore tracts. Alternatively, we can obtain an asymptotically efficient weight matrix by iterating the GMM estimation and updating the weight matrix with the inverse of the squared residuals. We present this as a robustness test, in section 5.5.

4.4 Identification

Before showing the results, we will briefly discuss about the identification of each parameter in the model.

To identify the parameter σ^2, that is, the variance of the signal around the true tract value v we first rely on the signing bonus heterogeneity, available in data. In an environment with low signal variance, we would expect that the signing bonus bids would be relatively similar. On the other hand, high variability among bids for the same tract point to a larger variance.

The identification of the general level of costs is affected by the distance between the bids b and the true value v[11], as well as the winner's curse. That is, if the proportion of costs against the tract revenue is small, we would expect bidders to increase their signing bonus offers due to the higher profitability. Also, a higher variance of the signals would increase the role of the winner's curse, the fear that the bidder may be overvaluing the tract. In this case, they will reduce their bids in order to avoid receiving "bad news" if winning the auction.

As for the local and foreign costs, there are two margins for identification. The first is the difference $\overline{c} - \underline{c}$, which should be identified directly by the local content dimension of the bids. We must note that, as shown in Figure 2, in the onshore areas the majority of bids is in the upper bound, and we do not expect to find any significant difference between costs. In theory we would expect this difference to be smaller than in other areas, due to lesser complexity in the drilling equipment, but not zero. We speculate that this behavior is created by the non-linear scoring rule that takes into account the bids of the competitors, in which the score penalty for not bidding the upper bound is higher than the equivalent increase in the signing bonus. Nonetheless, for shallow and deep waters we believe there is enough variation to identify the cost difference.

Regarding the level of the cost parameters, it basically scales down the distribution of values. For instance, a lower cost level makes a tract more profitable to the bidders, which can increase their bids. Finally, the fixed cost c_{part} is identified mainly by the participation rates.

5 Results and Counterfactuals

5.1 Results

The results of the estimation for each location are available in Table 9. The standard errors were calculated using block bootstrap, clustered at the auction level. We vary the number of potential

[11] We note that we are not using in the estimation the observed value v, only its distribution, as described previously.

bidders and choose the model with the best fit, measured by the distance value provided by the GMM estimation.

Our main result is that there is a significant increase in costs for offshore fields when adopting local sourcing. We estimate an increase of 7 percentage points (14%) in deep-water areas, and 13 percentage points (16%) in shallow water areas. For example, in a deep-water oil field with 500 million boe, this difference means around R$ 8 billion in extra costs. In deep-water areas, the cost of sourcing locally is 56% of the tract value, compared to 49% abroad. For shallow waters, both proportions are higher, which point to a lower profitability. Here it is important to notice that a high local content requirement makes these areas completely unprofitable, preventing the development of otherwise lucrative oil fields. As for onshore areas, as discussed in the section 4.4, we do not identify any difference between local and foreign costs.

The next result is that the degree of uncertainty is very high. In each location, the standard deviation σ of bidders' signals is so large that even in tracts that prove to be massively profitable *ex-post* many firms opt not even to place a bid. This finding is consistent with the data, where we can find high competition for worthless areas and only one bid for tracts with large deposits. As for the magnitudes between each location, the variance is roughly proportional to the different expected values in each area: in onshore areas, with low oil potential, the variance is smaller than in deep-water offshore tracts.

On the other hand, when we compare the estimates with the standard deviation of the Log-normal value distribution of each location, in Table 8, we note that the estimates for onshore and specially shallow waters seem too high.

The estimate for the participation cost, c_{part}, grows consistently across locations, from R$ 2.2 billion in onshore areas, R$ 10.9 billion in shallow waters and R$ 24.1 billion in deep waters. However, we should be cautious when interpreting these values, as they include non-monetary components, due to the independence assumption across auctions. For instance, this could be caused by firms not having enough resources for submitting many bids in the same sale. However, as the participation rates are very low, the model interprets this a relatively high participation cost.

Table 9: Estimation Results

Variables	Onshore	Shallow Waters	Deep Waters
σ	84,854.28	488,702.93	323,061.51
	(4,500.23)	(342,895.15)	(107,201.19)
$\overline{c}$	0.75	0.94	0.56
	(0.06)	(0.12)	(0.06)
$\underline{c}$	0.75	0.81	0.49
	(0.06)	(0.09)	(0.03)
c_{part}	2,159.37	10,908.36	24,376.4
	(482.86)	(4,084.12)	(4,504.06)
# bidders	50	30	30
Observations	1,106	214	274

Note: values of sd and c_{part} are in million R$ of 2017. $\underline{c}$ and $\overline{c}$ correspond to the proportion of the tract value used to pay for exploration and development of tracts, as well as taxes. Standard errors are in parenthesis, obtained via block bootstrap clustered at the auction level.

Regarding the exogenous number of bidders, 50 for onshore areas, and 30 for both shallow and deep waters, our estimates are consistent with data. In the second column of Table 10 we present the number of different companies which submitted bids in at least one auction, and in the third column, we restrict the sample only to companies that were registered as operators. The smaller numbers we have found in our estimation are expected, given the expected turnover of firms in the Brazilian oil and gas market.

Table 10: Number of distinct bidders by location and rounds

Rounds	Onshore	Shallow Waters	Deep Waters
All bidders			
All rounds	89	37	50
1-4	16	19	27
5-6	10	4	12
7-13	77	24	34
Only Operators			
All rounds	66	27	37
1-4	14	14	23
5-6	9	4	7
7-13	57	18	24

In order to assess our estimates, we are going to compare them to an evaluation made by Almeida et al.(2016, 2017), of the Brazilian Petroleum Institute (IBP) which used the same location division as in this paper, with the addition of deep-water pre-salt areas[12]. For a given volume and location, they model the curve of production and the required infrastructure for the project, and used

[12] These are areas with same water depth as in other fields, but with drilling that goes up to 8 km deep, beneath the salt layer.

interviews with relevant companies to estimate the cost of each item. They assume a fixed signing bonus for each area. The estimates are in Table 11.

In the first two lines are the assumed tract value and the estimated break-even cost[13] for the barrel of oil[14]. IBP cost estimates do not include taxes, but they are included in our model. To improve the comparison, we decomposed our cost estimation between the real cost of supplies and direct taxes[15]. Given that the participation rate has a non-monetary value, as already discussed, we also present the estimates only for the variable costs.

Table 11: Comparison of IBP and model cost estimates

	Onshore*	Shallow Waters	Deep Waters (post-salt)	Deep Waters (pre-salt)
Volume	0.18	0.15	0.5	5
Break-even US$	NA	91	57	56
Costs (million R$)				
IBP	NA	22.3	41.7	367
Model - Total	26.5	54.5	78.2	553.6
Model - excl. tax	23	54.5	60.7	147.3
Model - var. costs	24.4	43.6	53.9	529.2
Model - part. cost	2.2	10.9	24.4	24.4
Profit share of tract's value				
IBP	0.37	0.2	0.23	0.21
Model	0.16	-0.10	0.21	0.41

Note: volume unit is million barrels of oil equivalent. Unit for value and costs is million R$, considering a US$ 50 barrel and a 4 R$/US$ exchange rate. Estimates for costs in the model include taxes, while IBP estimates do not. Break even is the estimated price that guarantees a 10% internal rate of return for the firm, accounting for costs and taxes.

* IBP did not present comparable cost estimates for onshore areas.

The comparison shows that our estimates for offshore deep-water tracts seem reasonable[16]. In post-salt areas, IBP costs were smaller than our estimation, which is expected, given that our measure includes taxes. However, our estimate of the firm's share in the tract value is almost the same as IBP's. While it may be hard to disentangle taxes and direct costs, our model has a good performance in predicting firms' total costs and its profit share. In pre-salt areas we underestimate the costs, but that is expected given that most of the tracts in our sample are in post-salt[17]. As for shallow waters, our cost estimate exceed the tract value, even at the higher break-even price. In fact, it would take a price of US$ 160 a barrel only to avoid losses. As for onshore areas, IBP did not present comparable cost estimates. When comparing the predicted profit share, our model seem to be overestimating the cost coefficients.

[13]The break-even cost include a 10% internal rate of return.

[14]The estimates for onshore areas were not comparable, as they assumed a natural gas production for electricity generation.

[15]We considered a 5% special participation rate for onshore and shallow water tracts, 12% for deep-water post-salt and 20% for pre-salt areas. We also accounted for a 34% income tax.

[16]We assumed a 90% local content bid for onshore areas, 60% in shallow waters and 50% in deep waters.

[17]After the discovery of oil in the pre-salt, tracts in this area were moved to another exploration regime, as described in Chapter 2

5.2 Counterfactuals

In this section we estimate the revenue the Brazilian government could have obtained in a scenario with no local content requirements. We estimate this counterfactual by imposing no local content commitments with the previous model estimates. As our model predicts that firms local content bids always have corner solutions, we are unable to make claims for the first four bidding rounds, when there was no minimum requirement and the optimal local content was almost always zero for offshore tracts.

The overall results are available in Table 12. The estimate for onshore tracts is that no further revenue could be achieved by lowering local content requirements, given that local and foreign costs are already similar. As for offshore tracts, the model predicts a large boost in revenue, estimated in R$ 67.1 billion for shallow waters and R$ 17.2 billion for deep-water tracts. Although in deep waters the oil fields are more valuable, this is more than compensated by the relatively higher cost differential estimated for shallow waters. We note that we are not including in this account tracts that were not leased but might have been in the absence of local content requirements. In this sense, we would expect that counterfactual revenue could be still larger.

Table 12: Counterfactual auction revenue

Variables	Onshore	Shallow Waters	Deep Waters
Original revenue	1,235.95	5,136.44	9,459.34
Counterfactual extra revenue	0	67,113.11	17,265.96
	(491.79)	(452,519.77)	(28,711.2)
Counterfactual revenue by round group			
1-4	0	0	0
	(4.05)	(0.33)	(14.87)
5-6	0	32,228.22	4,600.15
	(59.68)	(147,628.72)	(5,775.95)
7-13	0	34,884.89	12,665.81
	(78.96)	(95,688.49)	(9,509.62)
Participation Increase (%)	0	8.62	2.79
# bidders	50	30	30
Observations	1,106	214	274

Note: values are in million R$. Standard errors are in parenthesis, obtained via block bootstrap clustered at the auction level.

We note, however, that a full comparison of government revenue in both scenarios should include revenues on production, such as royalties and special participation, and corporate tax. As these would demand modelling production curves we are unable to say much, but as costs are discounted from the tax base, its reduction should further increase government revenue.

Regarding participation, our model predicts only minor increases, as presented in Table 12. As expected, we see no change in onshore areas, due to the absence of any difference between local and foreign costs. As for offshore areas, the increase is very small, of 8.6% in shallow waters and 2.79%

in deep waters. In our model, the participation threshold depends mainly on the participation cost, c_{part}, and as it is not affected by the local content policy in our structure, this results is not surprising.

In Figure 6, we present for each location how the local content requirements affect their signing bonus bids and expected profits. On the x-axis we report the expected tract value, given its signal, and plot the curves with no local content requirements and with the average commitment. We can see that for onshore tracts we do not observe any difference, given the similarity of the estimates for sourcing locally or abroad. For shallow areas, our cost estimates were so high that the model predicts that no firm will bid with an expected value below R$ 1.2 trillion, as the expected profit is negative. Regarding deep-water areas, the difference is also significant: companies start to bid when they predict a value of R$ 626 billion, R$ 20 billion less than when they have to comply to a 50% local content requirement. With a valuation of R$ 800 billion, for example, a firm would bid R$ 7.7 billion with no local content requirements, around 20% more than in the absence of such policy.

In Figure 7 we show the distribution of signal of the auction's winner for each location. We simulated 1000 times an auction centered on the true value of each tract and with the estimated standard deviation. As before, we assumed reserves of 180, 150 and 500 million boe for onshore, shallow waters and deep-water areas. We can see why bidders in shallow waters are so cautious: even in a less valuable area, the signal of the winner is usually higher than in deep-water areas.

Finally, in Figure 8 we can see how the extra profitability of the tracts in a counterfactual with no local content policies would be shared between firms and the government. In deep waters, our estimates show that the government share grows from around 10% in values that are relatively near the cutoff in which firms start to bid. When the values increase, the share increases and then remain mostly flat around 25%. In shallow waters, the government share is smaller, around 5%. However, we must notice that these are expected shares. *Ex-post*, we know that many tracts do not produce, and in such cases the firms have a higher loss, as the signing bonus was higher. Considering this, the government share is actually much bigger, as the government is able to extract larger rents from unfeasible tracts.

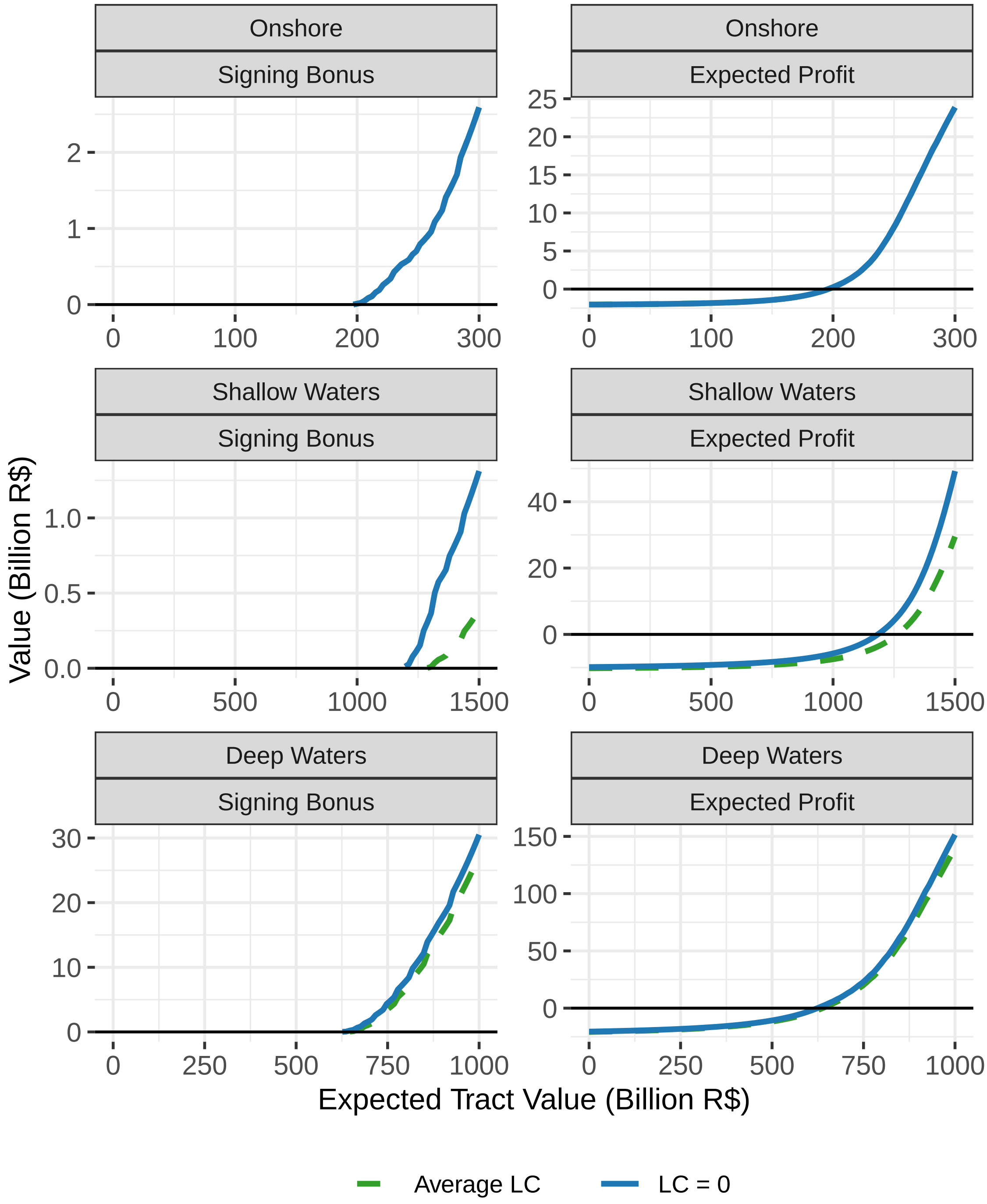
5.3 Robustness Tests

5.4 Number of potential bidders

In this section, we present model estimates for different number of potential bidders, n. Our previous results were estimated assuming 30 potential bidders for offshore tracts and 50 for onshore, based on a best fit criterium. In Table 13 we present model estimates for different values of n. In the first four columns we present the parameter estimates: the standard deviation of the signal around the true value[18], the foreign production cost, the local production cost and the participation cost. We also present the government extra revenue in a counterfactual with no local content requirements, as in the previous section, and a relative measure of the goodness-of-fit, given by the GMM estimation.

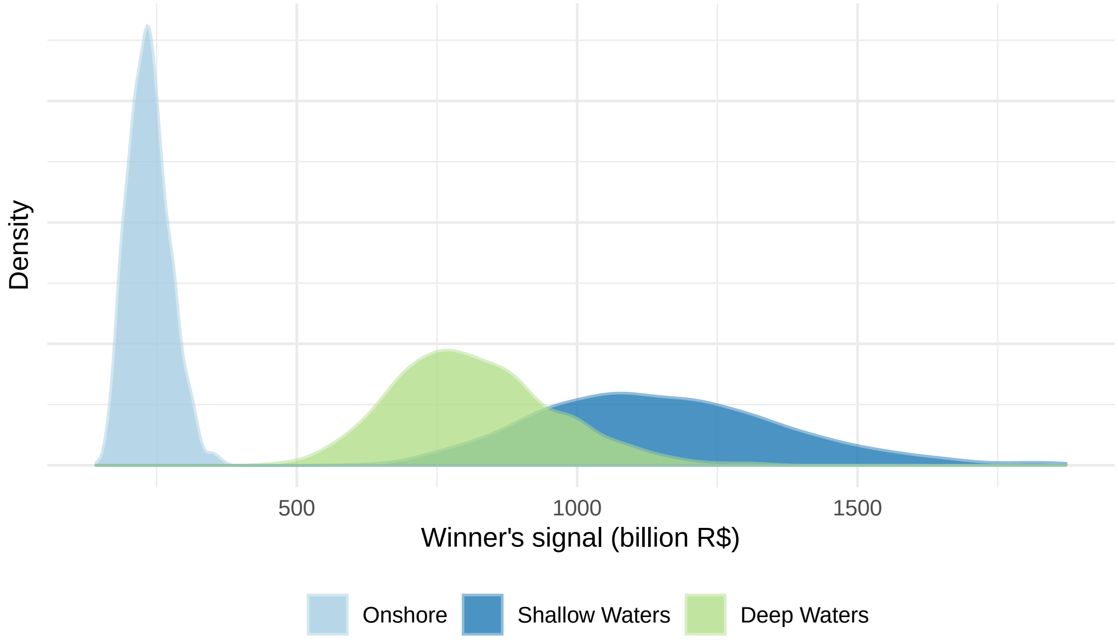
[18]Interpreted as the accuracy of the firms' tract value estimates.

Figure 6: Model estimates for signing bonus and expected profit with with and without local content requirements



Note: We considered a 90%, 60% and 50% local content bids for onshore, shallow and deep-water tracts, respectively. For simplicity, we also assumed that the reserve price was zero.

Figure 7: Distribution of winner's signals per location



Note: we assumed a R$ 200 price per barrel, and reserves of 180, 150 and 500 million boe for onshore, shallow waters and deep waters, respectively. We simulated 1000 times an auction centered on the true value with the estimated standard deviation.

Figure 8: Government share in extra profits

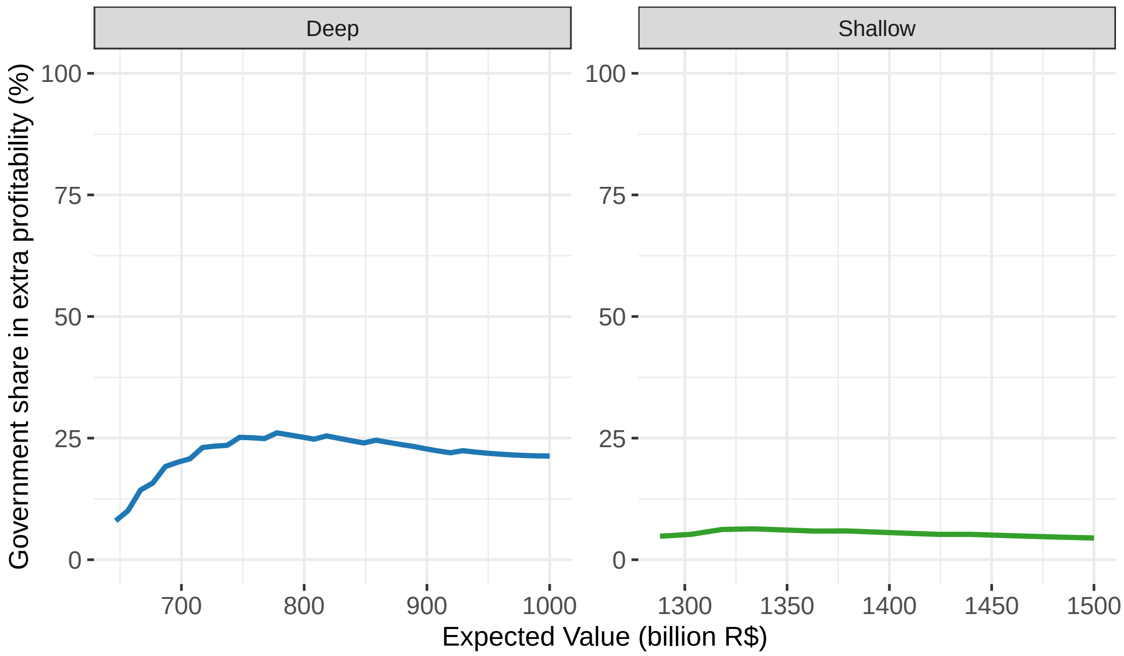


Table 13: Estimation results for different number of potential bidders

# of bidders	σ	$\overline{c}$	$\underline{c}$	c_{part}	Cf. revenue	Relative fit
Onshore						
10	41.05	0.52	0.52	0.51	2.91	3.48
20	76.78	0.58	0.58	0.77	0.28	1.59
30	40.52	0.53	0.53	0.61	0.87	1.24
40	67.15	0.58	0.58	0.83	1.54	1.13
50	84.85	0.75	0.75	2.16	0	1
60	88.11	0.65	0.64	1.14	4.83	1.03
Shallow Waters						
10	172.83	0.97	0.79	1.58	141.69	1.46
20	181.19	0.34	0.34	17.91	0.03	2.39
30	488.7	0.94	0.81	10.91	67.11	1
40	93.01	0.99	0.66	17.4	245.95	2.65
50	102.93	0.99	0.64	17.18	223.87	2.6
Deep Waters						
10	352.78	0.63	0.44	14.51	157.55	1.49
20	369.05	0.59	0.44	14.08	76.89	1.13
30	323.06	0.56	0.49	24.38	17.27	1
40	224.21	0.57	0.43	18.67	35.27	1.07
50	338.68	0.58	0.43	13.16	37.75	1.07
60	390.89	0.59	0.43	17.73	50.17	1.04

Note: values of $sigma$, c_{part} and counterfactual bonus are in billion R\$. $\underline{c}$ and $\overline{c}$ correspond to the proportion of the tract value used to pay for exploration and development of tracts, as well as taxes. Relative fit is the division of the GMM distance by the minimum distance estimated for that location.

In onshore areas we consistently estimate a very low difference between local and foreign cost, and a small counterfactual revenue, as in our main model. However, the other estimates show smaller fixed and variable costs, pointing that these parameters may be inflated, as pointed in our comparison with IBP estimates.

Our estimates for offshore tracts in shallow waters have more noise, with estimates varying more than in onshore areas. Nevertheless, most estimates point to high local costs and a significant level of uncertainty. And, while some estimates show excessive counterfactual revenues, the model fit is significantly worse than our main model.

As for deep waters, our estimates are very consistent, point to a high uncertainty about the tracts' value and a significant difference between local and foreign cost. As the relative fit of the models is not very different, our main model may be underestimating the value of lost government revenue.

5.5 Optimal Weight Matrix

In this section, we present model estimates using an optimal weight matrix in our GMM estimation, instead of using the weights given by the scoring rule, as discussed on section 4.3. Our procedure was to estimate the model iteratively, updating on each round the weight matrix with the inverse of the squared residues of the previous estimation. The results are presented on Table 14.

We experienced some difficulties in the estimation: in shallow waters, the convergence was very fast, but the estimates for the local cost and signal accuracy are clearly inflated. In onshore areas, the estimates for cost are similar to the ones in our main model, but the standard deviation of the signal around the true value is clearly too low. Regarding deep waters, there was no convergence after 50 iterations, so the values presented should be regarded with caution.

Table 14: Estimation results using weights matrix calculated via iterated GMM

Variables	Onshore	Shallow Waters	Deep Waters*
σ	1.83	896.37	24.75
$\overline{c}$	0.43	0.99	0.87
$\underline{c}$	0.42	0.39	0.47
c_{part}	0.23	23.99	2.36
Cf. extra revenue	0.55	725.48	121.44
# bidders	50	30	30
Observations	1106	214	274

Note: values of $sigma$, c_{part} and counterfactual revenue are in billion R$. $\underline{c}$ and $\overline{c}$ correspond to the proportion of the tract value used to pay for exploration and development of tracts, as well as taxes. *There was no convergence for deep water tracts, the parameters presented were obtained after 50 iterations.

5.6 Alternative Model

In this section we present the results using and alternative model, described in Appendix B, for a different number of potential bidders. Although presenting a richer structure, the results are similar to our main model, such that we opted to present it as a robustness test.

As in our main model, we do not find a significant difference between local and foreign costs in onshore areas. As for shallow waters, the estimates remain with much variance, sometimes pointing to a high cost differential and sometimes not. The estimates for counterfactual revenue also vary significantly. On the other hand, in deep-water areas the cost estimates are consistent, showing a significant cost differential and a high amount of lost revenue.

As for our new parameter that represents the exploration costs, c_{exp}, it does not seem to affect the estimation of c_{part}, which remains similar to the values presented in Table 13. However, we can use IBP data to assess whether our estimates for c_{exp} are accurate. In Almeida et al. (2016), they estimate the exploration cost as R$ 1.34 billion, R$ 2.14 billion and R$ 14.4 billion for shallow, deep (post-salt) and deep (pre-salt), respectively[19]. Our estimate for shallow waters is around R$ 1 billion, and R$ 9 billion for deep-water, which is reasonable, given that we do not distinguish between post-salt and pre-salt areas.

[19] There are no comparable estimates for onshore areas.

Table 15: Estimation results with alternative model for different number of potential bidders

# of bidders	σ	$\overline{c}$	$\underline{c}$	c_{part}	c_{exp}	Cf. revenue	Relative fit
Onshore							
10	69.96	0.5	0.5	0.58	0.23	3.15	3.24
20	76.58	0.54	0.54	0.59	0.35	0.87	1.51
30	41.03	0.54	0.53	0.34	0.35	2.58	1.17
40	60.52	0.53	0.52	0.47	0.62	0.62	1.06
50	75.32	0.62	0.6	0.46	1.31	2.19	1
60	43.77	0.54	0.53	0.51	0.39	1.16	1
70	83.23	0.72	0.72	1.64	8.01	0	1.01
Shallow Waters							
10	114.77	0.77	0.4	2.68	1.04	204.17	1.32
20	28.27	0.47	0.46	0.99	0.96	0.19	1
30	750.51	0.73	0.39	25.43	0.96	195.91	1.2
40	836.85	0.99	0.77	2.2	4.8	252.27	1.09
50	480.86	0.35	0.35	29.99	0.44	0.04	1.05
Deep Waters							
10	375.8	0.56	0.43	13.96	8.26	70.74	1.44
20	380.61	0.57	0.43	13.85	9.11	66.72	1.07
30	446	0.67	0.47	9.51	9.9	132.74	1
40	292.87	0.68	0.4	11.26	8.14	95.78	1
50	307.03	0.65	0.45	29.13	9.71	66.47	1.01

Note: values of *sigma*, c_{part}, c_{exp} and counterfactual bonus are in billion R$. $\underline{c}$ and $\overline{c}$ correspond to the proportion of the tract value used to pay for exploration and development of tracts, as well as taxes. Relative distance is the division of the GMM distance by the minimum distance estimated for that location.

6 Conclusions

In this paper, we studied Brazilian oil and gas auctions which were subject to local content requirements. We exploit the use of a multidimensional scoring rule, which includes a local content element, as well as variation of the requirements along the bidding rounds to assess the impact of this policy on auction participation and government revenue.

We show that auctions with increased local content requirements are also the ones with fewer bidders and smaller revenue. We develop a structural auction model within the mineral rights framework that includes endogenous entry and bids in multiple dimensions, including bonus and local content. Due to the lack of an equilibrium characterization in the literature for the scoring formula used in the auctions, we simplify the scoring mechanism using a linearization, which allows us to solve the model. We use production data and decline curves to estimate value distributions based on different locations: onshore, shallow waters and deep waters. We estimate the model primitives, including the accuracy of *ex-ante* information regarding the tracts true value, a general cost level, a differential between local and foreign production costs and a participation cost.

Our estimates show that local costs are 14% higher than abroad in deep water areas, and 16% larger in shallow waters. This accounts for a lost revenue of R$ 17 billion and R$ 67 billion, respectively.

We do not find any significant difference in costs for onshore tracts. When we compare these findings with industry estimates of drilling costs, we see that our model performs well in deep waters and in onshore areas.

For shallow water areas the cost estimates are too high, such that our model predicts that a typical tract with deposits of 150 million boe would be unprofitable. Also, the robustness tests show that the estimates are noisier than in other areas, both for the cost estimates and for the signal variance.

The estimates for deep waters are robust to variations in the number of potential bidders, with counterfactual extra revenue usually exceeding the R$ 17 billion of our main estimate. The same can be seen in the results of an alternative model, which has a richer structure, including the estimate of a exploration cost, but with similar results.

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Appendix A Decline Curve Analysis

The Decline Curve Analysis was first described by Arps (1945), who formalized a technique that was common at the time for forecasting oil output based on the decreasing rate of production. This analysis, first thought to be only empirical, was later shown by Fetkovich et al. (1980) to be also theoretically sound. This work was expanded later in Fetkovich et al. (1987) and Fetkovich et al. (1996).

The main assumption necessary for this approach is that the conditions that affect a well remain constant through the analysis, except for the pressure, that is decreasing due to depletion. During the decline, there is a first stage known as *transient*, in which the boundaries of the reservoir haven't yet been reached, so that the reservoir pressure is constant, and the flow pressure is changing. During this phase, the use of the Arps curves, as the method became known, can lead to unreliable forecasts. The *depletion* stage, with boundary-dominated flow, has constant flow pressure and decreasing reservoir pressure, when it is appropriate to use this technique. Fetkovich et al. (1980) introduced new methods which generate reliable forecasts also in the transient phase, in return of requiring new data which aren't freely available.

A decline curve can have three types: harmonic, exponential and hyperbolic, which generalizes the previous two. The general harmonic equation is the following:

$$q(t) = \frac{q_i}{(1 + bD_i t)^{\frac{1}{b}}}, \tag{19}$$

where q_i is the initial production rate, D_i is the initial decline rate and b is the degree of curvature.

When b = 0, we obtain the exponential decline equation:

$$q(t) = q_i e^{-D_i t}. \tag{20}$$

When b = 1, we have instead the harmonic decline equation:

$$q(t) = \frac{q_i}{1 + D_i t} \tag{21}$$

The results of Arps and Fetkovich show that usually b is between 0 and 0.5, and results near or even above one are associated with wells still in the transient stage. As my initial forecasts using hyperbolic decline found b ¿ 1 in several fields, I opted to be more conservative and use an exponential decline in order to avoid being overly optimistic about the future production of each field. The procedure used in this paper was to select the month in which the tract had the highest production and start the decline analysis from there. As we can see from the Jandaia field in Figures 9, for a field with the theoretical expected behaviour the method works quite well.

However, when analyzing other fields, some issues were found. First, in fields such as Lula the production is still increasing, being impossible to reliably forecast its future production by this method. In this case, the option taken was to make the most conservative forecast: assume that the last production rate was the peak, and use an exponential forecast to assess the future production. The result is in Figure 10. Here and throughout the paper, I will limit the forecast to 30 years (360 months).

The other main issue is that in some fields the production does not behave as nicely as in the previous fields, due to the discovery of new reservoirs, the drilling of new wells, or to the injection of water or gas to expand production, all of which violates the main assumption of the decline curve method. For example, the forecast for the São Pedro field in the Recôncavo basin clearly is not adequate, due to several peaks in production (Figure 11). However, this behavior is more prevalent in old oil fields, and not in the ones that were auctioned since 1999.

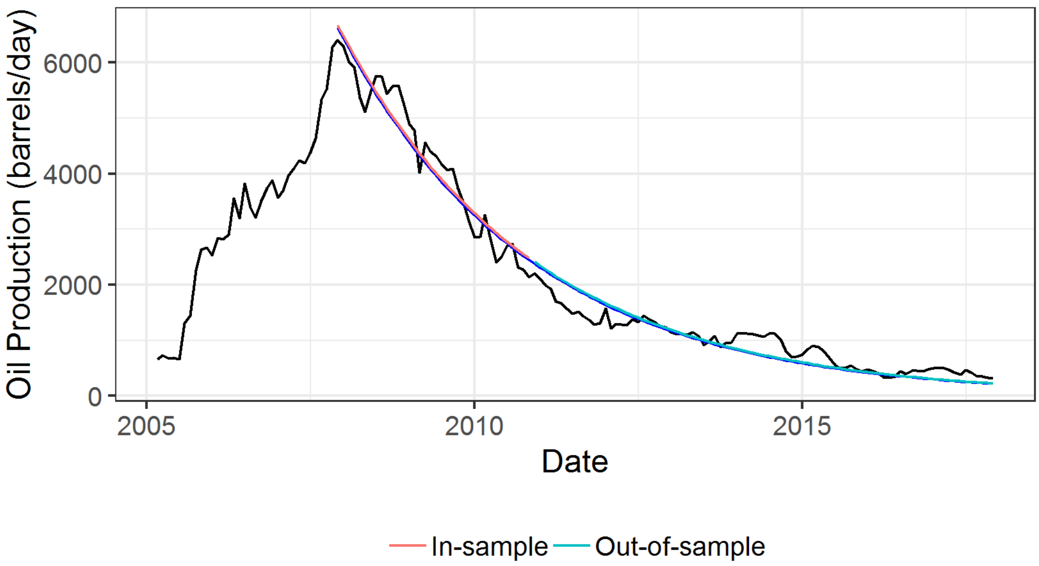

Figure 9: Comparison of the production forecast curve for the Jandaia field using full sample and a selected sample

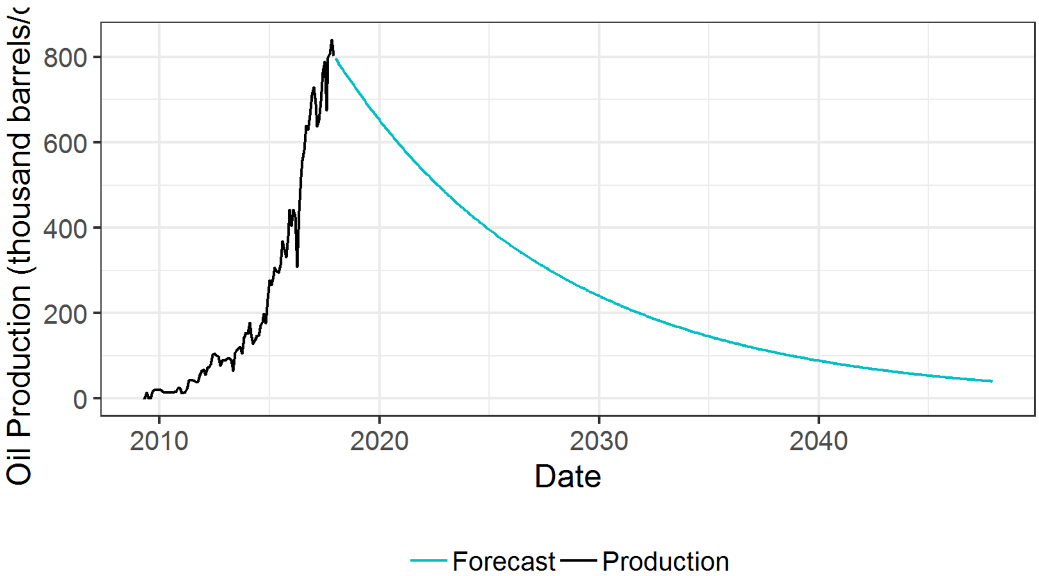

Figure 10: Production forecast curve for the Lula field using the last observation as production peak and the decline rate of Marlim field

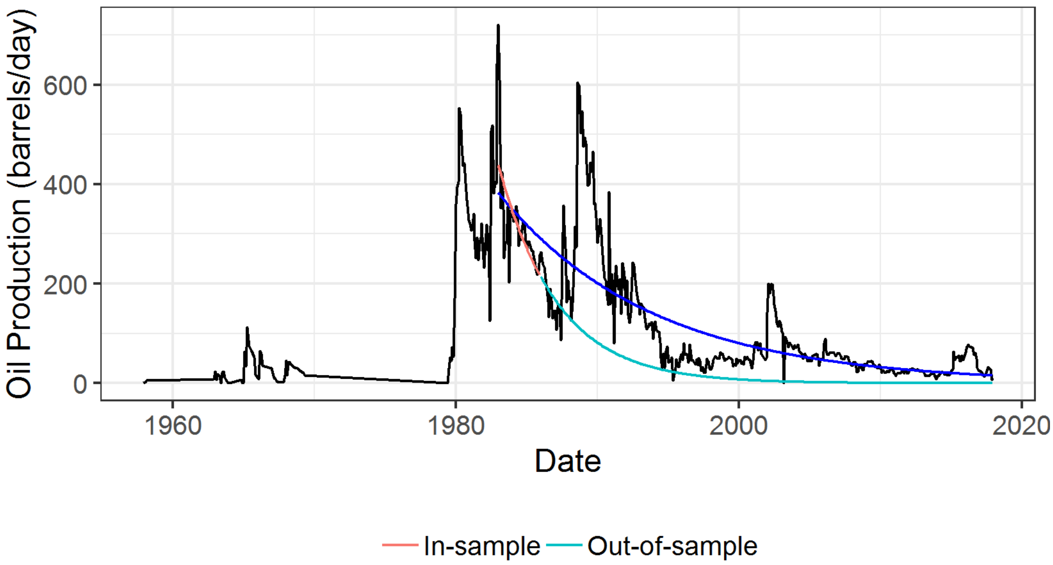

Figure 11: Comparison of production forecast curve for the São Pedro field using full sample and selected sample

Appendix B Alternative Model

Alternatively, we developed a second structure, which we believe to better represent the industry, although at the cost of adding an extra parameter to be estimated. In our main model, *ex-post* profit was given by:

$$\pi = v - \max\left\{p, [\bar{c}\ell + \underline{c}(1-\ell)] \cdot v\right\} - c_{part} - b \tag{22}$$

This structure presents two main drawbacks: the first is that the firm always extracts the true value v from the tract. In reality, we would expect that several fields would not be economical to develop, and as such the operator would prefer to leave the oil beneath the surface. In practice, this feature of the model lower the potential loss faced by the winning companies. Other than that, this framework imposes no bounds on the minimum exploratory program, which can be much larger than observed in reality, given a high enough signal. This happens because we consider that the p bid is sunk when v is high enough.

To deal with this, in this alternative model we consider that v is extracted only when the firm incurs in the local content costs. We also add another fixed cost, c_{exp}, representing the investment in exploration, which will be the upper bound for p. In this structure, the ex-post profit is given by:

$$\pi = \max\left\{-p, v - [\bar{c}\ell + \underline{c}(1-\ell)] \cdot v - c_{exp}\right\} - c_{part} - b \tag{23}$$

This means that, after the auction, the winning firm always pays p, and only then observes v: if it chooses not to produce, its payoff is $\pi = -b - p - c_{part}$. If production is profitable, it develops the tract and obtains $\pi = v - b - c_{exp} - c_{part}$.

Regarding the equilibrium, the main difference is that the second derivative $\frac{\partial^2 V}{\partial p^2} < 0$. That is, when maximizing p we obtain a corner solution, either $p^* = \underline{p}$ or $p^* = c_{exp}$. As such, the solution for the signing bonus b is always given by the usual ODE, as ℓ also always has a corner solution.

As for the identification, there is the extra parameter that reflects the cost of exploration, c_{exp}. We exploit in this structure that the threshold $\underline{v}$ is exactly the minimum value necessary to declare the commerciality of the tract, which is a data we have access to. We can then include a new component to Equation 18, $(\widehat{decl} - decl)$, where $\widehat{decl} = H(\underline{v}|t, t)$.

The results are presented in Table 15.