

## ***The Value Of Extra-Heavy Crude Oil From The Orinoco Belt***

By Bernard Mommer

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### **1. From Orinoco Tar Belt To Orinoco Oil Belt**

Exploration work in the Orinoco Oil Belt (*Faja Petrolifera del Orinoco*) began in 1920 but with disappointing results: the oil discovered was too heavy for commercialization given the available technologies and economic conditions. Exploratory activities resumed in the 1930s when 45 wells were drilled; however, for the same reasons, the area was abandoned once more. At that time, the Belt was in fact known as the Orinoco *Tar Belt* (*Faja Bituminosa del Orinoco*). A third attempt was made in 1956-57, which led to up to 20,000 b/d of heavy oil put into production, and at this point the Orinoco Belt was renamed the Orinoco *Oil Belt* (*Faja Petrolifera del Orinoco*). Contrary to earlier conjectures, explorations revealed that the Belt mainly contained 'heavy' oil – according to the present day nomenclature, 'extra-heavy' – as opposed to a bituminous substance. Finally, in the late 1960s and 1970s the Ministry of Energy and Mines (then *Mines and Hydrocarbons*) conducted an intensive exploration program which involved the drilling of 116 wells.

Following the nationalization of the Venezuelan oil industry, the Ministry of Energy and Mines (MEM) handed over the Orinoco Oil Belt to PDVSA to enable the newly created national company to carry out a more detailed exploratory effort. It was at this juncture that PDVSA divided the 54,000 km<sup>2</sup> area into the four sections that exist today, assigning each to one of its integrated affiliates: Cerro Negro to Lagoven, Hamaca to Meneven, Zuata to Maraven, and Machete to Corpoven. From 1979 to 1983 the company drilled around 662 exploratory wells. At the time PDVSA highlighted the following regarding its findings:

**Table 1**  
**Proven Reserves Of Venezuela**

<b>Year 2001</b>		<b>° API</b>	<b>Billion Barrels</b>	<b>%</b>
Orinoco Oil Belt	Medium	<30 and >= 22	1	0.0
	Heavy	<22 and >= 10	3.227	8.7
	Extra-Heavy	<10	33.796	91.3
	Sub-Total		37.024	100.0
Rest of the Country	Condensates	>=42	1.723	4.2
	Light	<40 and >= 30	10.345	25.4
	Medium	<30 and >= 22	12.889	31.6
	Heavy	<22 and >= 10	14.039	34.4
	Extra-Heavy	<10	1.762	4.3
	Sub-Total		40.759	100.0
Total Proven Reserves	Condensates	>=42	1.723	2.2
	Light	<40 & >= 30	10.345	13.3
	Medium	<30 & >= 22	12.891	16.6
	Heavy	<22 y >= 10	17.266	22.2
	Extra-Heavy	<10	35.558	45.7
	Total		77.783	100.0

“It is important to mention, that, with the exception of a few deposits in the Machete area, the type of crude found in the Orinoco Oil Belt is mobile at reservoir conditions. This permits extraction by conventional methods, at costs that can be compared with those of other heavy-oil oilfields in Venezuela and worldwide.” (Giovanni Fiorillo: *Exploration and Evaluation of the Orinoco Oil Belt*, Petróleos de Venezuela, S.A., Caracas, August 1984).

The volume of oil in the Belt was initially estimated at 1.182 trillion barrels, of which 267bn – that is 22% – would be recoverable. (This figure, to give us an idea of its magnitude, is equal to the proven crude oil reserves of Saudi Arabia). However, the proven reserves, that is reserves that can be recovered using available technologies and under current economic conditions, are of course much smaller. Nevertheless, the Orinoco Oil Belt resource endowment is such that it guarantees Venezuela’s status as one of the most important exporting countries for the foreseeable future.

## 2. Transport Of Extra-Heavy Crude

The Orinoco Belt essentially contains extra-heavy crude: crude oil of less than 10° API (in other words crude that is heavier than water: 10° API is the gravity of water). Although this type of crude oil is liquid at reservoir conditions, above ground, at normal temperature and under atmospheric pressure, it ceases to flow. For this reason it is also classified as ‘non-conventional oil’; conventional oil is flowing both in the reservoirs *and* above ground. There is therefore a problem when it comes to the transportation of extra-heavy crude.

Traditionally, this problem has been approached from two directions. Firstly, the crude can be heated to maintain it in a liquid state to be transported either by pipeline or by ship. In fact, this is the preferred method for transporting very-heavy and extra-heavy oil used for the production of asphalt. Secondly, it can be blended with a diluent, either lighter crude or some by-product such as naphtha or kerosene. For example, 0.618 barrels of 8.5° API extra-heavy crude can be blended with 0.382 barrels of 30° API Mesa crude, resulting in a blend known as 16° API Mery. Of course, if the proportion of Mesa is increased, the outcome is a lighter Mery. These blends can then be sold in the international market in the same way as conventional heavy crude. However, given the size of the Orinoco Belt and the limited availability of light crudes in Venezuela, there were good reasons to look for other solutions to the transport problem posed by extra-heavy oil. This is where Intevep, the research affiliate of PDVSA, comes in.

During the 1980s, Intevep developed a technology whereby the extra-heavy oil was mechanically mixed with water and a surfactant, a chemical, added in order to stabilize the mixture (without this additive the oil and water would of course dissociate immediately). This solution appeared simple enough but implementing it was not so straightforward and took years of scientific and technological research. Therefore, instead of transporting the extra-heavy crude from the Orinoco Belt to overseas refineries, the fourth option of building well-located refineries – or at least some upgrading facilities – within Venezuela itself had to be considered. The upgraded crude could then be sold in the same way as conventional crude. This is in fact what was done with the recent construction of three upgrading facilities in the Orinoco Belt (a fourth one is still under construction). The advantage of this solution was that the extra-heavy crude needed only to be transported by pipeline over relatively short distances, and this could be done with the help of a diluent. Then, at the processing plant, the diluent could be recovered and recycled to the producing fields. Out of the three options for the transport of extra-heavy oil by pipeline: (1) heating it, (2) mixing it with water, or (3) mixing it with a diluent, the latter was economically superior, and therefore it is this option that is more widely used today.

### The Four Extra-Heavy Crude Upgraders In The Orinoco Oil Belt

**Petrozuata:** This Project was authorized by the National Congress in September 1993, with PDVSA holding 49.9% of the equity and Conoco 50.1%. The ‘early production’ began in 1999, and the upgrader began operating in 2001. At full capacity the plant processes 120,000 b/d of extra-heavy crude, which are transformed into 104,000 b/d of upgraded oil (20° API). Investment came to about \$2.2bn.

**Sincor:** This project was authorized by the National Congress in September 1993, with PDVSA holding 38% of the equity, TotalFinaElf 47% and Statoil 15%. The ‘early production’ started in 2001, and the upgrader began op-

erating in 2002. At full capacity the plant processes 160,000 b/d of extra-heavy crude, which are transformed into 144,000 b/d of upgraded oil (32° API). Investment came to around \$2.6bn.

**Ameriven:** This project was authorized by the National Congress in May 1997, with PDVSA holding 30% of the equity, Philips 40% and Texaco 30%. The 'early production' began in 2002, and the upgrader will begin operating in 2004. At full capacity the plant will process 210,000 b/d, which will be transformed into 190,000 b/d of upgraded oil (25° API). The estimated investment is \$3.5bn.

**Cerro Negro:** This project was authorized by the National Congress in June 1997, with PDVSA holding 41.67% of the equity, Exxon-Mobil 41.67% and Veba Oel 16.67%. The 'early production' began in 1999, and the upgrader started operating in 2001. Production of extra-heavy crude, operating at full capacity is 120,000 b/d, which are transformed into 105,000 b/d of upgraded oil (17° API). Investment came to around \$1.8bn.

In total, the four projects altogether will process 610,000 b/d of extra-heavy crude to be converted into 543,000 b/d of upgraded oil with an average of 25° API.

### 3. Orimulsion

Although the original objective of mixing extra-heavy oil with water was to solve a transport problem, Intevep's research revealed that this mixture could actually be used as a fuel in power stations. For this objective, the optimal mix was 70% extra-heavy crude with 30% water, and 1% surfactant in order to stabilize the emulsion. This mixture was given the name *Orimulsion*. However, burning extra-heavy crude directly without refining it at least to some degree generates gases and ashes which are very polluting. Again, following years of research, Intevep produced suitable solutions to the problems of, firstly, how to filter and clean these gases in order to comply with environmental regulations in the consuming countries and, secondly, how to dispose of the ashes. Thus, what began as a research into a transport problem, ended up with the discovery and development of a new boiler fuel. However, the accumulated research and development costs into this problem, up to 1994, amounted to around \$1.00bn.

But was this new fuel competitive compared with the traditional heavy fuel oil that was being consumed in power stations for the same purpose? The answer is no, on three accounts. In the first place, the heavy fuel oil is also known as residual fuel oil because it is what is left after extracting all the lighter components from a barrel of oil. In fact, most complex and modern refineries are designed to minimize this residue, with refining costs being covered by the lighter products. By contrast, the production costs of Orimulsion are significant, at about \$2.00/B of extra-heavy crude. Secondly, each barrel of extra-heavy crude is converted into 1.42 barrels of Orimulsion following the addition of water, and this causes transport costs to increase proportionally. Thirdly, in order to burn Orimulsion, costly additional installations and filters are needed just to equal the performance of heavy fuel oil in environmental terms. Finally, Orimulsion cannot begin to compete with natural gas, the cleanest fuel of all, on environmental grounds, or with coal on economic grounds. With the emergence of combined-cycle power plants, burning gas became much more efficient and many power stations opted in favor of it despite its somewhat higher costs compared with heavy fuel oil. Coal, for its part, is certainly the most polluting of all fuels but it is also by far the cheapest. The problems facing Orimulsion did not, however, end here.

#### 3.1 The Return Of The *Tar Belt*

Following the second explosion of oil prices in the 1970s, due to the Iranian revolution and the subsequent war between Iraq and Iran, the consuming countries associated in the International Energy Agency (IEA) agreed to reduce the consumption of heavy fuel oil in the generation of electricity systematically. The IEA recommended that heavy oil be substituted for coal (and, years later, also for natural gas), and that the consumption of heavy fuel oil be restricted, as far as possible, to the demand for electricity during peak hours. In this scheme there appeared to be no room for Orimulsion.

The consumption of oil was to be limited in so far as possible to the transportation sector, where its substitution was impossible. These recommendations were in fact an attempt to minimize the market for crude oil coming from OPEC member countries, and the IEA simultaneously implemented a policy to stimulate non-OPEC pro-

duction. Moreover, the IEA policies also targeted the exporting countries themselves, looking for ways and means to soften, weaken and undermine those countries' national oil policies which, basically, consisted in maximizing the value of their natural resources. By contrast, the consuming countries were interested in minimizing that value. These policies are easy enough to comprehend; what is not easy to comprehend, however, is why the IEA's position could be shared by a national company like PDVSA.

The principal reason why Venezuela's oil reserves were nationalized in the first place was because international oil companies had been systematically aligning themselves with the economic interests of the consuming countries, against those of the exporting countries in their capacity as natural resource owners. The national companies' interests on the other hand, were supposed to be aligned with those of the nation. PDVSA's desertion of the national cause, however, was already a fact in the 1980s. Generally speaking though, the situation was not yet as extreme as it would be in the 1990s. As regards Orimulsion, however, the situation was already unequivocal.

When PDVSA – or to be more precise Lagoven, the biggest of PDVSA's subsidiaries at that time – took over Intevep's 'Orimulsion Project' in the mid 1980s, the company initiated a public relations campaign to rename the Orinoco *Oil Belt* (Faja *Petrolífera* del Orinoco) the Orinoco *Tar Belt* (Faja *Bituminosa* del Orinoco). This change of name, however, was only one element of a larger 'package'.

At this point, and in order to understand fully the subsequent issues, it is important to step aside for a moment in order to clarify the extra-heavy crude/natural bitumen distinction and discuss its implication in more depth. The difference between extra-heavy crude and natural bitumen lies in the simple fact that extra-heavy crude is a liquid whereas natural bitumen is not: *there is no chemical difference between them*. Nevertheless, as far as production techniques and production costs are concerned, the difference between a solid and a liquid is of fundamental importance. Natural bitumen is far more costly to produce than extra-heavy crude because it either has to be mined, or heat has to be injected into the reservoir to convert it into a liquid (with results in upward of one barrel of oil being consumed for every three barrels produced to generate heat). Around 90% of extra-heavy crude in the world is located in one reservoir: in the Orinoco Oil Belt; and 90% of natural bitumen in the world is located in the Tar Sands of Athabasca, in the Canadian Province of Alberta. The difference between the two locations is simply their temperature: the average temperature of the reservoirs in the Orinoco Belt is around 53°C, whereas in the Athabasca Sands it is barely 11°C. In short, it's hot in Venezuela and cold in Canada and this affects the state of the natural resource and its classification as extra-heavy crude or natural bitumen respectively. This point being made, we can now go back to the public relations exercise in rebranding.

The decision to rename the Belt was already in place in 1988 when a PDVSA affiliate specifically dedicated to the production and marketing of Orimulsion was set up. This new affiliate was christened Bitor, *Bitúmenes del Orinoco* (a 100% affiliate of PDVSA), with this name revealing the implicit intention to minimize the value of the natural resource in question. In effect, PDVSA/Bitor had decided to go ahead with the new fuel, whose competitiveness would be guaranteed by selling it at the price of coal signing long-term supply contracts (up to 20 years). Moreover, the Venezuelan Government would be persuaded that the natural bitumen being turned into Orimulsion was not part of the country's OPEC quota in the same way as, for example, the coal from Guasare (a Venezuelan coal mine) was not. At the same time, PDVSA/Bitor was also trying to reach an agreement with the consuming countries to ensure that they accepted Orimulsion as a 'liquid coal', and thereby excluded it from their restrictive policies against OPEC. In 1996 the World Customs Organization in Brussels duly classified Orimulsion as natural bitumen. Immediately thereafter, the IEA recommended that it be used in the generation of power together with coal and natural gas.

But how was it that the Venezuelan Government was convinced of a strategy which essentially consisted of selling oil at the price of coal? PDVSA's public relations campaign was based on two arguments. First, the company informed the Venezuelan politicians and the public in general that Orimulsion would only compete with coal, that is, it would only displace coal in the generation of electricity and not heavy fuel oil. Consequently, it would have no effect whatsoever on oil prices, and therefore, from this point of view, it would not affect the national policy of maximizing the value of Venezuela's hydrocarbon resources. However, the problem with this assertion is that in the overwhelming majority of cases, Orimulsion displaced heavy fuel oil, in some isolated cases natural

gas, but very rarely, if ever, coal. So, to take a very recent example, in May of 2003, Bitor informed the country that the contract it was to sign with Coleson Cove Station in New Brunswick, Canada, would displace coal with Orimulsion. This station burned nothing but heavy fuel oil, however, a fact easily verified on the Internet. Hence, not only was oil being sold at the price of coal, but the price of oil (sold as oil) was also being undermined. Even worse, Venezuela, with around 250,000 b/d, is a very important exporter of heavy fuel oil!

PDVSA also told Venezuelan politicians and the public in general that Orimulsion was made from natural bitumen, and that this substance was different from extra-heavy crude oil and had no other possible use than that of being transformed into Orimulsion. Indeed, at the same time the World Customs Organization actually classified Orimulsion as natural bitumen, PDVSA took formal steps and exercised pressure in an informal way within both the government and in the National Congress, to change the official name of the Orinoco Belt. On their websites PDVSA/Bitor at that time was already presenting the Orinoco Belt to the world as the Orinoco *Tar Belt* (*Faja Bituminosa del Orinoco*). This had partial success even within the Ministry of Energy and Mines (MEM): in 1996 Bitor's reserves of extra-heavy crude were reclassified as natural bitumen despite the fact that beyond the area belonging to Bitor, the reserves of extra-heavy crude were maintained as such. However, and contradictorily, at the same time the MEM started to publish in its annual publication *Oil and Other Statistical Data (Petróleo y otros datos estadísticos)* an official definition of natural bitumen – that of not being a liquid in its original state within the reservoir – which contradicted Bitor's reclassification.

That same year PDVSA/Bitor had a major political success when the National Congress approved Bitor's first joint venture in Orimulsion with foreign investors. In the 'Exposition of Motives', published in the country's *Gaceta Oficial*, the National Congress stated that: "there are substantial proven reserves of natural bitumen in the Orinoco Belt."

Moreover, in one of the clauses of the 'Framework of Conditions' (*Marco de Condiciones*) it was established that: "given that official international customs organizations have classified Orimulsion as a non-oil hydrocarbon, the levels of natural bitumen being produced to be processed into Orimulsion by the Association will not be subject to the international commitments of the Venezuelan Republic arising from its participation in international organizations."

And, with the obvious intention of overwriting MEM's official definition of natural bitumen, another clause established that: "in the Association Agreement to be concluded, the parameters for defining natural bitumen will have to be established."

In other words, the National Congress authorized a joint venture between Bitor and foreign investors, the apparent objective of which was to exploit reserves of 'natural bitumen'. However, it was left to the associates to define what actually constituted 'natural bitumen'! But just in case, in the first clause of the 'Framework of Conditions' (*Marco de Condiciones*), the Association made sure they had the right to: "exploit the reserves of natural bitumen and its associated fluids..."

In other words, they were given the right to produce whatever liquid they might find there.

Nevertheless, this association never bore any fruit. It was supposed to supply a power station in Florida, *Florida Power & Light*, but as it happened the government in that state withheld the necessary environmental permits. Orimulsion is certainly cleaner than coal, yet the fact was that *Florida Power & Light* was not burning coal but heavy fuel oil, and Orimulsion has no environmental advantage over heavy fuel oil.

Five years later, in December 2001, the National Assembly approved Bitor's second joint venture with foreign investors, this time with a Chinese company. The text they approved contains the same lines quoted above, and natural bitumen is defined in the Association Agreement in such way that the decisive point, whether or not the substance flows, is determined by its state above ground. Above ground extra-heavy crude is definitely not flowing.

PDVSA/Bitor's lobbying was also successful regarding the new Organic Law of Hydrocarbons, approved in December 2001. Under certain economic conditions, this law in its Article 44 allows the basic royalty rate of 30% for extra-heavy crude to be reduced to 20%. In the case of natural bitumen, however, the royalty rate can be reduced even further to 16 2/3%. Confusion in the majority of cases, and complicity in other cases, had by now permeated all levels of government.

The truth is that Bitor, *Bitúmenes del Orinoco*, never produced a barrel of natural bitumen. What Bitor produces, like the upgrading companies, is extra-heavy crude. Anyway, above ground, once the barrel is produced, this distinction is irrelevant. The hydrocarbon, whether it is termed natural bitumen or extra-heavy crude, has three possible uses: firstly, it can be blended with lighter crudes or products and sold as a component of a blend, a practice which has been going on for decades; secondly, since the 1990s, it can be processed into Orimulsion; and, thirdly, following the completion of the first upgrading plants in 2001, it can be converted into upgraded crude oil.

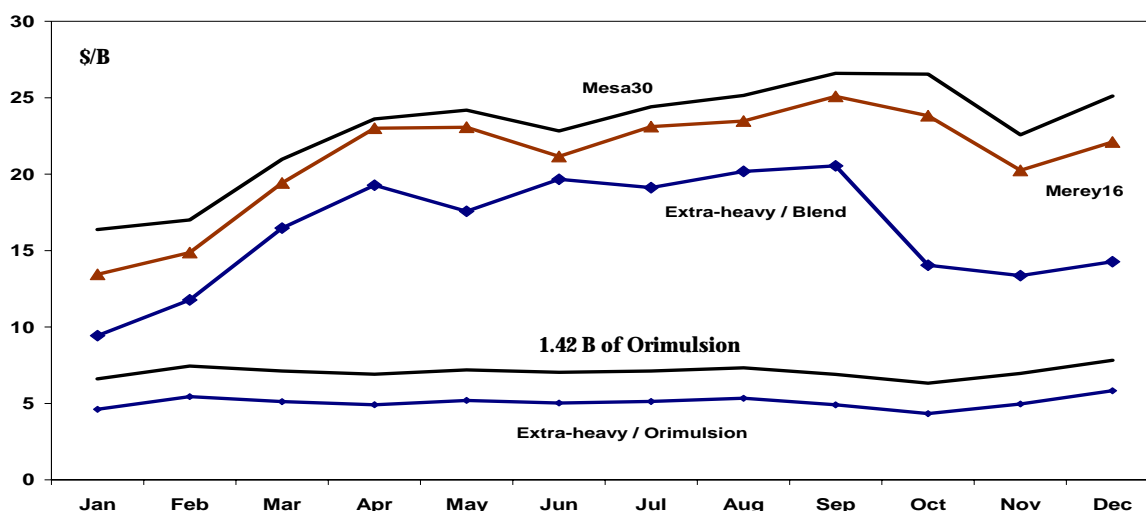
#### 4. The Value Of Extra-Heavy Crude: Prices

The price of extra-heavy crude, as a component of a blend, is determined by the market. Let's take Merey as an example, this blend which, as already stated, consists of 61.8% extra-heavy crude and 38.2% Mesa. Now, both Mesa and Merey have a market price, as they are traded internationally. Hence, the market value of extra-heavy crude can be easily calculated using the 'rule of three'. Then, following some adjustments to take transport costs into account, one can calculate the price fob Venezuela and finally also the wellhead price.

To exemplify: in 2002, the average market prices of a barrel of Mesa and Merey were \$22.95 and \$21.07, respectively. After taking into account the adjustments mentioned above, the market value of a barrel of extra-heavy crude, free on board (fob) Venezuela, was \$16.31/B. By contrast, Bitor produced around 70,000 b/d of extra-heavy crude which was then transformed into 100,000 b/d of Orimulsion. The market value of 1.42 barrels of Orimulsion – which contain one barrel of extra-heavy crude – averaged, that same year, \$7.07. One can conservatively estimate processing costs to be \$2.00/B, the net-back price per barrel of extra-heavy crude converted into Orimulsion was \$5.07 (Graph 1). The difference is astonishing, \$11.25/B! The opportunity costs for this year add up to a total of \$290mn!

**Graph 1**

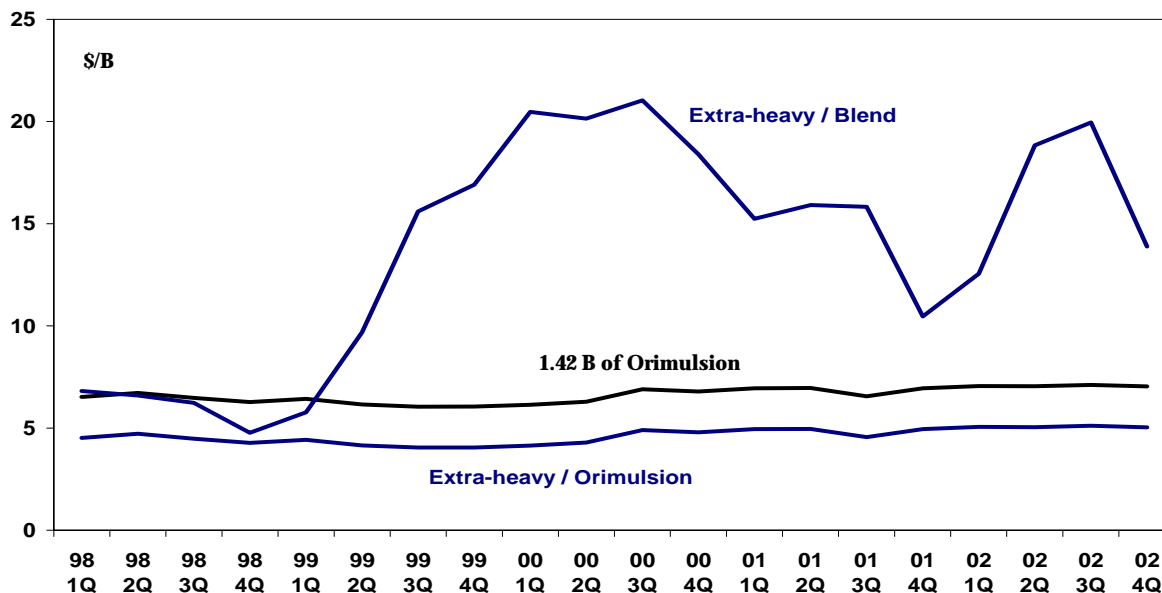
**The Value Of Extra-Heavy Crude: Blends Vs Orimulsion, 2002**



Granted, 2002 was an exceptionally good year for blends. For this reason, Graph 2 presents the quarterly data for the five-year period from 1998 to 2002, a period which covers both depression and boom years. As is evident, it is only in 4Q 1998 that the market value of extra-heavy crude came down anywhere near to the netback price of Orimulsion, and this was during the worst quarter of the worst year in the history of oil prices since WW II! On

average, the blended extra-heavy crude was sold at \$13.76/B. If used for Orimulsion, however, the same barrel was only worth \$4.63/B. The difference is still enormous: \$9.13/B!

**Graph 2**  
**The Value Of Extra-Heavy Crude Blends Vs Orimulsion, 1998-2002**



The outcome is logical. In the long term, there is a floor and a ceiling to oil prices, which are both related to coal. The floor is given by oil competing against coal in the generation of electricity and the ceiling, by coal competing against oil in transport: that is to say when petrol produced from coal can compete with that produced from oil. As the market has been telling us for decades, none of these two extremes is sustainable; the first, because of supply restraints, and the second because of demand restraints. It is for this reason that in the long run, oil prices fluctuate between these two extremes. However, exporting countries, and OPEC in particular, try to ensure that these prices remain within a much narrower band (in fact, the established band currently goes from \$22-28/B for the OPEC basket). The 'Orimulsion Project', by contrast, is inherently anti-OPEC and, more generally, hostile to all exporting countries, pegging the price of oil, through the price of extra-heavy crude, to the price of coal.

At any rate, the inevitable question arises: why upgrade if the simple blending of extra-heavy crude generates a better economic outcome? Before answering this question, however, it is convenient to look at the fiscal regimes that relate to each case.

## 5. The Value Of Extra-Heavy Crude: The Fiscal Regimes

We will limit the scope of this discussion to the fiscal regimes in place in 2002 – which are still the same in 2003 – as defined by the Organic Law of Hydrocarbons, the Income Tax Law, and by the association agreements. Moreover, we will focus our attention on the two fundamental parameters: royalties, on the one hand, and income tax, on the other.

### 5.1 Royalties

According to the new Organic Law of Liquid Hydrocarbons, the royalty rate applicable to PDVSA's 100%-owned affiliates is 30%, with the sole exception of Bitor. A rate of 16 2/3% applied to this affiliate in 2002, on the assumption that it processed natural bitumen. Moreover, while PDVSA paid royalties based on the market value of royalty oil, Bitor succeeded, in 1996, in negotiating a special agreement with the MEM which did not even reflect the netback price as calculated above. This agreement was based on a fancy formula according to which a barrel of extra-heavy crude had a minimum price of \$0.682/B, and a maximum of \$10.00/B: this minimum corre-

sponded to what had been established by the 1943 Hydrocarbons Law, but the existence of a maximum, however, was an unprecedented innovation. Why should the owner of a natural resource not benefit from the increase of prices beyond \$10.00/B? The fact of the matter is that in 2002 this formula generated an average 'market value' of \$1.28 (sic!) for a barrel of extra-heavy crude and consequently, Bitor paid royalties of \$0.21/B (at the rate of one-sixth). By contrast, PDVSA paid \$4.89/B in royalties, based on a \$16.31 price per barrel of extra-heavy crude used for blending.

Meanwhile, the upgrading companies in the Orinoco Belt, whose contracts are based on the old Law of Hydrocarbons, pay a royalty of one-sixth on their 'early production' (Ameriven, and Sincor until March 2002), and a royalty of only 1% once the upgraders begin work (Petrozuata, Cerro Negro, and Sincor since April 2002). This 1% rate, in accordance with the contracts, applies for the first nine years of upgrading; thereafter, they will have to pay the rate of one-sixth: the customary rate in accordance with the old Law of Hydrocarbons. As regards prices, however, royalties are paid in accordance with the rules established under PDVSA's royalty agreements, that is, based on the market value of the extra-heavy crude. In sum, therefore, these associations pay royalties of \$2.72/B for their 'early production', but only \$0.16/B once they have begun to upgrade the crude (Table 2).

**Table 2**  
**Fiscal Regimes For Extra-Heavy Crude, 2002**

Royalty (\$/B)	PDVSA		Upgraders (Example)	
	Blends	Orimulsion	Early Production	Upgrading to 30° API
Price of Royalty Oil	16.31	1.28	16.31	16.31
<i>Royalty Rate</i>	30%	16 2/3%	16 2/3%	1%
Royalty	4.89	0.21	2.72	0.16
<b>Income Tax</b>				
Market Price of Extra-Heavy Crude / Product	16.31	7.07	16.31	22.95
Processing Costs	0.00	2.00	0.00	9.00
Market Price of Extra-Heavy Crude / <i>Netback</i>	16.31	5.07	16.31	13.95
Production Costs	3.60	3.60	3.60	3.60
Earnings before				
Income Tax	7.82	1.26	9.99	10.19
<i>Income Tax Rate</i>	50%	34%	34%	34%
Income Tax	3.91	0.43	3.40	3.46
<b>Net Income</b>	3.91	0.83	6.59	6.72
<b>Fiscal Take</b>	8.80	0.64	6.12	3.63

## 5.2 Income Tax

Regarding income taxes, in the cases of Orimulsion and upgraded oil, we have to start from netback prices, based on processing cost estimates of \$2.00/B and \$9.00/B, respectively. The cost to produce a barrel of extra-heavy crude may be estimated at \$3.60, and from there we can ascertain the profit per barrel of extra-heavy crude before income tax. In the case of PDVSA, the applicable rate is generally 50%, again with the exception of Bitor. To Bitor and the upgrading associations the non-oil income tax rate of 34% applies. As can be seen in Table 2, in the case of PDVSA, the income tax varies from \$3.91/B (blend) to \$0.43/B (Orimulsion). In our example, the upgrading associations, on the other hand, would pay \$3.40/B ('early production') and \$3.46/B (upgrading). Consequently, the total fiscal take, the sum of royalties and income taxes varies, in the case of PDVSA, from \$8.80/B (blend) to \$0.64/B (Orimulsion), while in the case of the associations, it varies from \$6.12/B (early production) to \$3.63/B (upgrading).



## 6. Conclusions

When looking at the value of extra-heavy crude from the Orinoco Oil Belt, one is confronted with two extremes: blending and the production of Orimulsion. With blending, the barrel of extra-heavy crude fetches full market price and the owner of the natural resource (if produced by PDVSA itself) collects a big portion of the income thanks to royalties and income taxes. This is in line with traditional policies which can be observed practically in all exporting countries and even in the oil-producing provinces or states of the consuming countries with federal structures, such as Canada and the United States (ie Alberta or Alaska). All of these have traditionally asserted and enforced their rights as national or regional proprietors of a non-renewable, exhaustible, and relatively scarce natural resource. In each of them there prevails what can be termed a proprietorial regime in oil.

As far as Orimulsion is concerned, however, no value is attached to the extra-heavy crude. Not only is it made to compete with coal by reducing its price to a minimal level, but only the interests of investors are taken into account. Thus, the fiscal regime is used as a wild card to make the investment profitable, royalties being reduced to negligible levels and income tax rates to levels associated with non-oil income. Such a policy can only make sense within *consuming* countries, because in these countries the consumers and proprietors of the natural resource are one and the same. Hence, if these people do not benefit directly from the ownership of the natural resource, they still benefit indirectly as consumers, in what is effectively a zero-sum game. When it comes to exports, and even inter-regional trade, however, the situation is entirely different.

Throughout the 1990s (and even earlier), the PDVSA leadership decided to impose oil policies on Venezuela, an exporting country, that were designed by the consuming countries; that is to say, the *national* oil company pursued and implemented a non-proprietorial regime. This policy was both profoundly illegitimate and anti-national, so it had to be surrounded by thick clouds of misinformation (to put it mildly) as well as outright lies. The classification of extra-heavy crude as natural bitumen was one such cloud. Dispersing these clouds was the only obstacle to classifying the raw material in question as either extra-heavy crude, or natural bitumen. Objectively speaking, it should have been in fact no more difficult than classifying H<sub>2</sub>O as either a solid, liquid, or gas. Yet clearing those clouds only became a possibility after the 'cloud-producing' leadership lost its hold over PDVSA. And this only happened when they threw themselves into a desperate strike in December/January 2002-03.

The upgraders in the Orinoco Belt represent a more complicated case, but, still, not a fundamentally different one. Their fiscal design corresponds essentially to a non-proprietorial regime in as much as it was used as a wild card to make the investment profitable without taking into account the interests of the natural resource owner. Thus, the latter gave up \$2.68 (the difference between \$8.80/B and \$6.12/B) income per barrel in 'early production', and with upgrading the fiscal sacrifice went up to \$5.17/B (the difference between \$8.80 and \$3.63). The total fiscal opportunity cost, for the year 2002, therefore, amounted to over \$600mn. All this, of course, was in accordance with the IEA policy of eliminating any proprietorial fiscal regime which would inevitably slow down the flow of investment. This slowing down, though, works in the same way, and for the same reason, as the investors' profits do. Indeed, the situation is completely symmetrical: just as an investor will never rush to invest without the prospect of getting a reasonable return (let us say an internal rate of return of 15%), so the owner of the natural resource should never allow an investment to be made without the prospect of gathering a customary ground-rent (in Venezuela's case a royalty of one sixth, according to the old Law of Hydrocarbons, for example, or one fifth minimum, according to the new Organic Law of Hydrocarbons).

The non-proprietorial orientation of the upgraders can also be viewed from a different perspective. In fact, if the extra-heavy crude was, natural bitumen as alleged and as such allegedly exempt from OPEC quota in the same way as Venezuelan Guasare coal, the upgraded oil would then also be exempt from the quotas since OPEC only regulates crude oil production. And there are no two ways about it; upgraded oil is a refined product. In fact, since the production of upgraded oil began, the IEA has classified it as a synthetic crude oil, something which, by definition, is produced from natural bitumen. The natural bitumen used to produce upgraded crude is therefore excluded from the IEA figures on Venezuelan crude oil production, and so, in this way, the message is conveyed – very explicitly – that Venezuela's production is very much below quota and that the country *should* increase production.

On the other hand, however, the upgraders aim to add value to the extra-heavy crude by transforming it into lighter products. From this point of view they are of strategic value to the country. Certainly the fiscal sacrifice is high: adding up the output of the four associations gives a figure of 610,000 b/d of extra-heavy oil which is transformed into 543,000 b/d of upgraded crude. But still, because of the high realization price, even with a 1% royalty and the usual non-oil income tax rate, the 2002 fiscal take per barrel was five times that of Orimulsion. Moreover, looking ahead, the development of productivity (as a result of 'learning by doing') in the production and upgrading of extra-heavy crude oil, leads one to hope that, in not too distant a future, Venezuela can reasonably expect to realize a netback value per barrel of upgraded crude close to the current value of blended extra-heavy crude. This is not true in the case of Orimulsion, though, because the price of the extra-heavy crude used to produce it is subject to a very low ceiling as a result of its link with coal.

This is also the opportunity to make clear why a policy of simply blending the extra-heavy crude is not possible. The reason is that the blend enters a very limited market of refineries with deep conversion capacity. If this capacity is exceeded, the price of extra-heavy crude would collapse. Hence, Venezuela has to ensure that this capacity exists and expands progressively and continuously. Nevertheless, having upgraders in Venezuela as completely new grass-root refineries, in an environment lacking almost any infrastructure, was a very costly solution. It would therefore have been advisable to act cautiously and even wait if need be. At the time the upgrading projects started, however, PDVSA's leaders wanted to proceed as quickly as possible and with a great volume of production, following a strategy which sought to undermine the traditional proprietorial oil policy, and thus force Venezuela to leave OPEC. Indeed, in this set-up, the barrels subject to OPEC quotas would be those with the highest fiscal take, whereas those with the lowest fiscal take would always remain on the market, and as a result, any cut in production would become more and more painful to the country.

## 7. Perspectives

At present, PDVSA and its 100%-owned affiliates are producing about 200,000 b/d of extra-heavy crude oil for blending; Bitor produces around 75,000 b/d; and the upgraders are about to reach 610,000 b/d, as planned. In addition, the association Sinovensa will contribute with another 105,000 b/d by the end of next year. Thus, before long Venezuela will be producing about one 1mn b/d of extra-heavy crude. Note that this is the worst quality crude oil produced, and that it is the type of crude of which the country has the largest reserves. Thus the fiscal income that this crude generates should represent a floor, whereas all the other crudes should always generate a greater income. There is simply no reason to produce a conventional barrel of crude oil which would generate lower fiscal revenues. However, PDVSA's past leadership was determined to lower this floor to zero, and ultimately to lower fiscal revenues generally. And in the 1990s they did so very effectively, with disastrous consequences for the Venezuelan economy. In contrast with this situation, a national strategy to increase the value of the natural resource has to be based on raising this fiscal floor to the highest feasible level. Hence, the new Organic Law of Hydrocarbons, after evaluating those projects, defined a royalty rate of 20% as the minimum for extra-heavy crude oil (although the usual royalty rate was set at 30%). In terms of income tax, the problem is how to prevent the upstream income being diluted through integration with the downstream, be it by lowering transfer prices, by outsourcing, or by importing transport and refining costs, as has been happening with PDVSA in general and with the upgraders in the Orinoco Belt in particular. This is the reason why the new Organic Law of Hydrocarbons demands that investors keep their accounts for upstream and downstream activities separate: income tax is therefore also assessed separately. By simply implementing these two measures, the fiscal take per barrel of upgraded extra-heavy oil, during 2002 would have gone up from \$3.63/B to \$6.47/B. But because Orimulsion can have no place in such a value maximisation policy, the government decided in May 2002 to phase out its production. Of course, existing contractual commitments will be honored as has always been the case in Venezuela.

The recovery of fiscal revenue which presupposes the alignment of project economics with the real market value of the natural resource is going to take some time. Simply to reverse the trend of a decreasing fiscal take per barrel will not be easy, precisely because it is at that point that the four upgraders (with their low fiscal take) are becoming fully operational. But at least it will be possible to slow down this downward trend through a system of more vigorous fiscal controls. On the plus side, the new Organic Law of Hydrocarbons with its 30% royalty rate

is already being applied to PDVSA and Bitor will have to pay at least a rate of 20% based on the market value of the extra-heavy crude. Finally, this new Law will without exception also apply to all new projects involving private investors.

### **Dismantling The Fiscal Regime**

PDVSA started dismantling the Venezuelan fiscal regime in oil since the 1980s. However, it was only in the 1990s that the company had out and out success in this endeavor. Thus, in 1990 PDVSA started consolidating its accounts in Venezuela with Citgo in the US, which resulted in increasing pre-tax costs in Venezuela. Then, in 1993, taking advantage of the political trouble of that year – the impeachment of President Carlos Andrés Pérez – PDVSA imposed almost at will its fiscal agenda on the Government and the National Congress. The so-called Fiscal Export Value, an export tax of similar importance as the then one-sixth royalty, was scrapped. At the same time, the Income Tax Law was reformed and PDVSA was given a wide berth to minimize fiscal liabilities under that Law. This explains the major part of the collapse of fiscal oil revenues from 1993 onwards. In effect, between 1976 and 1992, 66 cents of every dollar produced by the oil industry went to the Treasury; between 1993 and 2001, this average decreased to 45 cents (and this percentage also included dividend payments). Compared with the previous period, the Government lost \$3.4bn annually, which largely explains Venezuela's economic misery during the past decade. And this loss does not include the opportunity costs and value destruction of Orimulsion and the Internationalization Program. With regard to the latter, fiscal revenue suffered another loss, an average of \$500mn for the years 1998 to 2002, due to PDVSA's practice of transfer pricing: selling to its affiliates abroad at prices significantly below fair market value.

In an effort to recover the fiscal regime, the new Organic Law of Hydrocarbons raised the royalty rate to 30% and introduced separate accounts for upstream and the downstream activities. In March 2003, the Interministerial Committee for the Coordination and Joint Examination of Issues Relating to the Fiscal Regime for Hydrocarbons (a body made up of the Ministry of Energy and Mines (MEM), the Ministry of Finance and the Central Bank of Venezuela) was created. This body is now implementing the mechanisms and necessary controls to prevent similar transfer pricing from arising again in the future. Furthermore, the Committee is also considering the necessary reforms to 'ring-fence' the highly profitable upstream, and thereby put an end to the abusive practice of minimizing income tax liabilities in which PDVSA and private investors have engaged.