

## CASE 5

# The BP Amoco-ARCO Merger: Alaskan Crude Oil (2000)

Jeremy Bulow and  
Carl Shapiro

### INTRODUCTION

---

In March 1999 British Petroleum Amoco (BP) announced its intention to acquire the Atlantic Richfield Company (ARCO) for \$25.6 billion in stock. As one of the largest oil mergers ever, the BP/ARCO deal was sure to attract intense public attention as well as antitrust scrutiny. Attention was further heightened because the deal was part of a more general consolidation in the unloved oil industry. In particular, the BP-ARCO deal came close on the heels of the massive 1997 Shell-Texaco joint venture, BP's December 1998 acquisition of Amoco, and the then-pending Exxon-Mobil merger.

At the heart of the BP-ARCO deal was the combination of the firms' Alaska North Slope (ANS) crude oil reserves and related operations. The huge Prudhoe Bay oil field was the only one in the United States to have two operators. By 1999, with production having fallen by more than one-half since its 1988 peak, it had become far more efficient to have just one operator. Furthermore, the three primary owners of ANS—BP, ARCO, and Exxon—had disparate shares of oil and gas production. Exxon, for example, owned a larger share of the gas than the oil. This conflict made it more difficult for the partners to agree on an efficient development strategy.

---

Bulow served as the Director of the Bureau of Economics at the Federal Trade Commission at the time that the Commission reviewed the BP-ARCO merger. Shapiro served as a consultant and expert witness on behalf of BP and ARCO in the antitrust review and litigation of their merger. The opinions expressed here are an amalgam of the sometimes distinct views held by the two authors, and should not be attributed to the Federal Trade Commission, individual commissioners, or to BP or ARCO. We thank Simon Board, John Hayes, Paul Klemperer, and the editors for helpful comments on an earlier draft.

## Case 5: The BP Amoco-ARCO Merger (2000)

Overall, BP estimated it could save \$100–200 million per year from reorganizing Prudhoe.<sup>1</sup> But the consolidation raised antitrust concerns. Exxon and some smaller investors were minority shareholders in the fields but did not operate in Alaska. Thus, the combined BP-ARCO would own 74 percent of ANS production and would operate every oil field in the state.

BP entered the antitrust review process with considerable optimism. From its perspective, the deal was quite “clean” on antitrust grounds. Downstream, BP had no West Coast refining and marketing assets, so the merger would not affect concentration there. Upstream, the overlap was in the production of crude oil, arguably a world market where the combined share of BP and ARCO was quite small. But BP also recognized that there were various upstream overlaps related to the exploration, production, and transportation of ANS.

The Federal Trade Commission (FTC), along with the states of California, Oregon, and Washington, was keenly interested in how the merger would affect the buyers of ANS, namely West Coast refineries, as well as final consumers, such as motorists. While the commission typically evaluates deals based on the effect on consumer welfare alone, as opposed to the sum of consumer and producer welfare, it presumed that an increase in prices charged to refineries would be largely passed along to final consumers. The state of Alaska had considerable interest in the deal, because of its strong financial interest in oil production (due to royalties, which dominate the state budget) and employment issues.

The FTC staff and the state of Alaska originally divided responsibility for the case so that the state would focus on the upstream (oil exploration and development, pipelines, and marine transportation) and the FTC mainly on the downstream (sales of ANS to West Coast refineries, impact on refined product prices). The theory behind this division of duties was that the state had more expertise in Alaska-specific issues, and that the interests of both the state and the Commission were to promote competition in exploration and development upstream. Downstream there was a divergence of interests, with the Commission preferring lower oil prices for consumers and the state preferring higher prices, which form the basis of its considerable royalties.<sup>2</sup>

While BP and ARCO dominated the North Slope, ARCO was also a major player downstream in California refining and marketing—businesses BP was not in. In fact, ARCO used all its own North Slope production and bought additional crude for its own refineries, raising questions regarding the treatment of captive capacity and the role of integrated firms in merger

<sup>1</sup>BP estimated the overall savings from its acquisition of ARCO at more than \$1 billion per year, mostly from consolidating managerial and administrative operations.

<sup>2</sup>As we shall see, only after Alaska settled with BP by negotiating the Alaska Charter did the Commission begin to focus seriously on upstream issues.

analysis.<sup>3</sup> From a legal perspective, should the deal be viewed as "horizontal," since BP and ARCO were both major *producers* of ANS, or "vertical," since ARCO was a *net buyer* of ANS on the West Coast while BP was a major supplier to ARCO competitors such as Chevron and Tosco?<sup>4</sup>

The analysis of the BP-ARCO merger can be divided into two major parts: upstream issues in Alaska, and downstream issues on the West Coast.<sup>5</sup> We organize our analysis along precisely these lines, starting with the upstream issues. As we shall see, however, an upstream divestiture of assets negotiated between BP and the state of Alaska would prove to have a major impact on the downstream analysis.

## THE UPSTREAM CASE: EXPLORATION AND BIDDING FOR OIL TRACT LEASES

---

The state of Alaska and the federal government regularly auction off the rights to explore and drill for oil on new tracts of land on Alaska's North Slope (both on-shore and off-shore).<sup>6</sup> Under the terms of these auctions, bidders offer a price per acre, subject to a minimum. Winning bidders on a given tract of land obtain exclusive drilling and extraction rights to that tract, but must then pay rent on that tract as well as royalties on any oil that is extracted from it.

As any other sellers would, the state and federal governments benefit from competition in these auctions. The basic upstream antitrust issue was whether the merger of BP and ARCO would substantially reduce competition in these auctions, thus leading to a loss of revenue for the state and federal governments and perhaps to a slower rate of development of North Slope oil tracts.

There were good reasons for Alaska to fear that the merger would reduce its revenues from auctions of oil exploration and production rights. BP and ARCO had historically been the largest bidders in auctions of oil leases

---

<sup>3</sup>The issue of captive capacity was a common one for the FTC. Generally, it preferred to ignore captive capacity, as when it calculated the market share of Intel in microprocessors by ignoring IBM's production for its own use.

<sup>4</sup>Plus, some of ARCO's major competitors (Exxon) were integrated upstream while others (Chevron) had few or no assets in Alaska.

<sup>5</sup>There were also potential antitrust issues involving the Trans-Alaska Pipeline System (TAPS) and marine transportation of crude oil from Valdez, Alaska, to the U.S. West Coast. We do not explore those issues in this case.

<sup>6</sup>The Alaska Department of Natural Resources (ADNR) administers state leases. The Bureau of Land Management (BLM) administers lease sales for federal on-shore properties, and the Mineral Management Service (MMS) administers leases for offshore Outer Continental Shelf federal properties.

in the State of Alaska.<sup>7</sup> In the decade prior to the merger, ARCO accounted for 38.4 percent of all successful bids and BP for 20.2 percent.<sup>8</sup> Other major bidders were Chevron, Phillips, Anadarko, and Petrofina. The FTC estimated that BP and ARCO had been the top *two* bidders on about 15 percent of all the leases that the state had sold. A loss of revenue equal to the difference between the highest and second highest bids in those auctions would have cost the state and federal governments about \$100 million in real terms over the bidding history of the North Slope. Recently, the two firms appeared to be in serious competition with one another in auctions on the western part of the North Slope, in the Alpine and the National Petroleum Reserve-Alaska (NPR) fields.

As usual in any merger involving a bidding market, one must look at the key assets necessary to be an effective bidder, as well as the actual shares of the merging firms in winning, or placing, bids. Here, the key assets include (1) control over processing facilities and feeder pipelines valuable for oil production in new areas; (2) knowledge of the North Slope and experience in operating oil fields there; and (3) three-dimensional (3D) seismic data of the North Slope. In areas (1) and (2), BP and ARCO had advantages over other bidders and could be expected to have lower costs than their competitors for actually conducting North Slope operations. Anyone else who won an oil lease probably would need to negotiate with BP and/or ARCO to provide important services, such as processing facilities, pipelines, or operator services.

Due to their possession of 3D seismic data, BP and ARCO also had some informational advantage over other bidders. The magnitude and durability of this advantage was an issue in the merger review. The data were collected and initially processed by an independent firm, Western Geophysical, raising the possibility that other firms could also contract to obtain such data in the future (as well as obtain existing data as part of a divestiture package).

Information is critical in these auctions; put simply, auctions for oil leases are an information-intensive business. There are good reasons to believe that a bidder with superior information in an area will win the lion's share of the tracts in that area and make almost all of the money.<sup>9</sup> Unin-

<sup>7</sup>Some very interesting issues (beyond the scope of this case) arise in these auctions because joint bidding is common. Even the calculation of market shares is not straightforward in the presence of joint bidding.

<sup>8</sup>These bidding data are publicly available. See ADNR 1999.

<sup>9</sup>To illustrate, suppose that an oil field has a true value that is equally likely to be any amount between 0 and 100. One informed bidder knows the exact value, while others are literally clueless, other than knowing the distribution. Each firm submits a sealed bid, with the highest bid winning. Then the (Bayesian Nash) equilibrium is that the informed bidder will bid half the true value and the uninformed bidders will randomize in such a way that the highest bid among them will be equally likely to be any amount between 0 and 50. In this equilibrium, the informed bidder bids  $v/2$  where  $v$  is the true value, and each uninformed bidder makes zero in expectation regardless of how much it bids: contingent on winning it knows that the true value must be between 0 and twice its

formed bidders do hold down the profits of the informed bidders—if the uninformed bidders did not participate, then a single informed bidder could win all the licenses for next to nothing—but the seller's revenue is considerably lower than when there is competition between *two* informed bidders.

The state of Alaska and the federal government had a strong interest in ensuring that they would receive full value for their property by having competition between equally well-informed bidders. If the two best-informed bidders were to merge, it might be necessary for the state and the federal government to protect themselves in other ways, such as by raising the minimum price or royalty rate at which they would lease fields. But increased minimum prices might cause some leases that otherwise would have been purchased to go unsold. This is hardly a phantom concern: Leases had been awarded on only about 40 percent of the acreage available in state auctions prior to the proposed merger.

During November 1999 Alaska negotiated an agreement with BP that was intended to preserve upstream competition in the bidding for leases and more generally to preserve competition on the North Slope. This agreement known as the "Alaska Charter", was unveiled on December 2, 1999. Under the terms of the Alaska Charter, BP would sell 175 thousand barrels per day (MBD) of ARCO's production to two other production companies<sup>10</sup> along with seismic data and other upstream assets that would make these companies stronger bidders on the North Slope.<sup>11</sup>

BP felt that the Alaska Charter fully addressed the upstream issues raised by Alaska and the FTC. It also believed that the state was the natural party with which to negotiate upstream issues since the FTC seemed focused on the downstream issues, and anyway the state had much greater expertise than the FTC in Alaskan production. Once the Alaska Charter was negotiated, Alaska and BP became allies, at least to the extent of arguing that the Alaska Charter dealt adequately with upstream competition issues. Nonetheless, the FTC later challenged the BP-ARCO merger in court primarily because of upstream issues.

It is doubtful that the FTC knew better than the state about competition within Alaska, but the FTC might have had a better sense of its own bargaining position. For example, the state may have been concerned that if it went to court the government would lose the case and the merger would go through as announced. The FTC probably recognized that BP would regard going to court as very costly. Furthermore, once the state had negotiated the

---

bid, while if the high uninformed bid is equally likely to be any amount between 0 and 50 the informed bidder will maximize expected profits by bidding  $v/2$ . See, for example, Klemperer (1999) for a primer on basic auction theory.

<sup>10</sup>BP was willing to sell all 175 MBD to one buyer if that was the FTC's preference.

<sup>11</sup>The Alaska Charter also required BP to divest the necessary pipeline and tanker capacity to bring this crude oil to the West Coast. We discuss the impact of the Alaska Charter on downstream markets below. The Alaska Charter is available at <http://www.bp.com/alaska/ARCO/charter.htm>.

## Case 5: The BP Amoco-ARCO Merger (2000)

Alaska Charter, its terms would have been binding on BP even if the FTC lost a bid to block the merger. In that sense, the Charter reduced the riskiness to the merger's biggest skeptics of going to federal court to block the merger.

One concern at the FTC was that while ARCO Alaska (the unit within ARCO conducting ARCO's Alaskan operations) was a going business, the smaller companies created or enhanced under the terms of the Alaska Charter might not be viable competitors. These concerns were partially based upon a study of divestitures conducted by the FTC's Bureau of Competition (FTC 1999). This study measured the success of a divestiture by whether the divested assets were later "operated viably" in the same industry they had operated in prior to the divestiture. Of twenty-two divestitures of whole businesses, nineteen were deemed successful by this measure. Of the fifteen divestitures of something other than whole businesses, only six were successful.<sup>12</sup> In addition, information economics implied that the commission should put a thumb on the scale in favor of divesting complete businesses rather than a set of assets cobbled together from two or more separate enterprises.<sup>13</sup> This "clean sweep" policy of selling whole businesses intact made three commissioners lean heavily in the direction of requiring a complete divestiture of ARCO Alaska, or at least something close to it.

The Alaska Charter was negotiated well before the FTC challenged the BP-ARCO deal in court. Therefore, it was natural and sensible to evaluate the impact of the proposed merger *given the Alaska Charter*. Though designed to deal with the *upstream* issues in the case, the Alaska Charter in fact eliminated the rationale for the commission's *downstream* case, which is precisely where the FTC's pre-Charter efforts had been concentrated. This realization gradually led to a change in the FTC's approach to the case, and affected the subsequent litigation in federal court.

## WEST COAST CRUDE OIL SURPLUS, DEFICIT, AND ARBITRAGE CONDITIONS

The remainder of this case study focuses on the downstream impact of the merger. The basic downstream antitrust issue in the BP-ARCO merger was whether the acquisition of ARCO would allow BP to elevate the price of ANS crude oil to West Coast refineries. Ultimately, higher ANS crude oil prices might lead to higher prices of refined products, especially gasoline, on the West Coast. Certainly this concern was salient to politicians in Cali-

<sup>12</sup>There were scientific concerns about the study within the Commission; also, a proper study of the success of the Commission's divestiture policy should evaluate whether consumers were ultimately helped or hurt by the Commission's orders. The Bureau of Competition report ignored this important factor.

<sup>13</sup>A good example of the "sell a whole business" concept was the FTC's decision to ask Exxon Mobil to sell the Exxon jet oil business, which operated on a stand-alone basis, instead of the Mobil business, which did not.

ifornia, Oregon, and Washington. To address these issues, we begin with some background information on the supply and demand of crude oil on the West Coast.

### Quantities, Imports and Exports

In the mid-1970s, West Coast refineries relied largely on California crude oil and imported crude oils. Roughly 45 percent of the crude oil used in PADD V<sup>14</sup> was from California, 45 percent from imports, and 10 percent from Cook Inlet in Alaska. The West Coast was "in deficit"; that is, it was a large net importer of crude. Total use of crude oil was roughly 2.5 million barrels per day, or 2500 MBD.

These conditions were changed dramatically by Alaskan North Slope production of crude oil. ANS production started in 1977, peaked around 1990 at about 2000 MBD, and has now declined to about 1000 MBD, as shown in Figure 5-1.

When ANS production was high, the West Coast was "in surplus" as a net exporter of crude. But by 1999 the West Coast was again deeply in deficit, importing more than 600 MBD of crude oil, as shown in Figure 5-2. By 1999, some 42 percent of crude oil used on the West Coast was from Alaska, 33 percent from California, and 25 percent from imports; see Figure 5-3. Of the Alaskan oil, three-fifths was sold on the merchant market (this includes all of BP's ANS), and the rest was transferred internally (primarily ARCO and Exxon ANS crude oil used in their own West Coast refineries).

### Crude Oil Prices

As a general principle, the price of ANS crude oil closely tracks other crude oil prices over time. Figure 5-4 shows the price of ANS and a number of other crude oils between 1989 and 1999. In this sense, crude oil prices on the West Coast are governed by conditions in the world crude oil market. The spike in prices in 1991, for example, reflects the Gulf War. The correlations among these different crude oil price series are very high, typically in the 0.97 to 0.99 range. However, price differentials between different grades of crude oil do vary somewhat over time. We will be examining these differentials closely. In particular, we look closely at the time series of the difference between the price of ANS crude oil and the price of the benchmark West Texas Intermediate crude oil (WTI).<sup>15</sup>

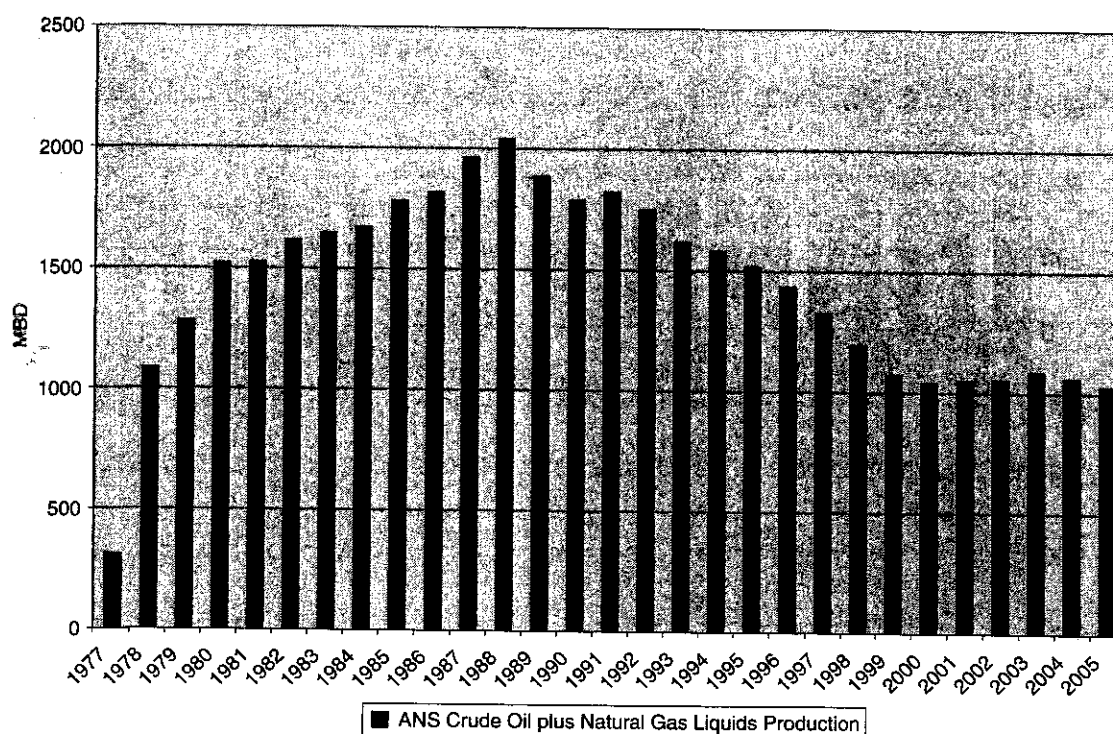
The price differentials between ANS and WTI crude oils can largely be explained by import and export arbitrage conditions. In the late 1980s and

---

<sup>14</sup>Much of the data in this industry actually covers Petroleum Area Defense District (PADD) V, which encompasses not only California, Oregon, and Washington, but also Alaska, Hawaii, and Arizona.

<sup>15</sup>ANS is more "sour" and thus cheaper than WTI, so the ANS-WTI price differentials are negative numbers.

FIGURE 5-1 Alaska North Slope Crude Oil Production, 1977–2005



Source: State of Alaska Department of Natural Resources. Note: 2000–2005 data are projected.

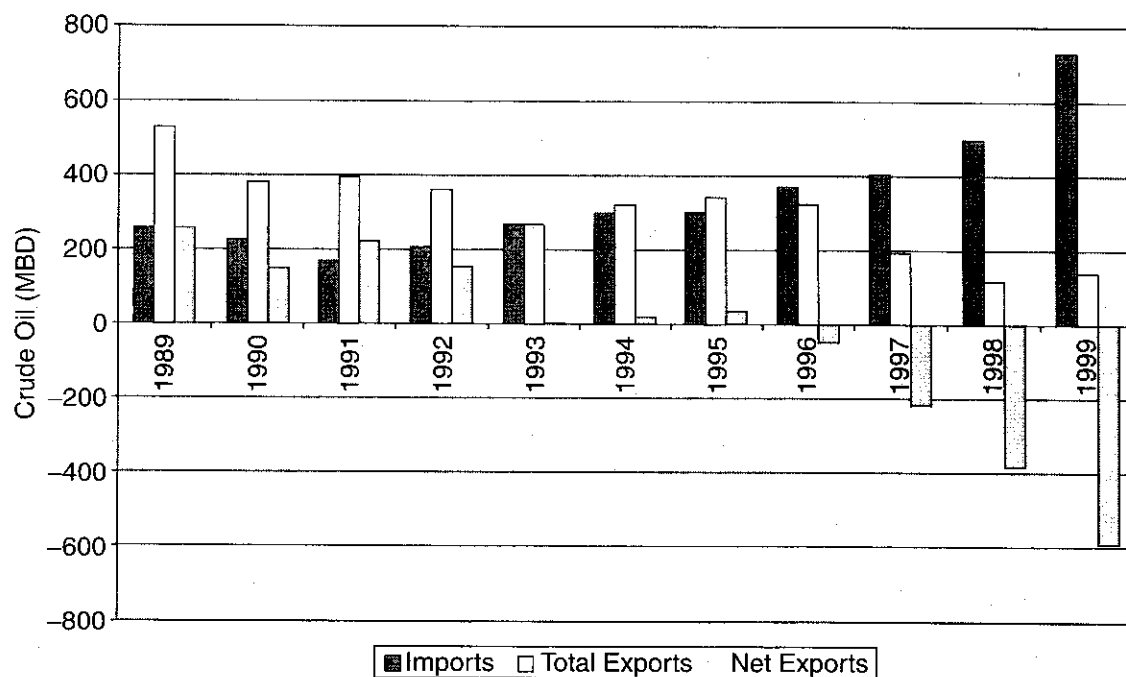
early 1990s, the West Coast was in surplus, and foreign exports of ANS crude oil were prohibited. Therefore, some ANS crude oil had to be transported beyond the West Coast to the Virgin Islands and the Gulf of Mexico, where it would compete with WTI and other crudes. Competitive market arbitrage implied that the West Coast price should be the price in the alternative markets, *minus* the incremental transit costs. In the late 1990s, with the region in *deficit*, transit was going the other way. A competitive West Coast price for ANS crude oil should have reflected the price of crude in other markets, *plus* any incremental cost of shipping that crude to the West Coast. The price of ANS crude oil rose relative to WTI crude oil by about \$1.50 from 1993 to 1995, as the market moved from surplus to balance and later into deficit (see Figure 5-2).

Ironically, the move from surplus to deficit both raised prices and reduced the chance that the merger would elevate ANS crude prices. Once the West Coast was in deficit, BP, ARCO, and Exxon were able to sell their oil at the cost of imports plus transit costs from a competitive world market. Increasing the shortage by exporting out of the region would not raise prices very much, as the supply of imports was highly elastic, and therefore would only be a viable strategy if transport costs were very low. By contrast, in the early 1990s it was theoretically possible that an increase in exports could have raised prices significantly by moving total supply from surplus to shortage, potentially making exports profitable for a large supplier, even one with high transit costs.



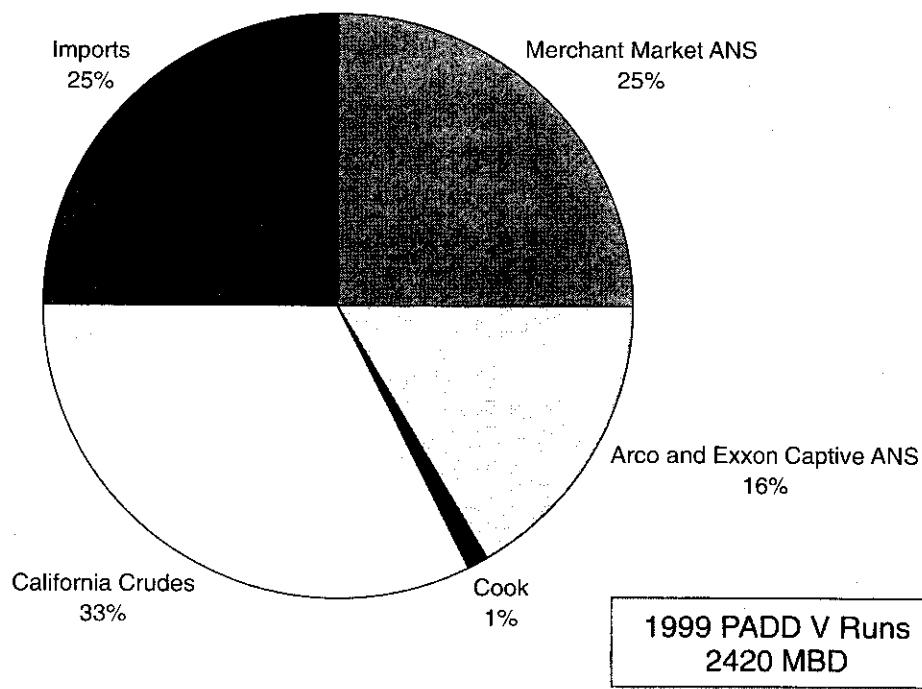
## THE ANTITRUST REVOLUTION

FIGURE 5-2 PADD V Imports and Exports, 1989-1999



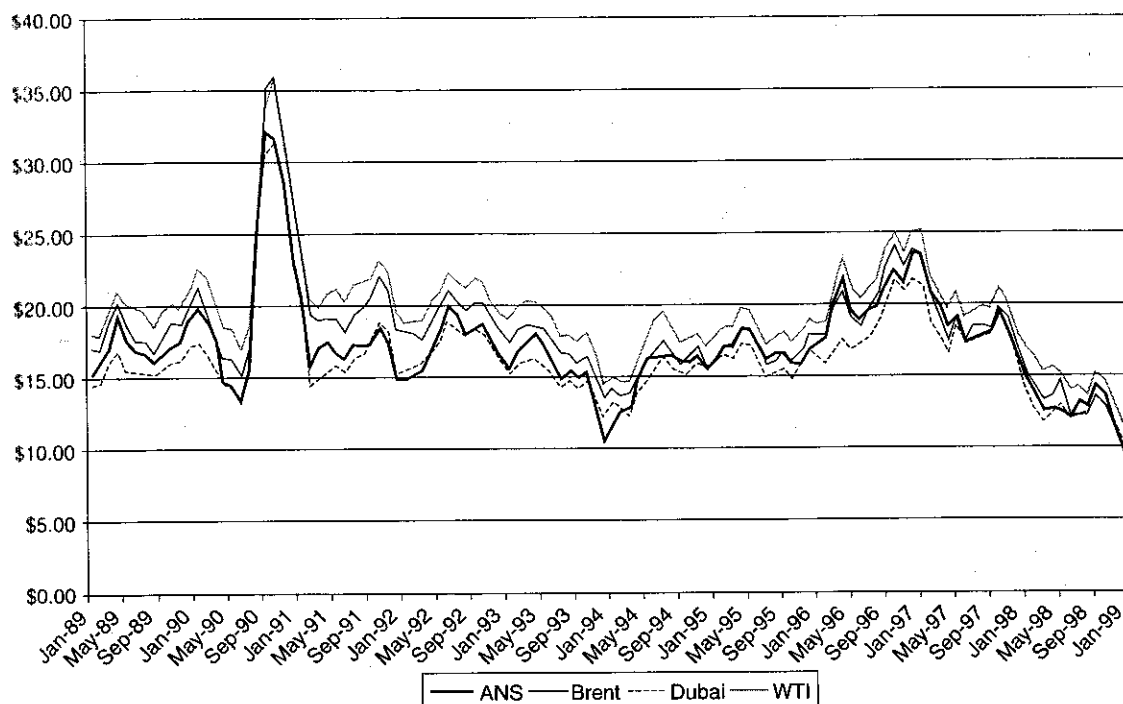
Source: Department of Energy (Energy Information Administration) and company data.

FIGURE 5-3 Usage of Crude Oil in PADD V, 1999



Source: Company data.

FIGURE 5-4 Monthly Prices (per barrel) for Select Market Crudes



Source: Reuters (ANS), Nymex (WTI), Platts (Brent and Oman).

### Demand for ANS since 1995

Since 1995, as shown in Figure 5-2, PADD V has increasingly relied upon imports to meet its crude oil needs. Data from this period provide strong evidence that West Coast refineries were capable of replacing ANS crude oil with foreign crude oils without incurring substantial incremental costs as a result of this substitution. In other words, the intermediate to long-term elasticity of demand for ANS crude oil on the West Coast is very high. Imported crude oils are very close substitutes for ANS crude oils.

The experience of California refineries is illustrative. From 1995 to 2001, ANS crude sold in California declined by 342 MBD, from 725 MBD to 383 MBD; balancing this, imports rose by 370 MBD, from 156 MBD to 526 MBD.<sup>16</sup> Despite this tremendous decline in ANS crude oil availability, the price of ANS crude did not rise at all relative to the price of WTI. In 1995, ANS crude sold for an average of \$5.91 per barrel less than WTI; in 2001, the differential was actually higher, at \$6.44.<sup>17</sup>

Declining ANS crude oil production is a wonderful natural experiment that reveals a great deal about the demand for ANS crude oil on the West

<sup>16</sup>Source: [http://www.energy.ca.gov/fuels/oil/\\_crude\\_oil\\_receipts.html](http://www.energy.ca.gov/fuels/oil/_crude_oil_receipts.html).

<sup>17</sup>These data are taken from the Energy Information Administration website. See [http://www.eia.doe.gov/pub/oil\\_gas/petroleum/data\\_publications/petroleum\\_marketing\\_monthly/current/pdf/pmmtab22.pdf](http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/current/pdf/pmmtab22.pdf). In real terms the ANS discount declined slightly.

Coast. A huge, exogenous supply shock (gradually over a period of years) is perfect for statistically "identifying" the demand curve. Since large declines in ANS crude oil production were accommodated without any increase in price (since the West Coast went into deficit in 1995), we know that the shift from ANS crude oil to imported crude oils was quite inexpensive for West Coast refineries as a group. In other words, the intermediate-run elasticity of demand for ANS crude oil specifically is extremely high.<sup>18</sup> We say "intermediate-run" here because the decline in ANS crude oil production was widely anticipated, so refineries could and did plan to shift away from ANS crude oil. California refineries were required to renovate substantially to meet new environmental standards (specifically, to produce the so-called CARB gasoline required by the California Air Resources Board), and it was reasonable for refiners to increase their flexibility in the crude oils that they could process as part of their renovations.

This flexibility can be seen at the refinery level, as well as in the aggregate. Major refineries on the West Coast were owned by Chevron, ARCO, Equilon (a joint venture of Shell and Texaco), Tosco, and others. While some refineries made little change in their crude oil slate during the 1990s, others, most notably Chevron, made dramatic shifts toward greater use of imports.

### Implications for the BP-ARCO Merger

The primary mechanism for raising West Coast prices after the merger would have been for BP to increase exports to the Far East. But experience from 1995 to 1999 showed that reduced ANS crude oil shipments would not, over the intermediate and long term, lead to higher crude prices. Even over the short run, it appeared that exports could only be profitable if shipping costs were extremely low.

For precisely these reasons, both of the authors concluded that the proposed merger would not elevate ANS crude oil prices on the West Coast in any significant way; this conclusion was even stronger after the negotiation of the Alaska Charter, which further reduced BP's incentive or ability to export ANS crude oil to the Far East. But these conclusions needed to be tested against, and reconciled with, evidence on BP's premerger ANS crude oil trading and export strategies, to which we now turn.

## BP'S ANS EXPORT AND PRICING STRATEGY

---

We now examine how this high-level, long-term view of the market based on import and export arbitrage conditions contrasts with the short-term

---

<sup>18</sup>See "Market Definition in Crude Oil: Estimating the Effects of the BP/ARCO Merger," by John Hayes, Carl Shapiro, and Robert Town, for an econometric analysis of the demand for ANS crude oil.

strategies adopted by BP for exporting ANS crude oil and for pricing ANS crude oil to West Coast refineries.

BP's export, trading, and pricing strategies for ANS crude oil provide an excellent example of how basic economic principles can be used in business. BP's short-term trading activities, conducted in the context of a competitive world market for crude oil, illustrate nicely one of the basic tools of price theory, namely the distinction between price and marginal revenue. While there was some dispute over whether BP had any meaningful market power, even in the short run, there was little doubt that BP's export, trading, and pricing strategies applied standard microeconomic principles that are taught to students and are used by many businesses to maximize profits. There was never any suggestion that BP's basic export and pricing strategies were exclusionary or somehow "unfair." Rather, the question was whether they indicated that BP possessed market power, and, if so, whether that market power would be enhanced by its acquisition of ARCO.

Naturally, refineries may enjoy far less flexibility in their choices of crude oils over the short term (a few weeks or months) than over the intermediate or long term, when refineries can be modified to handle alternative crude oils. A close look at BP's sale of ANS to West Coast refineries therefore gives us an opportunity to explore the following classic puzzle: can a supplier exercise persistent *short-term* market power even if *long-term* demand is highly elastic?

When one looks more closely at the sale of ANS crude oil on the West Coast, the simple long-term picture driven by arbitrage conditions, while reflective of overall competitive conditions, becomes considerably more complex. To begin with, the *average* reported price of ANS crude oil (as used above) masks some variation in prices across different refinery customers. In fact, there was strong evidence that BP was able to exert some modest market power in the short run, even though in the medium to long term BP was very much subject to the powerful arbitrage constraints described above. The primary evidence regarding BP's short-term market power was BP's own pricing strategy and behavior; evidence on price discrimination was also present, but was murkier. We discuss these types of evidence in turn.

As we turn to look more closely at BP's trading strategies, it is well to bear in mind that here, as in other commodity markets, conditions change week to week and traders are always attempting to assess the strength or weakness of the market. In the West Coast crude oil business, demand can suddenly shift down if a refinery experiences an outage or if a pipeline carrying refined products has a fire; supply can be disrupted due to problems on the North Slope, on the Trans-Alaska Pipeline Systems (TAPS), at Valdez (the terminus of TAPS where ANS is loaded onto tankers), or with the oil tankers that bring oil from Valdez to the West Coast. Market conditions also shift if, for example, a refinery arranges for an extra cargo to be delivered from the Mideast and thus requires less Alaska crude oil in two or

years)  
ge de-  
ny in-  
know  
expen-  
ediate-  
high.<sup>18</sup>  
il pro-  
o shift  
novate  
roduce  
ources  
in the

aggre-  
ARCO,  
e some  
others,  
ports.

merger  
rience  
would  
. Even  
f ship-

ie pro-  
cast in  
tiation  
to ex-  
to be  
crude

based  
t-term

by John  
IS crude

three months time. In short, even in highly competitive commodity markets, short-term supply and demand imbalances often occur, in some cases conferring short-term market power on certain market participants.

### BP's Optimizer Model

BP's approach to selling ANS on the West Coast was highly scientific. BP used a tool called the Optimizer Model to inform its crude oil trading activities on the West Coast. Basically, the Optimizer Model was BP's attempt to estimate the short-run demand curve for ANS crude oil on the West Coast and to account for how spot prices would affect BP's revenues on its term contracts. By looking carefully at each refinery customer, BP attempted to estimate the price at which that customer would substitute imported crude oil for ANS. For example, the Optimizer Model might indicate that (given the price of other crude oils) a particular refinery would buy an extra 15 MBD of ANS crude oil if it could be acquired at \$3.00 less than the price of WTI. This estimate of demand might depend on the availability of other crude oils as well as the prices at which different outputs (gasoline, jet fuel, diesel fuel) could be sold by that refinery, since the output mix would be affected by the input mix. BP used the Optimizer Model in two main ways, which we discuss in turn.

### Exports to the Far East

First, BP sought to price discriminate between the West Coast and the Far East. BP sold a significant volume of its ANS crude oil to West Coast refineries according to term contracts that specified a price linked to the U.S. West Coast (USWC) spot price for ANS crude oil. Shipments to the Far East had the effect of "tightening" the West Coast market, thereby increasing USWC spot prices and yielding BP higher revenues on its West Coast term contracts. By some estimates, BP at times found it profitable to sell in the Far East for a netback (price less transportation cost) that was up to forty cents per barrel lower than it could get in California.<sup>19</sup> In economic terms, if BP sold the last cargo to Korea the price and marginal revenue from the shipment would be the same, but if BP instead sent this cargo to the West Coast the slight easing it would cause in West Coast contract prices (multiplied by the far larger volume sold under the term contracts than sold on the spot market) would mean that BP's marginal revenue would be forty to fifty cents below the price it would receive.

---

<sup>19</sup>The formula relating marginal revenue (MR) to price (P), when all competitors' quantities are held fixed, is  $MR = P(1 + s/Z)$ , where  $s$  is the firm's market share and  $Z$  is the demand elasticity. In this case if the price of crude oil was \$15.00 a barrel and the elasticity of demand was  $-15$ , then if BP had a 40 percent market share there would be a \$0.40 differential on the West Coast between marginal revenue and price.

## Case 5: The BP Amoco-ARCO Merger (2000)

Furthermore, it was often feasible for BP to get a Far East netback that was within forty to fifty cents of the West Coast netback. While the cost of shipping from Alaska to Korea on a *charter* was several dollars per barrel more than shipping to California, BP owned some excess shipping capacity in the late 1990s, since the decline in ANS crude oil production had left BP with more Jones Act<sup>20</sup> tankers in Alaska than it had capacity to use, at least until tanker retirements caught up with the production decline. All ships transporting Alaskan oil were and are Jones Act vessels. The decline in North Slope production created a short-run excess supply of Jones Act shipping capacity, which could not be practically used elsewhere. So effectively the marginal cost of shipping to the Far East instead of the United States, given that the crew and tanker were already paid for, was only the extra fuel cost. BP's excess shipping capacity made the short-term economics of exporting much more attractive than they would be if long-run costs had to be considered: It would never be profitable to build Jones Act tankers for the purpose of exporting from Alaska to Asia. The FTC's economic analysis thus implied that BP would stop exporting as soon as tanker retirements caught up with the decline in Alaskan oil production. In fact exports virtually ceased in April 2000.

BP's ability to influence the price of ANS through exports, at least in the short term, was highly significant to the FTC, which viewed the optimizer model as proof that BP had at least some market power. BP's contracts tying ANS crude oil prices to USWC prices instead of a world benchmark such as WTI represented some of the best economic evidence that the ANS crude oil prices moved somewhat separately from WTI prices. If the ANS crude oil price were rigidly tied to the WTI price, why would the vast majority of BP's contracts be based on a separate West Coast ANS crude oil price? After all, the USWC market had to be less liquid and more easily subject to manipulation. One explanation would be that refiners might have preferred USWC pricing if they thought that the prices that they would receive for their output would be more closely tied to the USWC price. But this would imply that differences between the USWC and world prices not only were likely to occur but to be passed through to consumers, an additional concern to the FTC.

However, if the Optimizer Model presented the clearest evidence that BP operated as though it had at least some market power, it also indicated that BP did not think it had very much at all. Even if BP exported to its physical limit (which it did not), the model predicted that West Coast prices of ANS crude oil would be only slightly higher than if there were no exports at all. The FTC's expert witness, Preston McAfee (2001), estimated that BP's exports raised the price of ANS by about a half a cent per gallon at the refinery level.

<sup>20</sup>The Jones Act (also known as the Merchant Marine Act of 1920) and related statutes require that vessels used to transport cargo and passengers between U.S. ports be owned by U.S. citizens, built in U.S. shipyards, and manned by U.S. citizen crews.

### Negotiations with Refineries on the West Coast

BP negotiated terms and conditions separately with each refinery customer. These terms were then reflected in the Optimizer Model. In a purely competitive market everyone would be buying at the same margin of price over cost. BP claimed that some of the price differences across refineries were due to cost differences in supplying different refineries (it is cheaper to supply a refinery with superior port facilities, or a refinery that fits better with the supplier's marine logistics). But some of the price differences were simply the result of bilateral bargaining. While some within the FTC gave some credence to the cost explanations, others viewed price differentials among West Coast refineries as further evidence that BP had market power.

### The Impact of BP's ANS Exports on Prices

While it was clear what BP was doing, because BP's thinking was so systematic, BP's actions probably had very little impact on the average price of ANS crude oil on the West Coast, and even less of an effect on gasoline prices. Certainly, if one takes the longer-term view described earlier, dramatically declining ANS shipments to the West Coast had no lasting impact on ANS crude oil prices, so BP's much smaller exports could not have had any lasting effect on crude oil prices, much less gasoline prices. Even if one focuses on the BP's short-term trading and exporting strategies, however, the magnitude of their impact was quite small, as we now demonstrate.

### Crude Oil Prices

Exports of ANS crude oil to the Far East averaged about 80 MBD during the mid- to late-1990s.<sup>21</sup> Even assuming that all these exports were BP's (close) and that none of the exports would have been made in a competitive market (this is not correct; for example, West Coast refinery shutdowns would sometimes push California netbacks below Far East netbacks), then the impact on ANS prices would have been small—recall McAfee's estimate of a half penny a gallon. From a larger perspective, ANS production had declined by hundreds of MBDs during the mid- to late-1990s with no increase in the price of ANS relative to other crude oil prices, casting serious doubt on the proposition that 80 MBD of ANS exports would elevate ANS prices on the West Coast, given the elastic supply of imported crude oil.<sup>22</sup>

<sup>21</sup>The actual averages of exports from PADD V for 1995–1999 were 94, 94, 78, 54, and 74 MBD, returning to 92 MBD during the first four months of 2000. Source: Petroleum Supply Annual, various issues. It is fair to assume that the vast majority of these exports were ANS, and the vast majority of the ANS exports were sold by BP.

<sup>22</sup>The November 2002 earthquake in Alaska caused an unanticipated reduction in ANS supplies of about 3 million barrels (3 days' supply) but apparently did not affect West Coast prices. See Barrionuevo (2002).

## Gasoline Prices

How would a penny per gallon elevation of the price of ANS crude oil affect average *gasoline* prices on the West Coast?<sup>23</sup> Here is an illustrative calculation.<sup>24</sup>

Economic theory says that if the downstream market is competitive then a parallel upward shift in the market marginal cost or supply curve should be passed through in proportion to the relative elasticities of supply and demand. The passthrough rate for increases in marginal costs is  $S/(D + S)$ , where  $D$  is the absolute value of the elasticity of demand and  $S$  is the elasticity of supply. It is fair to say that both supply and demand for gasoline are highly inelastic on the West Coast, so any estimate of the specific pass-through rate would involve the division of one small number by the sum of two small numbers, and therefore be of questionable reliability.<sup>25</sup>

A related issue was how much an increase in the cost of ANS crude oil would affect the marginal cost of production of refined products. This depends upon the elasticity of substitution between ANS and other crude oils, especially imported crude oils. As a first approximation, one could say that if ANS comprised 40 percent of the crude oil used on the West Coast, then a 1 percent increase in ANS crude oil prices might lead to a 0.40 percent increase in marginal costs.<sup>26</sup> So, even if 100 percent of any marginal cost increase were passed through to consumers, as would happen if the supply curve were flat, then the overall pass-through rate of ANS crude oil prices to gasoline prices would be 40 percent. If only ANS crude oil merchant market sales are counted, the relevant figure would be only 25 percent (see Figure 5-3).

Given the agreement by all of the FTC investigators in the Exxon-Mobil merger that the supply curve of refiners was quite inelastic, which would imply a lower pass-through rate, 45 percent seemed to be a reasonable working upper bound on the actual pass-through rate of ANS prices to gasoline prices. If this logic is followed, a penny a gallon of ANS crude oil would translate to an average of no more than 0.45 cents per gallon of gasoline, and probably quite a bit less.

<sup>23</sup>One barrel contains forty-two gallons. As a rule of thumb, one barrel of crude oil produces one barrel of gasoline. The production process involves some loss of volume, but this is made up by the addition of other inputs, which adds to volume. So, forty-two cents per barrel of crude oil translates roughly into a penny a gallon.

<sup>24</sup>The passthrough rate of crude oil prices to gasoline prices was the subject of considerable attention in the BP-ARCO merger. Space limitations do not permit us to develop this vertical part of the analysis further in the current case.

<sup>25</sup>The General Accounting Office (1999) estimated that the prices of ANS and certain comparable California crudes increased by \$0.98 to \$1.30 per barrel during the mid-1990s, but also estimated that the effect at the consumer level was "insignificant." Given the small change in the relative price of ANS over the 1990s while production declined by 1000 MBD, this estimate of the effect of 80 MBD of exports on crude prices seems implausibly high. However, a zero pass-through rate of refinery-level cost increases to consumers seems implausibly low.

<sup>26</sup>This would be precisely right with Cobb-Douglas production functions.



## THE ANTITRUST REVOLUTION

Furthermore, any price discrimination between refineries would be unlikely to affect retail prices. With perfect price discrimination an ANS crude oil monopolist would sell its oil to the same firms, in exactly the same quantities, as would occur in a market with price-taking, competitive ANS crude oil suppliers. While refineries would pay more in the price discrimination case for the same quantity of ANS crude oil, there would be no efficiency loss, implying that the quantity of all outputs produced at the retail level, and therefore all retail prices, would be exactly as in the competitive case. Compared to the simple monopoly (no price discrimination) case, where a monopolist could only raise its price by cutting output or, more likely, exporting, consumers would be *better* off with perfect refinery price discrimination because the monopolist would no longer need to export to get a high price and therefore would supply more to the domestic refiners.

One could envision that a modest increase in ANS crude oil prices resulting from exports might have some long-run impact on entry and exit from refining; however, due to the nature of the industry, that was very unlikely. First, no new refinery has been built in the United States in several decades, so de novo entry was highly unlikely in the best of circumstances. Second, while firms did invest in upgrading refineries to expand output by 1 or 2 percent per year, it is unclear whether BP's strategy served to dampen or increase such investment. A byproduct of many refinery upgrades was to reduce the refiner's dependence on any specific crude oil such as ANS. If BP behaved opportunistically, then a refiner might be *more* motivated to upgrade. (Recall the very high long-run elasticity of demand for ANS.) Third, in at least one case it appeared that BP's price discrimination helped keep a marginal refiner in business. The impact of this action was probably to *enhance* downstream competition, to the benefit of consumers.

### Implications for the FTC's Merger Review

To summarize, there were legitimate reasons to believe that BP's strategy of exporting some ANS crude oil to the Far East had a slight upward effect at certain times on West Coast ANS crude oil prices, perhaps as much as a penny a gallon. At most this could have translated into 0.4 cents per gallon of gasoline. BP disputed these price effects, pointed out the inconsistencies between such alleged price effects and the longer-term evidence on ANS crude oil production and prices, and argued that ANS prices were at competitive levels. But BP's Optimizer Model, BP's trading strategies, and BP's exports to the Far East were central to the FTC's view of the proposed merger. Because of these exports, and the Optimizer Model, FTC lawyers took the position that BP already enjoyed some market power prior to its acquisition of ARCO. Still, such a finding would not be sufficient to challenge the acquisition, which would require the FTC to show that BP's merger with ARCO would strengthen or sustain BP's market power.

## WHAT ABOUT ARCO?

---

As just explained, some in the FTC placed great weight on the observation that BP exerted some market power in the short term. They considered BP's exports to the Far East as proof that BP had monopoly power over ANS crude oil, and sought to use the merger review, and associated settlement, to prevent such exports in the future.

However, the conventional question in merger analysis (as called for under the Clayton Act) is whether the proposed merger will *reduce* competition, not whether one of the merging parties enjoyed some premerger market power. In particular, in following its own *Horizontal Merger Guidelines*, the FTC would ask whether the proposed merger would *raise* the price of ANS crude oil sold on the West Coast. Even without any consent decree, BP's incentive to export would be increased only marginally by the merger, and then only for the short time until its excess shipping capacity was retired. And once BP and Alaska agreed that BP would sell a significant fraction of ARCO's reserves as part of an upstream settlement it appeared that the merger would actually *reduce* BP's incentive to export, thereby slightly *lowering* West Coast prices, as we show below. Therefore, once the Alaska Charter was negotiated, it was not possible economically to justify blocking the merger based on the downstream case.

## WHAT HAPPENED

---

We now turn to the resolution of the case.

### Alaska Charter

The Alaska Charter was designed as an *upstream* remedy. However, what the Alaska Charter fixed most persuasively was any *downstream* problem based on BP's trading and export strategies. Prior to the Alaska Charter, ARCO's production of ANS was equal to roughly 90 percent of its consumption. The Charter required the sale of half of the ARCO production. This meant that ARCO's ANS crude oil production would only be 45 percent as great as its consumption. After the divestiture, ARCO's interest would be in *lower* ANS crude oil prices: For every barrel of ANS crude oil that ARCO consumed it would produce 0.45 barrels of ANS crude oil, so a \$1 per barrel price increase would cost it fifty-five cents per barrel consumed. But the FTC's estimate of the pass-through rate implied that ARCO would be able to raise retail prices by at most forty-five cents for every dollar increase in ANS crude oil prices. So after its divestiture, ARCO would lose at least a dime on the dollar from an ANS crude oil price increase.

Now consider the merger. BP clearly gained from any increase in ANS crude oil prices; but if ARCO lost, then the net gain to BP from any price in-

crease would be lower postmerger than premerger. The merger would *reduce* incentives for exports and therefore lead to *lower* West Coast ANS crude oil prices, so long as the merger would not cause any decline in upstream production. In other words, the BP-ARCO merger, along with the Alaska Charter, would be *better* than the status quo for West Coast consumers.

Some in the FTC had a second concern about the Charter that was at best controversial. As part of an earlier deal to pass legislation permitting ANS crude oil exports, BP had committed to California Senator Feinstein that it would use costly, inefficient Jones Act vessels on any shipments of oil from Alaska to the Far East. A new buyer might not be so constrained and therefore would have lower shipping costs to the Far East. Those lower costs might lead to more exports in a competitive market and therefore higher U.S. prices. The argument really boiled down to claiming that the antitrust authorities, in their role as protectors of U.S. consumers, should examine closely transactions that would involve the sale of assets to competitive firms with highly efficient export technologies, on the grounds that such acquirers would increase exports and therefore raise domestic prices.<sup>27</sup> While this might be politically attractive as trade policy, it is not, in our view, sound competition policy.

## BP's Offers

In response to the FTC economists' concerns, BP agreed to alter its supply contracts so that they would be indexed to crude oil prices other than ANS spot prices. This meant that BP would no longer have any incentive to export based on West Coast marginal revenue being less than price. The contracts committed BP's ANS crude oil for years to come (after accounting for usage at the ARCO refineries and the Alaska Charter), so that BP would be net "short" of ANS crude oil. In fact, BP would in the position of benefiting from relative *declines* in the price of ANS crude oil! While these contracts were favorable to refiners, who benefited from knowing that the FTC was forcing BP to renegotiate, they did create a litigation dilemma for the FTC: It meant that the buyers of ANS crude oil were virtually unanimous in wanting the deal to go through so their contracts would become effective.

The FTC has a general tendency to be wary of contractual remedies, relative to divestitures. The two reasons in favor of accepting contracts in this case were that the identified downstream problem appeared to be contractual in nature, and that the problems appeared to be short term. That is, the initial incentive to export came from the indexing of the contract prices to the USWC price instead of the WTI price. In any event, within two or three years BP would no longer have the shipping capacity needed to ex-

<sup>27</sup>Perhaps a more charitable view would be to say that the majority viewed the Jones Act as a tax that benefited American maritime workers and it wanted firms to make decisions that were independent of this tax.

## Case 5: The BP Amoco-ARCO Merger (2000)

port. Furthermore, with a five- to ten-year contract, refineries would have plenty of time to eliminate any dependence they might have had on ANS crude oil. The only coherent reason for the FTC to reject BP's offer would thus have to be based on a concern that the real problem was not with the downstream markets at all but with the upstream ones.

### Settlement

After the FTC turned down the Alaska Charter and the supply contracts as inadequate, BP made a series of "improved" offers. Ultimately BP was willing to sell as much production as ARCO owned, but it had a preference for selling part of BP's old acreage and part of ARCO's rather than all of ARCO's, to maintain some of the merger efficiencies, especially the consolidation of Prudhoe under one operatorship.

There was a heated debate within the Commission about the final BP proposals. Many of the staff argued that even though it appeared likely that BP would ultimately agree to sell all of ARCO Alaska, the deal on the table was better than that for consumers and for economic efficiency. Others, citing the Divestiture Study, claimed that the BP proposal to sell parts of both its and ARCO's holdings was a classic case of "mix and match," that is, a motley collection of assets that would be less likely to be a viable business than the current ARCO Alaska. But in this case selling the assets inefficiently did not make economic sense for BP, given the demand elasticity for ANS. That is, the reduction in revenues from selling an inefficient package would overwhelm any price increase BP might enjoy because of reduced output caused by an inefficient asset package. Furthermore, BP's proposals all made logical sense in terms of being designed to maximize the efficiencies that the company had claimed from the very beginning of the investigation.

On February 2, 2000, the Commission voted three to two to sue BP and ARCO and block the merger. Two months later, BP's CEO John Browne, not eager to go to court against the government of a country where he had major operations, decided to accede to the FTC's divestiture demands. The final deal announced on April 13, 2000, was that BP would sell the entire business of ARCO Alaska to Phillips Petroleum. Because ARCO Alaska was organized as a separate company, all of whose stock was owned by ARCO, in some ways this made for an easier divestiture than a sale of assets.

One additional issue arose—whether the consent order should include a ban on exports, by either BP or Phillips. There were three good reasons for opposing such a ban. First, there are times when exports are efficient, as when some West Coast refining capacity is out of operation. It is difficult to write a rule that only prohibits "inefficient" exports. Second, such a remedy would be "regulatory" rather than "structural" as the Commission generally preferred. Indeed, with the other aspects of the settlement and with BP's declining shipping capacity it was highly unlikely there would be any exports even in the absence of such a provision. Also, an export ban did not appear

to correct any competition problem associated with the merger, especially given the divestiture of ARCO Alaska to Phillips. Third, Congress had explicitly allowed exports in 1995, reversing a long-time ban. It did not seem to be the FTC's place to overrule Congress. Three commissioners agreed with this logic, and the export ban was defeated three to two.

### Postscript

After the merger was finalized, BP, Phillips, and Exxon worked out a way to gain the efficiencies initially visualized by BP. Prudhoe Bay is now operated by BP, which owns 26 percent compared to 36 percent each for Exxon and Phillips.<sup>28</sup> Oil and gas ownership rights were traded among the three companies to better align their incentives and make efficient investment decisions more likely.

An interesting organizational angle relates to the fact that BP and ARCO were unable, over many years, to find a way to renegotiate their working arrangements at Prudhoe Bay, despite the very substantial efficiencies associated with having one rather than two operators of the field. Perhaps their inability to eliminate the awkward dual-operatorship regime was due to fierce pride regarding North Slope know-how. BP, seeing itself as the best oil company in the world, naturally thought it should be the operator; Sir John Browne even got his start on the North Slope. Alaska was the crown jewel of ARCO's exploration and production operations and the place where ARCO trained many of its best people. ARCO may well have thought that because Alaska was so much more important to it than to BP that ARCO was the more appropriate operator; in any event, it would have been demoralizing for the ARCO employees to give up the ARCO operatorship in Prudhoe. After the sale, Phillips had no such corporate history, and quickly cut a deal with BP.

According to the *Merger Guidelines*, for the efficiencies from a merger to be considered as an offset to anticompetitive effects, they must be merger-specific. Did the switch to one operator at Prudhoe Bay qualify as merger-specific? The efficiencies could not have been achieved without a merger, but they were in fact achieved with a merger *cum* divestiture.

There have been no exports of crude oil from Alaska to the Far East since the deal closed.

## CONCLUSIONS

---

BP-ARCO is one of several examples of major oil mergers that occurred in the last years of the Clinton administration. It is fair to say that in each of these cases the companies agreed to divestitures that went well beyond

---

<sup>28</sup>BP also operates the Prudhoe "satellite" fields, which have essentially the same ownership structure as the main field.

## Case 5: The BP Amoco-ARCO Merger (2000)

what many believed were necessary to protect competition. While in many industries the changes in antitrust policy associated with the shift from the Clinton administration to the Bush administration may prove to be marginal, the oil industry is one area where a new majority at the FTC may lead to a significant shift in antitrust enforcement.

## REFERENCES

---

- Alaska Department of Natural Resources. "FTC Briefing Presentation Acquisition of ARCO by BP-Amoco" available at <http://204.126.119.8/oil/products/slideshows/ftc%5Fbriefing%5Fapr1999/index.htm>, April 1999.
- ARCO, British Petroleum, and the State of Alaska. "Charter for Development of the Alaskan North Slope." (Alaska Charter). <http://www.bp.com/alaska/ARCO/charter.htm>. November 1999.
- Barrionuevo, Alexi, "Diversification Checks Prices of Fuel in Pipeline Shutdown." *Wall Street Journal*, November 7, 2002.
- California Energy Commission. "Oil Supply Sources to California Refineries." [http://www.energy.ca.gov/fuels/oil/\\_crude\\_oil\\_receipts.html](http://www.energy.ca.gov/fuels/oil/_crude_oil_receipts.html). February 2002.
- Energy Information Administration. "Petroleum Marketing Monthly." See [http://www.eia.doe.gov/pub/oil\\_gas/petroleum/data\\_publications/petroleum\\_marketing\\_monthly/current/pdf/pmmtab22.pdf](http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/current/pdf/pmmtab22.pdf). May 2002.
- Energy Information Administration. "Petroleum Supply Annual." Various issues.
- Federal Trade Commission, Bureau of Competition. "A Study of the Commission's Divestiture Process." See <http://www.ftc.gov/os/1999/9908/divestiture.pdf>. August 1999.
- General Accounting Office. "Alaskan North Slope Oil: Limited Effects of Lifting Export Ban on Oil and Shipping Industries and Consumers." GAO/RCED-99-191. Available at <http://www.gao.gov/archive/1999/rc99191.pdf>. July 1999.
- Hayes, John, Carl Shapiro, and Robert Town. "Market Definition in Crude Oil: Estimating the Effects of the BP/ARCO Merger." Mimeo. 2002.
- Klemperer, Paul. "Auction Theory: A Guide to the Literature." *Journal of Economic Surveys* 13 (July 1999): 227-286.
- McAfee, R. Preston, "West Coast Gasoline Prices." Prepared statement before the Committee on Commerce, Science, and Transportation, Subcommittee on Consumer Affairs, Foreign Commerce, and Tourism, United States Senate, April 25, 2001.

# The Antitrust Revolution

**Economics, Competition, and Policy**

Fourth Edition

John E. Kwoka, Jr.  
Lawrence J. White

New York    Oxford  
OXFORD UNIVERSITY PRESS  
2004