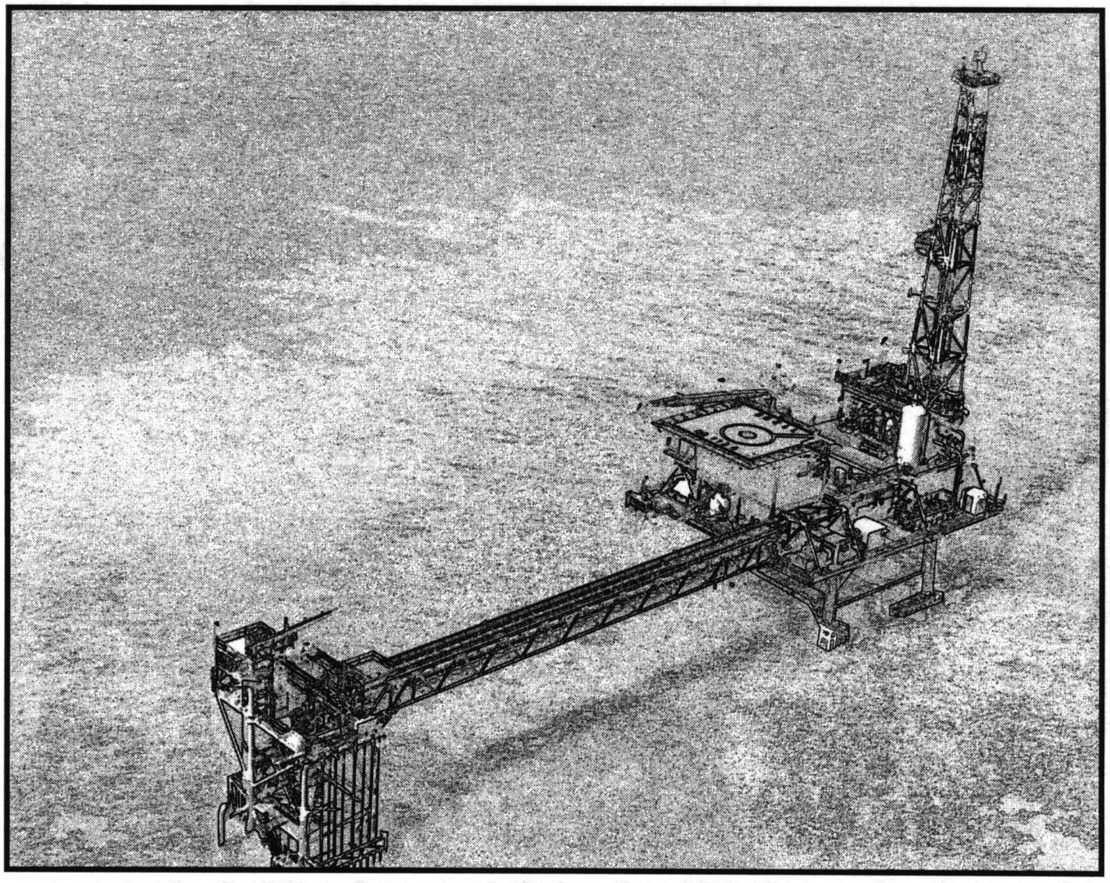
OCS Study
MMS 99-0031

History of Coastal Alabama Natural Gas Exploration and Development: Final Report



MMS U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

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MMS 99-0031

History of Coastal Alabama Natural Gas Exploration and Development: Final Report

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COVER PHOTOGRAPH

Cover photo of Platform 113a at Fairway Field, Offshore Alabama, is courtesy of Shell Offshore, Inc., an affiliate of Shell Oil Company.

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EXECUTIVE SUMMARY

Mobil Oil Company leased four tracts in lower Mobile Bay from the State of Alabama on October 24, 1969, for $78,822 with a 1/6th royalty. Following issuance of the leases, Mobil filed an application to drill a well to 16,500 feet on July 9, 1970, with a Smackover target in mind. Mobil endured a lengthy delay before obtaining approval to proceed with an exploratory drilling program. The permit was not signed until June 21, 1978—after two federal and one state court appearances by Mobil and posting a $55 million bond. The first well was spudded in tract 76 on November 17, 1978—nine years after the award of leases. The nine year regulatory delay and ultimate success make one marvel about what Mobil geologists and management knew that induced Mobil to maintain a nine year regulatory siege. The leases were a bargain; the permits were not.

The Attorney General of Alabama expressed great concern about the need to protect Mobile Bay and the Mississippi Sound from exploration and development of hydrocarbons. The conflict was ultimately resolved when Mobil proposed to drill with no discharges of any kind; the zero discharge policy continues to govern Mobile Bay operations. The oyster fishery remains healthy.

Norphlet Discovery at the Apex of the *Energy Crisis*

Mobil's first well encountered natural gas and tested 12.2 MMCFD at a total depth of 21,113 feet November 28, 1979, having discovered Norphlet formation gas—a mile below the top of the Smackover formation. At the apex of the Carter Administration's *Energy Crisis*, Mobil had discovered a giant gas field in 14 feet of water in America's back yard—not in some remote, politically unstable country, harsh environment, or 2,000+ feet of water. The prospect of $9 per MCF gas after the NGPA passed in 1978 and the Norphlet geology were extraordinarily exciting to petroleum industry professionals, who recognized the potential for discovery of other very large natural gas accumulations.

By 1981, prices for Norphlet production covered by NGPA Section 107 deep gas ranged between $7 and $9 per MCF. Mobil's Norphlet gas reserves had become a treasure beyond anyone's expectation years earlier when they applied for the exploration permit. Unfortunately, the "gas bubble" dropped prices below $2 MCF by the time Mobil's, Shell's and Exxon's production ultimately came on line. Even finding markets became a challenge unforeseen when bidding and exploration occurred.

Lease Sale Bonanza

Exxon's bids at the 1981 State of Alabama Lease Sale and the 1982 Federal Lease Sale reveal that they bet heavily on Norphlet geology and high gas prices. Exxon submitted high bids of $255.9 million for seven of the 13 tracts awarded by the State of Alabama following the 1981 sale. The industry bid on 35 tracts, but the state rejected bids for 22 tracts: with nearly $450 million in the bank—more than ever imagined—the state simply rejected bids below $2,000 an acre. "We've struck oil," a jubilant Governor Fob James quipped after the bonuses were counted.

Between 1981 and 1984 Alabama leased tracts in state waters for bids totaling $800 million. MMS leased tracts in federal Mobile Bay OCS waters between 1982 and 1985 for bids totaling $562 million—$1.36 billion combined. Governor James subsequently agreed with the legislature to set up a perpetual trust fund to ensure that the State of Alabama would continue to benefit from the interest on the bonus proceeds. At the end of FY 1996, the balance of Alabama's trust funds had grown to $1.35 billion, having increased with the receipt of state royalty payments and the state's 27 percent share of 8(g) federal royalty payments from producing federal leases within eight miles of Alabama shoreline.

Annual interest from the funds has averaged about $100 million since 1986. The interest is transferred into the state's General Fund, where it amounts to between 11 - 12 percent of the state's General Fund budget. The trust funds and interest earnings will continue to grow so long as gas is produced from state and nearby federal waters. Substantial increases in state production and federal production in 8(g) waters during 1997 and 1998 will increase Alabama royalty collections.

High Exploration Success Rate

Seventeen Norphlet wells were spudded between 1981 and 1984, 13 of which became gas discoveries—an extraordinary accomplishment before 3D seismic. Besides Mobil's Mary Ann discovery, three state Norphlet discoveries and one federal Norphlet discovery subsequently became development projects based on discoveries before year end 1984.

Through year end 1997, 75 Norphlet wells have been drilled in state and federal waters off Coastal Alabama—28 exploration, the balance delineation and development wells. These wells discovered 20 gas fields. Twenty Norphlet discoveries for 28 exploration wells represents a 71 percent success ratio. All but three of discovered fields are producing gas. Mobil abandoned the West Dauphin Island Field as uneconomic. Exxon maintains its 867 Field lease and plans to produce it in 1998. Chevron and its partners, Conoco and Murphy, have filed a Development and Production Plan to develop Destin Dome. Exxon has drilled the most wells, 20; Mobil has drilled 19.

Mobil amended its original application to change the target from 16,500 to 21,500 feet—changing the target from Smackover to Norphlet—two years after the original application. One wonders what would have happened if Mobil had drilled to Smackover at 16,500 feet in 1970. Mobil's decision to drill below the Smackover to the Norphlet in their original exploration of Lower Mobile Bay has been a bonanza for State of Alabama coffers and American consumers, even if the prices received for the gas have been sharply lower than operators anticipated. The Coastal Alabama/Panhandle Florida Norphlet trend is one of the most important U. S. gas producing regions.

Norphlet Development Challenges

Norphlet gas is a hot, sour, high pressure, corrosive mixture of methane, hydrogen sulfide, carbon dioxide, and free water. Dealing with it is difficult, dangerous and expensive. Development requires an integrated system involving specialized technologies for production, dehydration, pipelines and processing. Over $4 billion has been spent since the early 1980s installing these systems and drilling wells in addition to nearly $1.5 billion in bonus payments to acquire the leases. Mobil, Exxon, and Shell constructed sour gas processing plants onshore Mobile County. BP, first, and subsequently Union and Chevron, decided to process Norphlet gas on the platform, shipping market-quality gas to shore. Shell alone transports corrosive wet gas to shore for dehydration and processing at the Yellowhammer Plant, relying on a proprietary corrosion inhibitor compound Shell developed in lieu of water separation on the platform.

The frontier nature of the Norphlet geology and the associated production engineering and technology challenges in many ways parallel the equally daunting but different challenges of Alaska's harsh, remote locale. Only a few of the major oil and gas companies could afford the billions of dollars and years of lead times necessary to bring the Norphlet into production. The Mary Ann Field began production in 1988—nine years from first discovery to first production. Shell's Fairway Field started up in late 1991 along with Mobil's federal 823 Field—ten years after the lease sales. BP brought its 821/109 Field online in early 1992 and Exxon started its three fields in late 1993—12 years after the 1981 lease sale. Beyond Mobil's initial regulatory siege, no significant regulatory delays factor into these development schedules.

Chevron, Mobil and Spirit Energy (Union) have dominated 1996-1997 development activity. Mobil's well 95-5, on the southern edge of its tract adjoining Exxon's producing North Central Gulf Field, came online November 1996 and produced as much as 70 MMCFD for several months before reducing production to a sustainable 50 MMCFD. Mobil's newest producing well in the OCS is 869-3; this well produced 85 MMCFD in March 1997. These two wells represent a new generation of technology using large-diameter production tubing.

Union and Chevron have been developing the eastern and western edges of the Mobile Bay OCS in their 820, 904 and 916 Units. Chevron took nine years from its first Norphlet discovery in OCS 861 in 1985 to first production in 1994. Union was able to bring its 904 Field to production in a little over five years, discovering the 904 Field in 1988 and starting production in 1993. But the well (904-1) failed due to mechanical problems. The field only came back into production three years after the first well, in December 1996 with 904-2.

Mechanical and completion problems have plagued most of the operators. Production has been reduced due to plugging, scaling and water intrusion. Total gas production would have been greater sooner but for these problems. At least 150 MMCFD of production was lost during 1996 and 1997 from failed wells and wells that are only limping along in comparison to start-up rates. Keeping Norphlet wells producing at design rates is as difficult as finding the reservoirs four miles beneath the surface.

Thumbnail company performance in the Norphlet is compared on Table X.1, which shows summary information on leasing, exploration success, and production success. The primary objective of this report is to assemble the data summarized on Table X.1. The following observations can be drawn from the table, which does not take into account time values of money.

- Exxon acquired two to three times the acreage of its early 80s bidding competitors, Mobil and Shell, and spent 2.4 to 5.0 times as much.

- Exxon paid 26 percent more per acre than Mobil; 56 percent more than Shell.

- Union and Chevron, entering the game after energy prices came down, acquired large acreage at greatly less per acre—$588 - $645. This amounts to an average of $0.16 for each of Exxon's bonus dollars.

- Acreage is only real estate; discovered reserves matter. While recognizing the speculative nature of discovered reserves, Mobil has tallied 4.7 TCF to Exxon's 3.7 TCF GIP.

- Mobil's discovered reserves cost five cents per MCF, one-third of Exxon's 15-cent reserves. Chevron has done second best at finding reserves—six cents per MCF.

- Producing reserves creates cash flows and Mobil has produced the most gas at year end, 1997—655 BCF, 24 percent more than Exxon. Mobil started production first, 1988, compared to Exxon, which only started production in 1993.

- Shell has produced the most gas per well drilled, 52.9 BCF, twice Exxon's recovery per well. Company strategies toward size of the entire production complex importantly govern recovery per well differences among Exxon, Mobil and Shell. Problem wells and later start-ups govern Union's and Chevron's low recovery per well.

- Chevron's and Union's 1995 start-ups partially account for the much lower cumulative production at year end 1997. Their seven P&A'd, shut-in and constrained producing wells mostly accounts for low cumulative production and average production per well. Keeping wells producing matters to Norphlet economics.

- Shell's average bonus per produced MCF, $0.31, is lowest among the operators. Shell has produced 42 percent of discovered gas compared to high bonus cost per MCF producers, Exxon and Chevron, which have produced only 14 and 4 percent of the discovered GIP.

- Remaining discovered reserves show that all but Shell will be producing Norphlet for many years into the future. Shell's Fairway Field R/P ranges from 4 to 8 years.

Table X.1
Coastal Alabama Norphlet Production Indicators

Company	Bonus Payments	Acreage Leased	Discovered Reserves (GIP)	Cumulative Production 12/97	Wells Drilled 12/97	Average Production Per Well	Average Bonus per Acre	Average Bonus per Reserves	Average Bonus per Cum Prod.	Remaining Discovered Reserves
Unit of Measure	($1000)	(1000)	BCF	BCF	#	(BCF)	($/acre)	($/MCF)	($/MCF)	%
Exxon	$573,040	147.6	3720	529.9	20	26.5	$3,882	$0.15	$1.08	86%
Mobil	$242,493	78.6	4725	655.1	19	34.5	$3,086	$0.05	$0.37	86%
Shell	$116,114	46.7	880	370.1	7	52.9	$2,487	$0.13	$0.31	58%
Union et al	$72,219	111.9	885	85	7	12.1	$645	$0.08	$0.85	90%
Chevron et al	$73,097	124.3	1185	41.5	15	2.8	$588	$0.06	$1.76	96%

Notes:
1. Mobil includes Texaco tract 869.
2. Shell includes BP tract 821.
3. Chevron includes Tenneco tracts 863 and 864, and Texaco tract 872.
3. Discovered Reserves from Section 6 Appendix.
4. Cumulative Production from Tables 6.13 & 6.14.
5. Bonus Payments & Acreage from Table 3.8.
6. Wells from Table 4.10.

Production and Forecast

Coastal Alabama natural gas production surpassed 1 BCFD for the first time in February 1997, and averaged 1.02 BCFD for the year, or 371 BCF--18 percent more than 1996 production of 864 MMCFD Norphlet gas. Forty Norphlet wells produced 1.1 BCFD in February, 1998, in 17 Norphlet fields in Coastal Alabama. The expansion of Chevron's 820 and 864 Fields by two producing wells (819-1 and 864-4), Exxon's start-up of its 114-3 well, Shell's workover of well 113-3, and Mobil's drilling wells 823-A5 and 914-4 will likely sharply increase production from Coastal Alabama fields by winter 1998—if no other wells encounter production problems.

Four to six Norphlet new wells have been drilled annually in every year of the 1990s. Currently drilling and planned wells for 1998 - 2000 will maintain that average. Fifteen new Norphlet wells may add to production by year end 2000. These include temporarily abandoned wells awaiting either start-up, completion or a production decision; wells drilling at year end and planned to spud; and wells being worked-over to correct mechanical problems such as scaling. All of these wells are either field expansion wells, replacements for problem wells or wells to maintain production.

Forthcoming and planned wells will increase utilization of the sour gas processing capacity. Operators used 72 percent of existing processing plant capacity of 1.5 BCFD during fourth quarter, 1997. Planned activities appear matched to capacity, assuming that gas from some fields is shifted to other operators' plants to make the best use of facilities and capacity. For instance, Chevron processes its higher than anticipated H_2S well 863-3 in Shell's Yellowhammer plant; part of Exxon's gas is processed in Mobil's 823 plant.

Coastal Alabama Norphlet and Miocene production will rise to 1.4 BCFD by 2000. Destin Dome's production comes online after Mobile Bay production from discovered reserves reaches peak, thereby sustaining supplies to interstate markets in the 1.4 - 1.6 BCFD through 2005. Combining both the Alabama state and federal OCS offshore production, the Alabama-Destin Dome production forecast reaches and sustains 1.6 BCFD between 2002 - 2004, as shown on Figure X.1.

Cumulative production for the forecast totals about 9 TCF of Norphlet and Miocene gas by 2015. Total discovered gas in place is estimated to exceed 10.5 TCF, with ultimate recovery unknown. No one yet has produced a Norphlet reservoir to economic limit. Shell's Fairway Field evidences significant decline. Shell, uniquely, produced the field at reservoir limits and has extracted a much larger percentage of gas in place than any other operator to date. The other producers are facilities-constrained, having designed capacities to maintain nearly flat production longer.

Norphlet Overcame Every Risk

The Norphlet history mirrors the history of the petroleum industry. From halcyon beginnings, a hand-full of major oil and gas producers overcame regulatory risk, geology risk, technology risk, market risk, and price risk to develop a major domestic energy province. Mobil watched gas prices shoot up from $0.25 per MCF in 1969 to $9.00 when they spudded its first well, only to discover that its market had disappeared by 1987 when they were ready to produce. Chevron found very low cost reserves, but has been beset with problems keeping the wells producing as designed. While gas prices will never see forecast levels that influenced Exxon's initial excitement about Norphlet, Exxon, like other operators, has cut costs to match $2.00 gas and continues to develop the Norphlet. Geology, not being politically influenced, suggests that substantial Norphlet potential extends east of the Florida-Alabama state line.

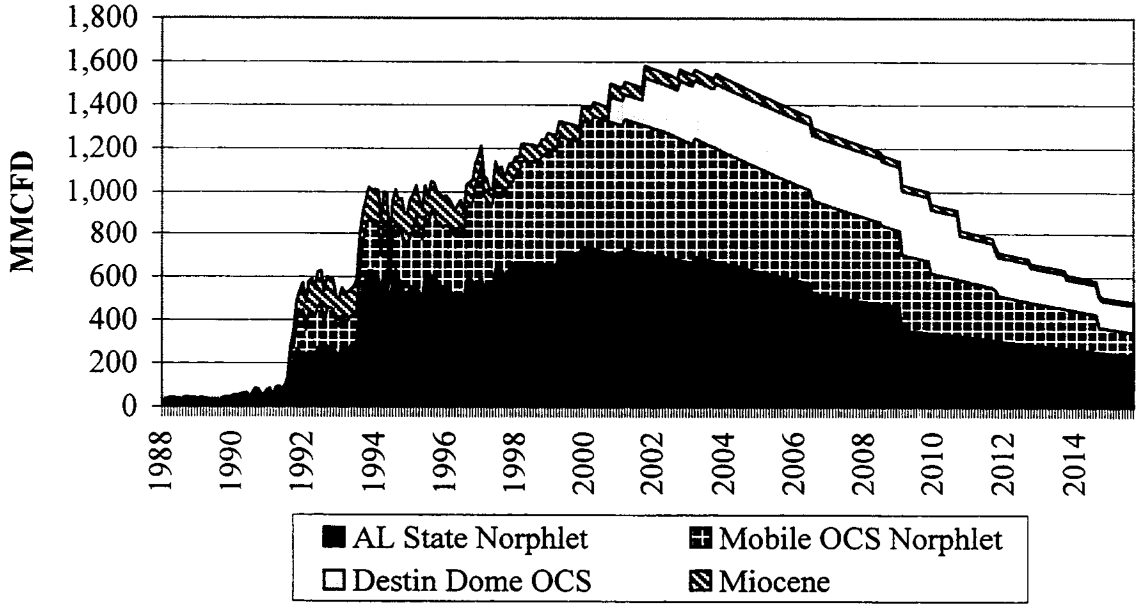

Figure X.1. Mobile Bay Offshore Gas Production History and Forecast

Source: Foster Associates, 1998.

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1.0 Mobil's Dogged Persistence Led to Norphlet Discovery

Mobil Oil Company leased four tracts in lower Mobile Bay (76, 77, 94 & 95) from the State of Alabama on October 24, 1969 for a term of five years. Figure 1.1 shows the location of Mobil's original tracts. Bonus payment for the tracts totaling 19,695 acres was $78,822 with a 1/6th royalty. Following issuance of the leases, Mobil endured a lengthy delay before obtaining approval to proceed with an exploratory drilling program. The Alabama Oil and Gas Board (AOGB) permit was not signed until June 21, 1978—after two federal court appearances by Mobil, one in state court, and the posting of a $55 million bond. The first well was spudded in tract 76 on November 17, 1978—nine years later.

Mobil was not the first lease holder of the tracks. During the 50s and 60s, tract 94 had been leased three times prior to Mobil, and tracts 95, 76 and 77 had been leased twice before. Pioneer Oil Company held the leases on the four tracts until they expired, July 1969. None of the tracts had been drilled. Mobil was the first to seek a permit to drill them. The subsequent nine year regulatory delay and ultimate success makes one marvel about what Mobil geologists and management knew that induced Mobil to maintain what became a nine year regulatory siege. "Mobil's dogged pursuit of an exploration/development project . . . [required] patience and an unswerving belief in a prospect," wrote the Oil and Gas Journal (OGJ).[1] The leases were a bargain; the permits were not.

1.1 The 1970s Regulatory Delay

Mobil filed an application with the AOGB for a permit to drill a well to 16,500 feet on one of the four tracts on July 9, 1970, with a Smackover target in mind. Mobil filed a second application for a permit to drill wells and erect structures with the Corps of Engineers (COE) on July 17. Mobil's proposed exploration came soon after the unfortunate 1969 Santa Barbara California oil spill. Sensitivity to protecting offshore and estuarine resources and beaches was very high. "Regulators shifted into a new higher gear, feeling the scrutiny and pressure of environmental organizations."[2] Governor Albert Brewer wrote to Mobil that he wanted "to make certain that Alabama has taken every precaution to prevent major oil spills in our waters." He requested the Oil and Gas Board Supervisor to form a study group to "review Alabama's present rules, regulations and laws governing offshore drilling and production and make recommendations deemed necessary to assure the very best system will be utilized by this State."[3]

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[1]Oil and Gas Journal, "Mobil has first Mobile Bay production in sight," June 30, 1986, p. 36.

[2]Tom Joiner, "The Significance of Alabama's Offshore Natural Gas Production," Speech to AOGB 50th Anniversary Reception, September 22, 1994.

[3]Quoted materials from a timeline provided by Alabama Petroleum Council, February 1997.

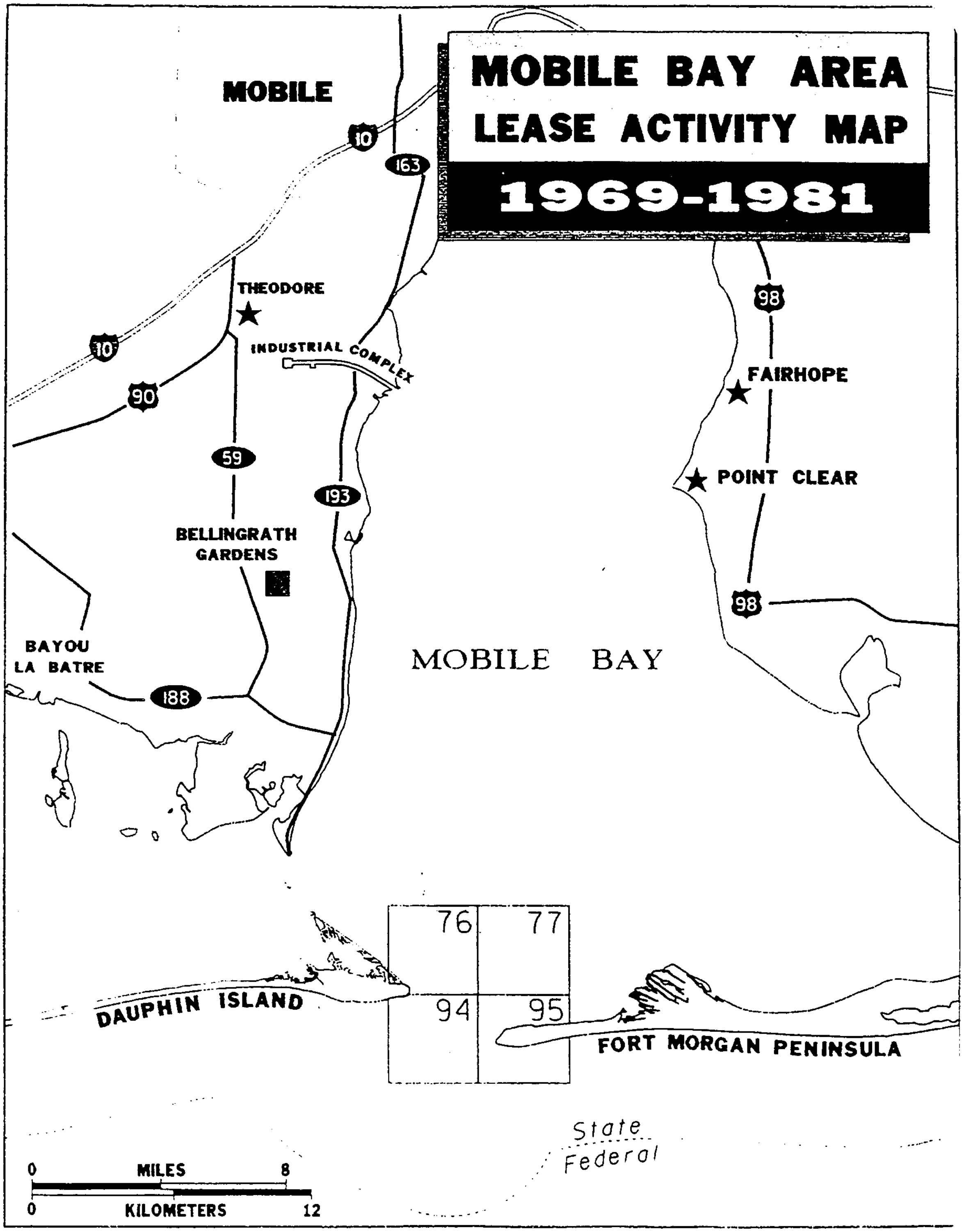

Figure 1.1. Mobile Bay Area Lease Activity Map, 1969-1981.

Source: MOEPSI, 1997.

1.1.1 Drilling Opposition Emerges

The Governor's Offshore Study Committee composed of 17 individuals from AOGB staff, wildlife groups, industry, plus state and federal agencies was formed in late July 1970 and began work to formulate reasonable rules and regulations. The following March 26, 1971, the Committee, under the direction of State Oil and Gas Supervisor P. E. LaMoreaux, presented its recommendations and proposed rules to Governor George Wallace. These were largely based on the Department of the Interior's rules for the OCS, and were called by observers "some of the toughest in the world."[4] Drafting the rules turned out to be the easy part; the challenge became getting them adopted.

During the rest of 1971, various state and Mobil officials met to discuss the proposed rules; they were not adopted and no permit was issued. On October 13, 1971—two years after the original application—Mobil amended its original permit request to change the target from 16,500 to 21,500 feet. Mobil changed the target from Smackover to Norphlet. Makes you wonder what would have happened if Mobil had drilled to Smackover at 16,500 feet in 1970.

State Attorney General Bill Baxley emerged as the leader of opposition to drilling on January 10, 1972. Mr. Baxley asked the COE to deny the permit for proposed drilling in Mobile Bay. Relying on information provided to him by the Audubon Society,[5] Mr. Baxley told reporters that "the seafood, wildlife and recreational resources of Mobile Bay are at least as valuable to the people of Alabama as are possible oil reserves . . . that oil wells in Mobile Bay would pose an unacceptable risk to the ecology of the bay . . . that a runaway oil well would spell ecological disaster for Mobile Bay."[6] Attorney General Baxley urged the state to give Mobil its money back.

Industry representatives, led by Mobil's Ed Bell, General Manager for Exploration and Production, who was responsible for Mobile Bay exploration, provided information on drilling safeguards in meetings. Mr. Baxley, in concert with Assistant Attorney General Henry Caddell, Chief of the Environmental Protection Division, turned a deaf ear on the industry's position. Mr. Baxley, having received numerous letters of support "should he decide to run for governor," had tapped into a politically popular issue. The fight was drawn. The Mobile *Press Register* weighed-in with an editorial describing the 30-year old Baxley as "the young gentleman who already has gone far in the field of state politics, [now] climbing on the bandwagon occupied by

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[4]"Oil, Gas Board to Hold Proposed Rules Hearing," undated news clip, 1972 Alabama newspaper.

[5]Henry Caddell, Letter to William Wade, March 17, 1997.

[6]"Bay oil drilling block asked," Birmingham *Post-Herald*, January 11, 1972.

zealous environmentalists."[7] But for Mobil's persistence, the Norphlet offshore may never have been discovered.[8]

Hearings were set on the proposed rules by the AOGB on August 30-31, 1972 in Mobile. The Hearings became so extensive that they spilled-over to September 26 and October 24. AOGB spokesperson Boyd Bailey summarized the proposed rules emphasizing their "toughness." Mr. Caddell, representing the Attorney General, stood firm on Mr. Baxley's "absolute prohibition" position and Mr. Ed Bell, representing Mobil, provided industry's position. The meetings introduced outspoken interveners to drilling from Fairhope, Save Our Bay, who preferred to be called the "SOBs." Mrs. Myrt Jones, President of the Mobile Bay Audubon Society, became and remains an outspoken advocate for environmental positions. A professor of Coastal Geomorphology from the University of California at Santa Barbara, Dr. Norman Sanders, delivered lengthy testimony about spills in the Gulf of Mexico, claiming that "Red Adair would be on welfare . . . if oil well drilling technology was as well developed as the oil companies say."[9] The decision to adopt the proposed rules was delayed and pushed up to the Governor.

In early June 1972, Mobil, concerned that it was three years into its five year lease term, requested the Director of the Alabama Department of Conservation (DOC) to suspend Mobil's lease obligations from July 9, 1970 until the permits were issued. This was denied June 26, 1972 on the basis of Attorney General Baxley's opinion that the "State does not have the authority to suspend these obligations at the present time." House Speaker Sage Lyons commented that "the Attorney General has made a political decision that he does not feel that there should be any drilling in Alabama offshore, regardless of the standards of safety and regulations imposed."[10]

1.1.2 Lawsuits, Negotiations and Settlement

Mobil filed a lawsuit in federal court on August 9, 1972 (Mobil v. Claude Kelly, Director of the Department of Conservation, et. al., C.A. No. 7277-72-P, U. S. District Court, Southern District of Alabama) seeking (among other relief) a decree that Mobil was entitled to have the primary terms of the leases extended by a period of time equal to the period from July 9, 1970 until the AOGB and the COE issued valid permits. This was resolved in Mobil's favor on January 11, 1973 when the federal district court entered a decision that subsequently extended the period of the leases by four years and 76 days after the AOGB issued a valid permit.

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[7] "Baxley's Negative Stand on Oil," Mobile *Press*, January 12, 1972.

[8] Tom Joiner, "The Significance of Alabama's Offshore Natural Gas Production," Speech to AOGB 50th Anniversary Reception, September 22 1994.

[9] Norman K. Sanders, " Hazards of Offshore Oil Drilling Operations," Before the Alabama Oil and Gas Board, Mobile, Alabama, October 24, 1972.

[10] AP News Analysis, Phil Oramous, July 13, 1972.

AWIC Flip-Flops

New rules and regulations governing drilling, producing and pipeline operations finally were adopted by the AOGB on January 26, 1973. Mobil then initiated an Environmental Impact Report (EIR) which went to hearings two and a half years later, in October 1975. The Alabama Water Improvement Commission (AWIC) voted in December to certify Mobil's project to drill one test well pursuant to Section 401 of the Federal Water Pollution Control Act. But this wasn't the final decision.

The Attorney General's office argued to state agencies that the state should have a single cohesive position. Dr. Robert Boucher, one of the members of AWIC and Dean of the Medical School of the University of South Alabama, moved his home to Dauphin Island about 1975 and became concerned about evacuation of the island in the event of a gas blow-out.[11] AWIC met again in February 1976 and rescinded the earlier certification to reconsider the permit because it feared pollution of Mobile Bay. Dr. Boucher's concerns and the Attorney General's position had an effect on AWIC's February 1976 reversal.[12]

Mobil quickly filed an application for rehearing and a special hearing occurred in April 1976, at which Mobil presented extensive testimony. On May 28, AWIC affirmed its earlier decision to deny certification. Mobil went back to court.

Back to Court

The following month Mobil filed an amended complaint in its case in federal court seeking an injunction against AWIC. The Alabama Attorney General filed to contend that state court, not federal, had jurisdiction, and in December 1976, federal court declined to assert jurisdiction. Mobil re-filed in state court in January 1977. The case appeared to be headed to an April 10, 1977 trial date.

Zero Discharge Policy—Settlement Agreement

Settlement talks emerged. From January 1977 to March 1978, Mobil and AWIC engaged in settlement negotiations, which included Mrs. Myrt Jones of the Audubon Society. Great concern was expressed about the need to protect oyster beds on the southwest shore of Mobile Bay and in Mississippi Sound. Mobil proposed to drill with no discharges of any kind. This became the zero discharge policy that continues to govern Mobile Bay operations. Nothing goes overboard. No drill cuttings, mud or wastewater may be discharged in Mobile Bay. No galley waste, sanitary waste or cooling water waste may be discharged. A public hearing was held in February 1978 and shortly thereafter Mobil, AWIC and other parties signed a Settlement Agreement. A Mobil spokesperson described the rules at the time as "the most stringent ever

[11]Henry Caddell March 17 letter to William Wade.

[12]Telcon with Craig Kneisel, Assistant Attorney General, State of Alabama, April 15, 1997. Mr. Kneisel was General Counsel for AWIC at the time and worked with Mr. Caddell from the A.G.'s office.

adopted by any state—much stiffer than federal rules."[13] The COE permit was issued on May 18, 1978; Mr. Tom Joiner, Supervisor of AOGB, signed its permit on June 21, 1978. Mobil filed for a permit to drill four appraisal wells in Mobile Bay on October 26, and spudded Well 76-1 on November 17, 1978, about one mile northeast of Dauphin Island. Mobil Oil Exploration and Production Southeast, Inc (MOEPSI) was formed December 12, 1978 to take charge of the activity under Mr. Ken Keller, its first president. Mr. Keller had replaced Mr. Ed Bell as General Manager in 1976.

Two key differences set the Settlement Agreement apart from the AOGB 1973-adopted regulations:

- The zero discharge policy, and
- The $55 million bond that MOEPSI was required to assure.

Mr. Caddell, who worked closely with Mr. Baxley to urge the safeguards in place today, wrote in March 1997, "There has been a very extensive amount of drilling. I am convinced that, if they had been allowed to discharge drilling fluids, the quality of our estuary and waters would be quite different today—with more degradation."[14] Hart's *Oil and Gas World* claimed that the gas industry has had less impact on the waters of Mobile Bay than a small power boat.[15] The oyster fishery remains healthy.

1.2 Exploration Success and Continued Regulatory Initiatives

A month after Well 76-1 was spudded, the COE determined that an EIR for the appraisal program would be required. Because of the delays in the exploration permit, MOEPSI initiated the EIR right away. This led to extensive development of environmental information over 1979 and 1980, and culminated with a Draft EIR on August 15, 1980. Mobil's first well encountered natural gas and was tested at a total depth of 21,113 feet November 28, 1979, having discovered the Norphlet formation gas—a mile below the original Smackover target.

Numerous problems beset MOEPSI's drilling including Hurricane Frederic whose eye passed directly over the drilling rig without inflicting damage before it moved on and knocked out the bridge to Dauphin Island a mile to the west of the drilling rig. The final cost of the well totalled $20 million—$13 million above Mobil's 1978 cost estimate. Ultimately drilling wells to four miles beneath the surface of the earth has proven to be difficult and costly. Twenty million dollars remains the benchmark in 1997 for drilling a Norphlet well. Some have cost twice that.

[13]OGJ, "Mobile Bay Permit may come this fall," April 23, 1978, p. 34.

[14]Henry Caddell March 17 letter to William Wade.

[15]Harts Oil and Gas World, "Mobile Bay operators bring more gas into production at high rates, high costs," April, 1995, p. 28-29.

1.2.1 The Norphlet! A Remarkable Discovery

The subsequently named Lower Mobile Bay-Mary Ann Field was the first offshore Jurassic discovery in the northern Gulf of Mexico, significantly extending the area of known onshore Jurassic production at Hatter's Pond, 50 miles north of the Mary Ann field, and the Flomaton field, 40 miles northeast of tract 76 in Escambia County, Alabama. The productive interval tested November 28 - 29, 1979 revealed 283 feet of net pay with as much as 20 percent porosity and 1 milli-darcy of permeability. Mobil Chief Geologist Roy Roadifer later termed the discovery "remarkable" at a 1986 AAPG meeting in Atlanta.[16] John McCaslin, Exploration Editor of the OGJ, described the net pay as "awesome," with 6,000 acres of productive formation and average pay thickness of 100 feet.[17] The gas tested 5 percent carbon dioxide and 9 percent hydrogen sulfide—sour, corrosive gas—thereby creating a significant challenge in the development plan.

MOEPSI spent 1980 working on the EIR and ocean dumping permit issues while further exploration stood still. On November 7, 1980 MOEPSI petitioned the AOGB to name their discovered field the Lower Mobile Bay Field, define the Norphlet Gas Pool and establish Special Field Rules.[18] Figures 1.2 and 1.3 were submitted as exhibits to show the location of the field and the contours of the Norphlet structure. Mr. F. T. Musson and Mr. Joseph B. Fryer appeared as MOEPSI's witnesses presented by attorneys Dewitt Reams and Bob Jorden. Mr. Fryer identified himself as a geologist who had worked on the project since 1969; he must have been the person who believed in the potential of the offshore Jurassic. Figure 1.2 shows the location of the discovery well in the southeast area of tract 76 along with the planned locations of two appraisal wells in tract 94, and one each in tracts 77 and 95. A single norphlet gas pool underlay all four of the tracts. This is visible on Figure 1.3, a seismic structure map that shows the discovery well virtually in the center of the reservoir. AOGB Order 80-209 named and defined the Lower Mobile Bay Field.

1.2.2 Lower Mobile Bay Field Drilling Begins

Following final approvals from the Corps and AOGB in late January 1981, Rowan 004 and Penrod 65 drilling rigs moved into Mobile Bay. Mobil spudded two appraisal wells on tracts 94 and 95 in February 1981 and constructed an operations base in Bayou La Batre. Following another year of environmental research, the Mobile Bay Norphlet gas play finally gained momentum.

MOEPSI's two appraisal wells both tested Norphlet gas in the range of 21,000 feet: 94-2 on May 27, 1982; 95-1 on August 24, 1982. (Well 94-1 was permitted twice, but never drilled.

[16]OGJ, "Mobile has first Mobile Bay Production in sight," June 30, 1986, p.36.

[17]OGJ, "Mobil eyes new Norphlet test off Alabama," Jan 11 1988, p. 76.

[18]AOGB Docket 11-7-808. MOEPSI subsequently renamed the field Lower Mobile Bay-Mary Ann field in 1983, Docket 6-30-83, after the wife of Raleigh Warner, CEO Mobil Oil at the time. This is the only Alabama field that is not named after a geographic location.

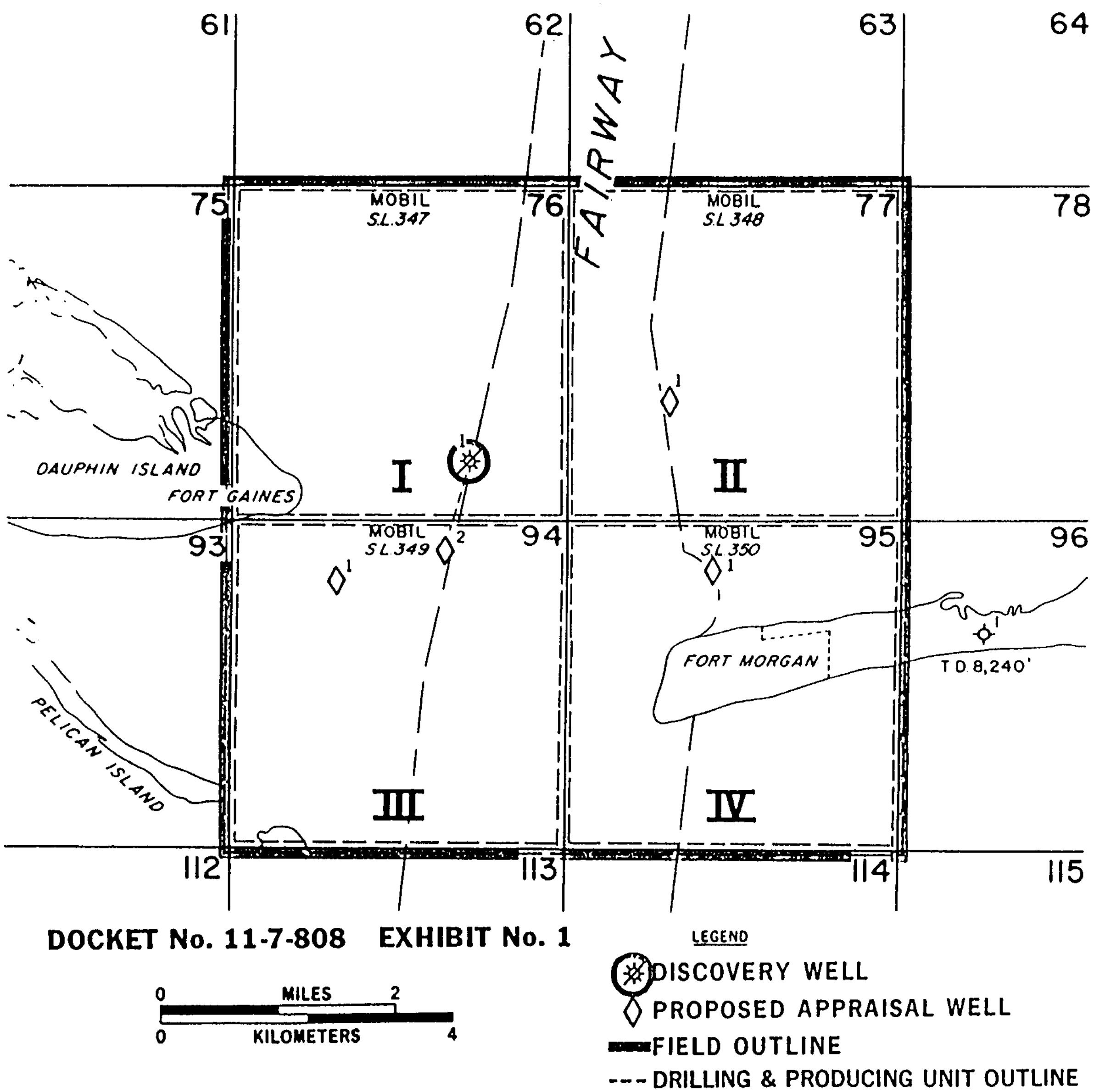

Figure 1.2. Lower Mobile Bay Field.

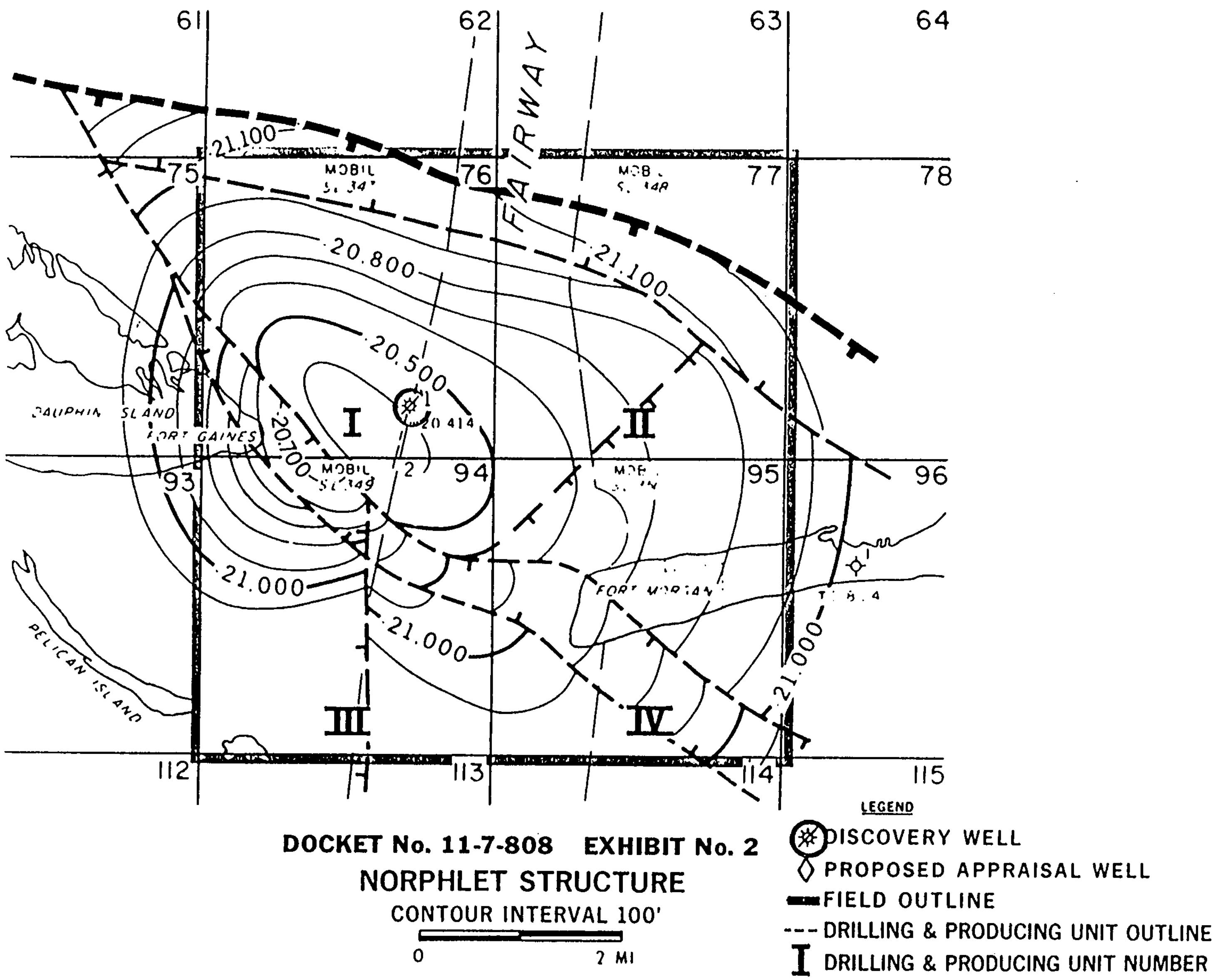

Figure 1.3. Lower Mobile Bay Field, Norphlet Structure.

94-2 was the first well drilled.) These wells required 15 and 18 months respectively to drill. Well 94-2 was drilled from the same surface location as the discovery well but was deviated to a bottom-hole location 4,600 south in tract 94. The deviation avoided the Mobile Bay shipping channel and eliminated a surface structure . The third well, 95-1, was drilled half a mile north of Fort Morgan. A fourth appraisal well, 77-1, about 2 miles north of Fort Morgan, was spudded July 17, 1982. This subsequently tested gas on March 28, 1983. Shallow well 95-2 into Miocene was successful on October 11, 1982. This was used as fuel for the subsequent platform. Well 76-2 quickly followed MOEPSI's successful Miocene well, spudding January 10, 1983. Well 77-2, the sixth Norphlet well, spudded on March 12, 1984. Both 76-2 and 77-2 were cored but not tested for gas until several years later. Mobil actually drilled six successful Norphlet wells producing between 10 and 26 MMCFD of gas between November 1978 and mid-1984—a remarkable exploration achievement in previously unexplored offshore Jurassic Norphlet. Table 1.1 lists the wells drilled to delineate the Mary Ann Field.

Table 1.1
Mary Ann Field Well Results

Well	Spud Date	Test Date	Depth	Test Results
76-1	11/17/78	11/28/79	21,113	12.2 MMCFD
94-2	2/27/81	5/27/82	21,859	15.5 MMCFD
95-1	2/1/81	8/24/82	20,935	10.5 MMCFD
77-1	7/17/82	3/28/83	20,984	19.4 MMCFD
95-2	9/18/82	10/11/82	2,750 (Miocene)	4.0 MMCFD
76-2	1/10/83	6/29/88	20,931	gas
77-2	3/12/84	8/13/87	21,710	gas

Source: AOGB

1.2.3 Illegal Discharges Threaten Continued 1982 Activity

During the course of drilling wells 94-2 and 95-1, contractors under MOEPSI's direct control were discovered in June 1982 discharging into Mobile Bay at night what was subsequently revealed to be water that had accumulated in the drilling mud barge.[19] This violated the "no discharge" policy. The Mobile Bay Venture Manager, Mr. F. D. Musson, received a phone call Friday, June 18 from an attorney, Mr. Jimmy Langford, who passed along an anonymous message that "a Mobil rig in Mobile Bay was observed to have turned its lights off at night and dumped liquid waste in the Bay." Mobil immediately looked into the allegation. "Early on Tuesday morning, June 29," Mr. Ken Keller, President of MOEPSI, subsequently testified,

[19] OGJ, "Discharges cloud action off Alabama," September 6, 1982, p. 56.

". . . I received verbal reports that I can best describe as shocking. . . . On at least one occasion in April 1982 water had been pumped into the Bay from the hopper barge which is based to collect the rig liquids and solids. We immediately on the same day reported the matter to [all appropriate state and federal agencies] . . . and issued a press release on July 1."[20]

Mr. Charles Gradick, the Attorney General who replaced Mr. Bill Baxley, AWIC, the U. S. Coast Guard, the AOGB, and Mobil itself immediately initiated investigations, along with the Audubon Society. Mobil retained its Mobile law firm Reams, Woods, Vollmer, et al to conduct an independent investigation. The firm brought in a retired FBI investigator, Mr. James A. Day, to interview drilling personnel.

MOEPSI President Ken Keller appeared before AWIC on July 12, 1982 and AOGB on July 30, 1982 and acknowledged that the discharges were not accidental and that they had occurred in the Bay "intermittently over a period of time between spring 1981 and June 1982 . . . generally at nights to avoid detection." The exact nature and quantify of the fluids was unknown, except that only water was intended to be released by the persons responsible for the improper discharge. Mr. Day's investigation revealed that motivation was apparently a "few individuals . . . trying to save time and money by sending less waste to the approved disposal sites." Mr. Keller stated that strict compliance was the company policy and that "policy and directives [had] been widely disseminated through all levels of the Mobil organization. . . . Virtually to the man . . . the [interviewed personnel] were well aware of the no discharge requirements." [21] Mr. Reams testified that the senior MOEPSI person knowledgeable was the drilling supervisor.[22] The most likely reason given by Mr. Keller for why the dumping occurred was that the drilling personnel, having worked mostly in the Gulf of Mexico, had never encountered such stringent requirements and simply ignored them because they believed them "simply unnecessary."

MOEPSI agreed to pay a fine of $2.0 million plus clean-up costs, which exceeded $500,000. OGJ wrote that "Mobil fired 15 employees and disciplined eight others who were involved in Mobile Bay drilling operations."[23] A MOEPSI management level person was directed to personally supervise drilling activities on the rig.

Swift actions by both the agencies and Mobil eliminated the problem, cleaned up the waters, and punished the guilty. MOEPSI was awaiting a COE decision on its production phase application at the time, which was delayed but subsequently issued. Exploration and development, which might otherwise have been stopped, resumed. Mobil executives today recollect that "Mr. Keller's swift action and emphatic response had a positive effect" in demonstrating to state

[20]Testimony of Mr. Kenneth Keller to Special Session of AOGB, July 30, 1982, p. 8 - 10.

[21]Testimony of Mr. Kenneth Keller to Special Session of AOGB, July 30, 1982, p. 10, 15 - 16.

[22]Testimony of Mr. Dewitt Reams to Special Session of AOGB, July 30, 1982, p. 45.

[23]OGJ, "Mobil to pay for Mobile Bay discharges," October 4, 1982, p. 46. Mobil confirmed that 17, in fact, were fired. Mobil Public Affairs telcon April 29, 1997.

regulators that they fully intended to operate within the "no discharge" and all other restrictions.[24]

The one black mark on the exploration effort had an inoculation effect on the industry. The natural gas industry has coexisted peacefully with the other resource-based industries in Coastal Alabama, including the booming tourism industry. Experiences among the other Coastal Alabama resource industries are described in Foster Associates "Case Studies" within "Social and Economic Consequences of Onshore OCS-Related Activities in Coastal Alabama, Economic Baseline of the Alabama Coastal Region," Draft March 1998.

[24]Telcon with Mike Kimmitt, Mobil Public Affairs, April 29, 1997.

2.0 Norphlet Geology & Vintage 1980 Price Forecasts

At perhaps the apex of the Carter Administration's *Energy Crisis*, MOEPSI had discovered a giant gas field in 14 feet of water in America's back yard—not in some remote, politically unstable country, harsh environment, or 2,000+ feet deep water. Both the prospect of $9.00 per MCF gas and the Norphlet geology that MOEPSI's 1979 discovery in Mobile Bay confirmed were extraordinarily exciting to petroleum industry professionals. Even with 2D seismic technology, explorationists other than MOEPSI's recognized immediately the potential for discovery of other very large natural gas reservoirs.

The bidding and bonuses seen in the 1981 State of Alabama and 1982 federal OCS Lease Sales make sense with an understanding of industry confidence about the hydrocarbon potential and the price outlook. Section 2.1 discusses the regional geologic setting that MOEPSI had discovered. Section 2.2 discusses gas price and gas market outlooks vintage 1980 - 1984.

2.1 Norphlet Geology and Reserve/Resource Estimates

The discovery of the Flomaton Field at 15,500 feet in Escambia County in 1968 marked Alabama's first discovered hydrocarbons from the Jurassic age Norphlet Formation, and extended the eastern limit of Jurassic production about 75 miles southeast of prior discoveries in Choctaw and Clarke Counties, Alabama. This discovery led to a period of intense leasing and drilling that resulted in the discovery of the Jay and Little Escambia Creek Fields onshore the Florida Panhandle.[25] Deep oil and gas exploration gained momentum in late 1974 when the large Hatter's Pond and Chunchula Smackover-Norphlet Fields were discovered at 18,120 feet in Mobile County, about 40 miles north of MOEPSI's ultimate discovery.

MOEPSI's 1979 deep Norphlet discovery, which is similar to the Flomaton reservoir in that the gas is trapped in a faulted salt-pillow structure overlain by tight, nonproductive Smackover,[26] confirmed what geologists had believed. Tom Joiner, Chief Geologist of the State of Alabama, wrote in 1980 that the "flank of the Wiggins-Conecuh trend and updip Smackover grainstones associated with salt structures are excellent areas for petroleum exploration in Southwest Alabama." The Wiggins arch sits between the Hatter's Pond Field and the Lower Mobile Bay Field. Joiner summed it up in 1980 with these words: "Discovery of the Lower Mobile Bay Field opened up a potentially very large hydrocarbon province."[27]

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[25]OGJ, "Leasing, drilling state and federal Alabama waters," April 22, 1985, p. 134 - 135.

[26]Marzano, Michael S., Glenn M. Pense and Peter Andronaco, "A look at the Norphlet in Mary Ann field," OGJ, March 6, 1989, p. 55.

[27]Joiner, Thomas, Markel Wyatt and John H. Massingill, "A Discussion of Oil and Gas Development in Southwest Alabama," State Oil and Gas Board, Report 6, 1980.

2.1.1 Coastal Alabama Petroleum Geology

More than 135 million years ago, during Jurassic times, Mobile Bay and Southwest Alabama was a desert adjacent to a shallow sea. The Appalachians, a very old range, were much higher than today. This mountain range was heavily eroded in Jurassic times and became distributed in the present day Coastal Alabama area as an extensive sand body--the Norphlet. Streams and rivers from the Appalachian mountains carried sediments from the eroding Appalachians far out into this desert. Prevailing winds from the north reworked and redeposited these sands forming the sand dunes and different sorts of sandstones found in the Norphlet. In addition to the eolian dunes, Norphlet deposits include fluvial, interdune (wadi) and marine sediments in the areas offshore Mississippi, Alabama, and Florida. Dramatically thicker Norphlet deposits occur in the Mobile Bay area and offshore the Florida Panhandle.[28] Chevron Senior (Norphlet) Geologist Gary Jacobs described "the ancient Norphlet desert [as] similar to today's Namibia along the west coast of Africa [with] towering sand dunes two- to four-hundred feed high, with much sand between the individual dunes. It was an entire eolian depositional system or "sand sea," not individual dunes accumulating regionally."[29]

These sand dune deposits have been discovered four miles deep as the Norphlet Formation. The eolian Norphlet Formation is found in a narrow band along the Mississippi, Alabama and Florida Panhandle coast. Norphlet reservoirs are characterized as wind-deposited dunes and interdune sandstones, which vary in thickness to more than 1000 feet. Productive Norphlet gas reservoirs can be extensive and thick. Gas pays can exceed 280 feet in thickness.

State of Alabama Geologist Ernest Mancini, with colleagues Robert Mink, Bennett Bearden and Richard Wilkerson wrote the first definitive article on the Norphlet geology.[30] They called the hydrocarbon potential of the Coastal Alabama area "excellent, with structural traps primarily involving salt anticlines, faulted salt anticlines and extensional fault traps associated with salt movement. Reservoir rocks consist primarily of quartz-rich eolian, wadi, and marine sandstones having principally secondary . . . porosity with some intergranular porosity."[31] The desert plain extends west to Mississippi but the area with perhaps the maximum dune development is Coastal Alabama.[32] In 1988, they described the Norphlet as "part of a deep Jurassic natural gas trend that extends across southern Mississippi and Alabama into the Gulf of Mexico. . . .

[28]Nat Turner and Gordon Fiedler, "Geophysical Interpretation of Jurassic Structures and Norphlet Deposition, Alabama State and Federal Waters," Seismic 4, 1985, p. 355 - 357.

[29]Gary Jacobs letter to Wade, July 23, 1997.

[30]Mancini, Ernest, Robert M. Mink, Bennett Bearden and Richard Wilkerson, "Norphlet Formation (Upper Jurassic) of Southwestern and Offshore Alabama: Environments of Deposition and Petroleum Geology," AAPG Bulletin, 69, 6, June, 1985, 881-898.

[31]Mancini, Mink, et al, 1985, p. 896.

[32]Mancini, Mink et al, 1985, p. 891.

The trend should continue from Alabama coastal waters . . . into the Pensacola and Destin Dome areas."[33]

The offshore Norphlet fields mostly produce from the eolian dune facies. The porosity of the sands tends to be higher in the federal fields, which average 14 percent, than in the state fields, which average 12 percent.[34] Another important facies in the offshore Norphlet is the presence of marine reworked sands at the top of the formation. This very low porosity zone is not considered productive and constitutes a waste zone, which where present, greatly improves recoverable reserve estimates. This zone ranges in thickness from zero to over 100 feet and is relatively unpredictable. Capping the Norphlet is a thin tight pyrite rich sandstone.

The natural gas in Norphlet reservoirs is found in generally northwest-southeast trending sand dunes. The primary trapping structural style is broad, low-relief, faulted, salt anticlines associated with small-scale growth faults. The seal for natural gas is generally a tight upper section of the Norphlet overlain by nonpermeable Smackover carbonates. The primary source of the natural gas is Smackover algal carbonate mudstones. Thermogenic dry methane gas produced as a result of thermal degradation of crude oil commonly is associated with hydrogen sulfide and carbon dioxide, which are present in all of the Norphlet discoveries.[35]

Subsequent to the Mancini, Mink et al papers, Mobil made available information developed by its research geology staff. The 1988 paper by Michael Marzano, Glenn Pense and Peter Andronaco added to the geologic knowledge of the Norphlet.[36] A subsequent paper by Tew, Mink et al summarized Norphlet regional geologic patterns that commonly accompany the presence of natural gas.[37]

Productive Norphlet natural gas reservoirs are found in anticlinal traps where there is a fortuitous combination of source rock. The mechanism of structure formation appears to be basinward salt flowage that formed large, broad and subtle anticlines, most of which are faulted. The seal for natural gas in the Norphlet is a generally tight section of the Norphlet in the upper part of the formation, overlain by lower Smackover carbonates which are also nonpermeable.

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[33]Mancini, Mink, Bearden and Hamilton, "A look at recoverable gas reserves in the Jurassic Norphlet formation off Alabama," OGJ, January 18, 1988, p. 62 - 64.

[34]U.S. DOI, Minerals Management Service, "Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs," Volume I, Table 4.

[35]Mancini, Mink, et al, 1988, p. 64.

[36]Marzano, Michael S., Glenn M. Pense, and Peter Andronaco, "A Comparison of the Jurassic Norphlet Formation in Mary Ann Field, Mobile Bay, Alabama, to Onshore Regional Norphlet Trends," Transactions—Gulf Coast Association of Geological Societies, XXXVIII, 1988, p. 85 - 100.

[37]Tew, Berry H., Robert M. Mink, Steven D. Mann, Bennett L. Bearde, and Ernest A. Mancini, "Geologic Framework of Norphlet and Pre-Norphlet Strata of the Onshore and Offshore Eastern Gulf of Mexico Area," AOGB Reprint Series 83, 1991, p. 596.

The majority of the Norphlet fields in the Mississippi, Alabama, Florida (MAFLA) region are found in the following geologic settings.

- Major basement highs affected sedimentation in the eastern Gulf—the Wiggins Arch complex, which includes the Baldwin High, the Conecuh Ridge, and Pensacola-Decatur Ridge in northwestern Florida.

- The best Norphlet facies are eolian sandstones that accumulated as thick dune, interdune, and marine sandstones.

- The key factor controlling hydrocarbon potential are areas that have thick accumulations of Louann Salt, characterized by salt-produced peripheral faults, salt-produced anticlines, and low relief domes.

Though unproductive at this time, potential undiscovered traps may be found where the Norphlet either thins or terminates over or against the basement highs, notably the Wiggins arch and the Pensacola-Decatur ridge complex. Regional stratigraphic and production data show that optimal reservoir sands and structures abound in the MAFLA region. AOGB Bulletin 140 concluded in 1991 that "the probability is high for numerous additional Norphlet fields" to be established in these areas.[38] Especially in federal waters, many low relief faulted salt cored anticlines remain to be tested to the east of discoveries offshore Coastal Alabama.

2.1.2 Alabama Waters Norphlet Reserve Estimates-1987

Mink, Hamilton, et al estimated recoverable reserves for sales gas (net of impurities, notably H_2S and CO_2) in Alabama state waters to range between 5.7 and 6.5 TCF in 1987.[39] The proved estimates shown on Table 2.1 represent reserves in reservoirs that had been penetrated by wells which provided significant geologic and engineering data by 1987. The potential reserves included natural gas that may be found in state waters in prospective reservoirs and in reservoirs that required further delineation. The 70 - 80 percent range shown on the table represents the amount of reserves in place assumed recoverable with existing technology and economic conditions.

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[38]Mink, Robert M., Berry Tew, Steven Mann, Bennett Bearden and Ernest Mancini, "Norphlet and Pre-Norphlet Geologic Framework of Alabama and Panhandle Florida Coastal Waters Area and Adjacent Federal Waters Area," AOGB Bulletin 140, 1990, p. 52.

[39]Mink, Robert M., Richard P. Hamilton, Bennett L. Bearden and Ernest A. Mancini, "Determination of Recoverable Natural Gas Reserves for the Alabama Coastal Waters Area," Oil and Gas Report 13, AOGB, 1987.

Table 2.1
Recoverable Sales Gas Reserves for Alabama Coastal Waters
(1987) TCF

Recovery Factors	70%	80%
Proven	3.65	4.17
Potential	2.06	2.35
Total	5.71	6.52

Source: AOGB, 1987.

2.1.3 Alabama and Federal Mobile OCS Reserve/Resource Estimates-1997

MMS and AOGB officials provided proved recoverable reserve estimates to Foster Associates for Norphlet fields. These are shown on Table 2.2. Assuming a 75 percent recovery factor, nearly 9.0 TCF of recoverable, marketable Norphlet gas has been discovered in state and federal leased areas. These reserves are tied to volumetric estimates of specific reservoirs. The estimates do not include more speculative notions of undiscovered reserves or potential resource estimates. The most uncertain aspect of these reserve estimates is the recovery factor. No one has any experience with ultimate recovery from Norphlet reservoirs. Judging by some of the problems operators have encountered with scaling and water intrusion, maintaining production in Norphlet wells is a risk beyond the usual geologic risks anticipated in recoverable reserve estimates. (Mechanical and water problems are discussed in Section 6.0.)

Achievement of the 75 percent recovery factor is clearly not certain. If the ultimate recovery is only 55 percent of gas in place, the discovered recoverable reserves drops to about 7 TCF and remaining reserves is about 4.8 TCF. At the 1997 average production rate of 1.0 BCFD, the reserve to production ratio (R/P) is between 13 - 19 years of remaining Norphlet production at 55-75 percent recovery.

Another speculative element of the reserve estimate is the OCS Destin Dome >1 TCF estimate. This only reflects Chevron's discovery. The Norphlet potential beyond that is not addressed in Table 2.2.

Table 2.2
Recoverable Sales Gas Reserves for Alabama Coastal Waters
(1997) TCF

	State	Mobile Bay OCS	Destin Dome OCS	Total
Recovery Factor	75%	75%	75%	75%
Proven	5.0	2.9	>1	>8.9
Cumulative Production, Year end, 1997	1.1	.6	0	1.7
Remaining Recoverable	3.9	2.3	>1	>7.2

Source: AOGB, 1997; USDI, MMS, 1997.

The Norphlet may yet become "another Prudhoe Bay," as Exxon Exploration V.P. Stephen M., Cassiani announced after the 1984 State Lease Sale. Norphlet reserve estimates by the Gas Research Institute in their 1996 projections, predict that discovered reserves in the Norphlet trend will reach 13 - 15 TCF between 2000 - 2005.[40] This estimate includes the entire Norphlet that extends east from Louisiana across Mississippi, Alabama and eastward beyond the OCS Destin Dome. While there will be continued drilling of known but unprobed Norphlet structures in Coastal Alabama and Mississippi between now and 2000, there is no other Norphlet leased acreage to drill to yield GRI's reserve estimate of twice that of Table 2.2 by 2005. Offshore Panhandle Florida may yet prove to fulfill GRI's prediction.

2.2 Gas Price Outlooks—Early 1980s—and Subsequent Market Developments

Since the 1954 Phillips case,[41] the U.S. natural gas market has exhibited substantial price variations primarily caused by changes in macroeconomic growth, interfuel competition (primarily from fuel oil), and federal price regulations. One of the high price outlook periods stemmed from the passage of the Natural Gas Policy Act (NGPA) of 1978 and lasted until about 1982. During this brief period the State of Alabama was fortunate enough to conduct its first offshore lease sale in March 1981, and MMS conducted Lease Sale 67 in February 1982.

Figure 2.1 provides an overview in the forces affecting U.S. natural gas market conditions during five epochs from the mid-1970s to 1996. MOEPSI's regulatory struggle with the State

[40]Paul Holtberg, Thomas J. Woods, Marie L. Lihn and Kathy D. Nice, "Baseline Projection Data Book," GRI, 1996, p. 517.

[41]Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), 53, 128, 624.

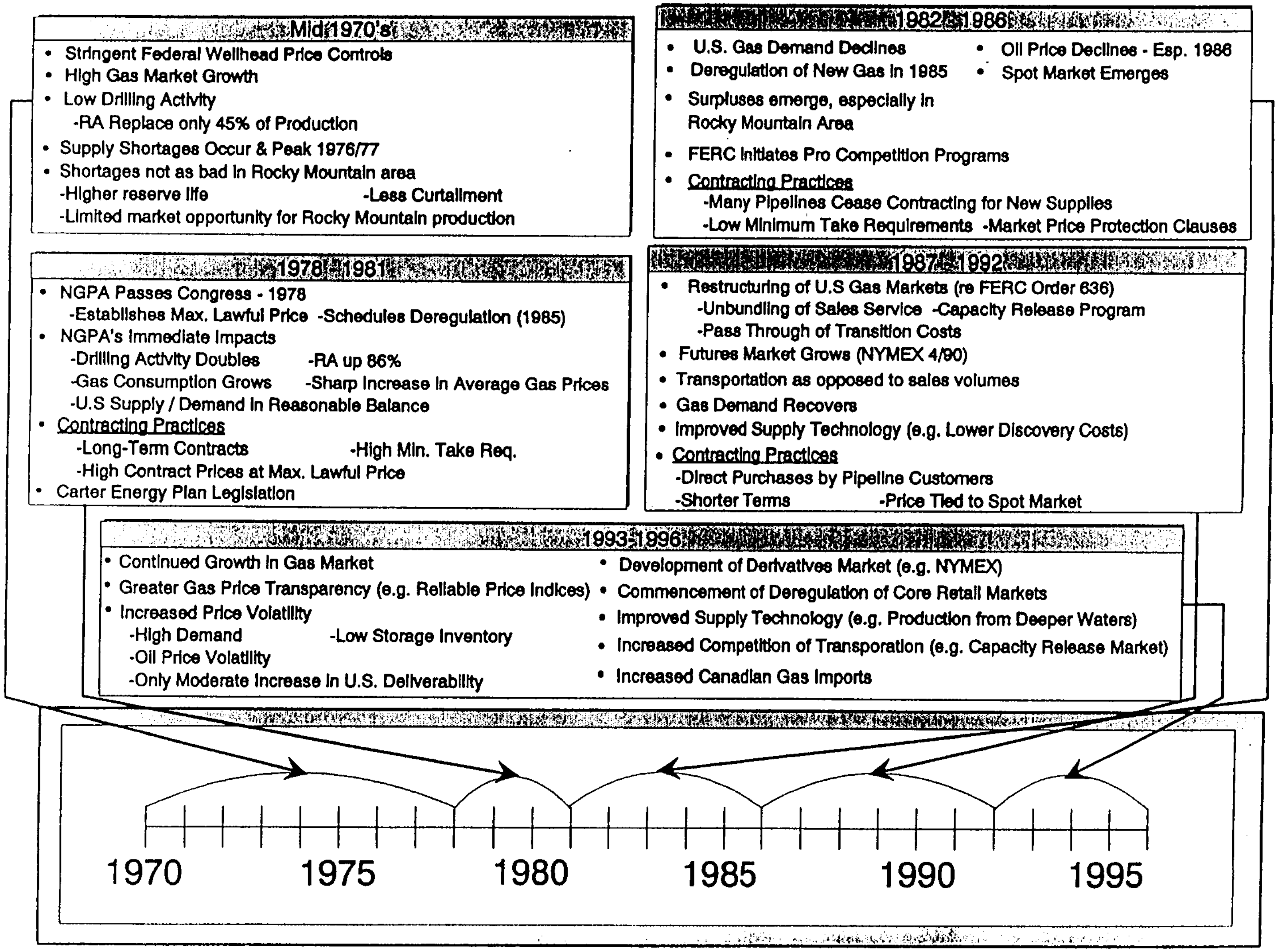

Figure 2.1. Epochs of U.S. Natural Gas Market Conditions.

Source: Foster Associates, 1997.

of Alabama fortunately occurred during the 1970s, the period of wellhead price controls. When MOEPSI filed for a permit in 1970, gas was selling for about $0.25 per MCF. The world crude oil price was about $3.00 per barrel. International crude oil price shocks related to the 1973 oil embargo and Middle East political instability in 1979 increased the price of world crude oil more than ten-fold, as can be seen on Figure 2.2., while domestic crude oil and gas prices remained controlled at lower levels throughout the 1970s.

High gas demand growth matched by low reserve replacement caused interstate gas shortages beginning in the early 1970s that worsened during the severe 1976/77 winter. Something had to be done. President Carter's Project Energy Independence was born.

2.2.1 NGPA: 1978 - 1982

The NGPA was passed by Congress in late 1978 in response to gas shortages that resulted from stringent federal price regulatory policy by the Federal Power Commission (succeeded by the Federal Energy Regulatory Commission in late 1977). The NGPA represented a series of compromises to mollify both consumer and producer interests. Among the provisions protecting consumers, the existing field price ceilings generally were retained (e.g., vintage pricing) for gas dedicated to interstate commerce at the enactment of the NGPA. New and higher price ceilings were created for gas discovered after 1978. In total, about 25 different pricing categories were created. Producers' interests were satisfied by immediately removing the price ceilings for certain new gas categories, beginning with "deep gas" (gas produced below 15,000 feet), and finally, by scheduling removal of price regulations for most post-NGPA gas in 1985.

The federal regulatory policy also included the determination of pipelines' resale rates based on the weighted average price of gas purchased by regulated companies (e.g., interstate pipelines). Because of this pricing mechanism that averaged all gas costs, new deregulated gas prices could increase substantially and yet the resale rate would remain competitive with fuel oil, at least for a while. Eventually, as producers concentrated their drilling efforts on the higher price categories and production from lower price vintage gas sources declined, average gas prices increased and gas became less competitive with alternatives. To illustrate, the U.S. wellhead average price increased from about $0.91 per MCF in 1978 to about $2.50 per MCF in the early 1980s.

Immediately after the NGPA was passed through about 1981, the price of unregulated new gas shot up. During this period, prices for NGPA Section 107 deep gas, which included Norphlet production, ranged between $7 and $9 per MCF. MOEPSI's discovered Norphlet gas reserves were now a treasure beyond anyone's expectation years earlier when they applied for the exploration permit.

A typical pipeline/producer contract executed during this period reflected these high prices, a "favored nation" provision, a minimum take provision, a take-or-pay provision and no mechanism for reducing the contract price even if subsequent market conditions warranted.

Forecasts of U.S. gas prices by authoritative sources (e.g., the U.S. Dept. of Energy) during this period show the expectation of continuously high and rising prices. One reason for the

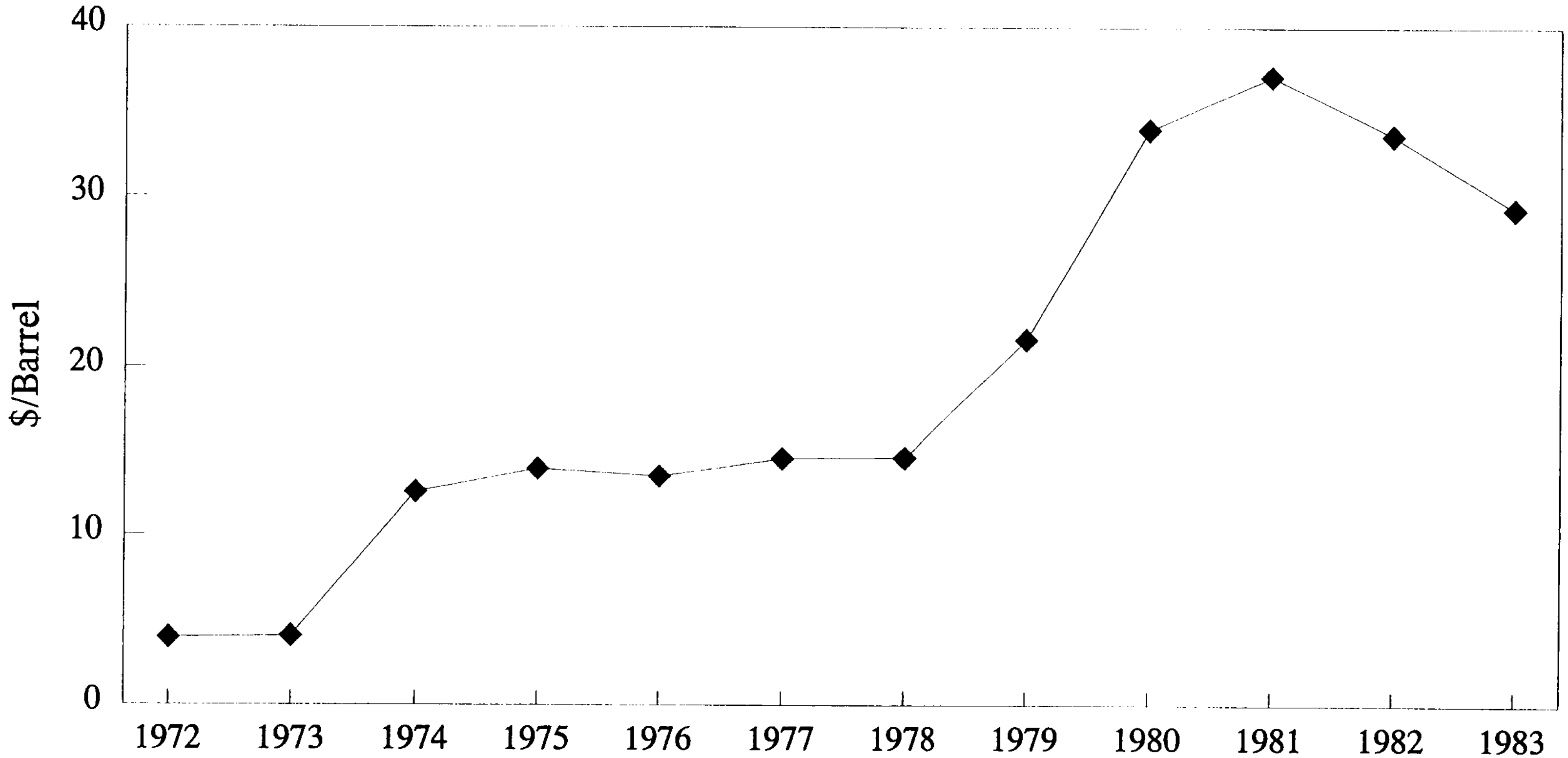

Figure 2.2. World Oil Prices, 1972-1983.

Source: USDOE, EIA, Annual Energy Reveiw, 1983; Annual Energy Outlook, 1983.

forecast of high gas prices was the fact that experts were forecasting high oil prices. Table 2.3 summarizes DOE's oil and gas price forecasts made in 1981, 1983 and 1985, compared with the actual prices that ensued. Prices shown for natural gas are the average of all categories of regulated and unregulated gas.

Table 2.3
DOE Oil and Gas Price Forecasts

		Projected (mid range)			
	Actual 1980	**1985**	**1990**	**1995**	**2000**
Forecasted in 1981 (1980 dollars)					
Oil ($/Barrel)	$34	$33	$49	$67	$75
Gas ($/MCF)	$1.59	$3.33	$6.02	$7.63	$8.28
Forecasted in 1983 (1983 dollars)					
Oil ($/Barrel)	$34	$27	$37	$50	NA
Gas ($/MCF)	$1.59	$2.68	$3.62	$6.33	NA
Forecasted in 1985 (1985 dollars)					
Oil ($/Barrel)	$34	$27	$34	$50	NA
Gas ($/MCF)	$1.59	$2.60	$2.68	$4.03	NA
Actual (nominal dollars)					
Oil ($/Barrel)	$34	$27	$22	$22	$15[1]
Gas ($/MCF)	$1.59	$2.51	$1.71	$1.75	$2.24[1]

Sources: USDOE(EIA) Annual Energy Outlook, 1981, 1982, and 1983.
USDOE(EIA), Monthly Energy Review, (11/96)
[1]USDOE(EIA), Short-Term Energy Outlook, (4/98), 1998 data.

EIA's 1980 Annual Report to Congress[42] reported that "the world is—and has been for some time—running out of relatively cheap sources of energy." The 1981 DOE forecast called for oil prices of $67 by 1995—in 1980 dollars. The 1981 DOE Annual Report to Congress projected oil prices in nominal dollars to reach $246 per barrel by 2000 on the first page of the report. Keep in mind that the Iranian revolution and Iran-Iraq conflicts reduced OPEC exports in 1979, while demand for OPEC oil had grown over the prosperous 1970s. Couple this with the March, 1979, Three Mile Island incident, which eliminated America's nuclear panacea—virtually overnight—and the Energy Crisis was born. Oil prices shot up to more than $40 per barrel in late 1979 from ~$11.00 in 1978. This is why price forecasts for more than $100 per barrel were common. Those were turbulent times.

In 1983 and 1985 DOE was still forecasting $50 oil and $4 - $6 average wellhead gas prices, even though it had dropped its novel "fly-up" assumption; i. e., that regulated gas prices would fly up to the $7 - $9 prices seen for deregulated prices in 1981 when all gas prices were

[42]USDOE, EIA, Annual Report to Congress, May 27, 1981, Executive Summary.

decontrolled in 1985. Remarkably, the 1983 Annual Energy Outlook discovered supply elasticity and noted that the significant supply response since 1981 caused it to reduce its 1990 gas price forecast.

These DOE forecasts of high gas prices were not unique, as illustrated by a comparison of oil and gas price forecasts prepared by others during the 1980-82 period. Table 2.4 shows the 1981 world oil price as $37 per barrel and forecasts to 1990 ranging between $41 and $64 in real dollars. U.S. average wellhead gas prices were forecast to range upward to $6.50 per MMBtu. Exxon called for a "50 percent increase in the purchase prices of Middle East crude oil in real terms between 1980 and 2000" in its 1980 World Energy Outlook.[43] Exxon was pessimistic about the outlook for U.S. gas supplies, projecting the decline in lower 48 production between 1973 and 1980 into the future and calling for completion of a pipeline from Alaska to the lower 48 to bring-in Alaska's huge gas reserves. Exxon projected that syngas would provide nearly 10 percent of U.S. gas supply by 2000. New gas discoveries were anticipated to account for 44 percent of the 2000 gas supply mix[44]—no doubt induced by the $5 - $6 gas price forecast.

2.2.2 Price Stabilization: 1982 - 1986

Forecasters began to reduce their price outlooks in the mid-1980s. Beginning in about 1982, energy market conditions changed dramatically. Oil prices declined for the first time since the sharp run-ups that began in 1973. An economic recession occurred in 1982 and excesses of natural gas supplies began to emerge. The "gas bubble" set in. So much new gas had been discovered within a few years that supplies overhung demand. By 1986, as MOEPSI was to discover, finding markets for new gas became difficult.

Gas prices began to decline. Gas contracting practices changed. In particular, purchasers began to negotiate market-sensitive pricing provisions into their contracts (e.g., market-out provisions). Because of the high-cost gas contracts that remained in effect, new gas prices had to be kept low in order for the average prices to be competitive. A typical market price during 1982-1984 for the new deep gas was in the range of $2.50 per MCF, compared with the $7 to $9 per MCF price of high cost gas under contracts with 1979-81 execution dates.

FERC initiated a pro-competitive policy. In October 1985, FERC issued a keystone rule, Order No. 436, that required interstate pipelines to become open-access carriers. As a result of these events, forecasters revised their subsequent price outlooks sharply downward. Table 2.3 shows that DOE's gas price forecast for 1990 dropped from $6.02 per MCF (1981 dollars) forecast in 1981, to $3.62 per MCF (1983 dollars) forecast in 1983, to $2.68 per MCF (1985 dollars), forecast in 1985.

[43]Exxon, World Energy Outlook, December, 1980, p. 3.

[44]Exxon Company U.S.A.'s Energy Outlook: 1980 - 2000, p. 12.

Table 2.4
Comparison of Forecasts of 1990 Oil and Gas Prices
1980-1982
$ (1981)

Product and Forecaster		**Actual 1981**	**Projected 1990**
World Crude Oil (per barrel)			
DOE —	EIA (2/82)	37	54
	NEPP (7/81)	37	52
	OPPA (8/82)	37	42
DRI		37	41
A.G.A		37	46
Exxon		37	46
Sherman Clark Associates		37	64
U.S. GAS (wellhead per MMBtu)			
DOE —	EIA (2/82)	1.98	6.54
	NEPP (7/81)	1.98	6.61
	OPPA (8/82)	1.98	5.67

Sources:
American Gas Association, TERA Analysis, November 21, 1980.
U.S. Department of Energy, Office of Policy, Planning and Analysis, Energy Projections to the Year 2000, A Supplement to the National Energy Policy Plan, July 1981.
U.S. Department of Energy, Office of Policy, Planning and Analysis, Energy Projections to the Year 2000, A Supplement to the National Energy Policy Plan, August 1982.
U.S. Department of Energy, Energy Information Administration, 1981 Annual Report to Congress, February 1982.
Data Resources, Inc. Energy Review, Summer 1982.
Exxon Corporation, World Energy Outlook, December 1980.
Sherman Clark Associates, Evaluation of World Energy Developments and Their Economic Significance, March 1981.

2.2.3 Restructuring and Emergent Commodity Pricing: 1986 - 1992

The petroleum industry experienced a "reverse price shock" in 1986, when price-induced reductions in demand for OPEC oil supplies resulted in excess OPEC producibility that the cartel was unable to manage. Saudi Arabia, in particular, concluded that it was no longer in its self-interest to continue to withhold production from markets. Saudi Arabia moved to netback pricing, thereby guaranteeing the competitiveness of its oil in world markets. As a consequence, it increased its production at substantially lower prices than had prevailed in late 1985/early 1986.

Oil prices plunged to less than $10 per barrel, before stabilizing generally in the $15 - $20 per barrel range since 1987 as shown on Figure 2.3. The resultant competitiveness of fuel oil in fuel-switchable markets further dampened natural gas demand growth, and the supply overhang continued to suppress natural gas wellhead prices. Average gas prices shown on Figure 2.4 stabilized under $2.00 per MCF. MOEPSI's discovered Norphlet gas had gone from less than a dollar per MCF to $9.00 per MCF and back to about $2.00 while permitting, exploration and development ensued. Quite a wild ride.

Confronted with the "gas bubble," natural gas producers in particular sought to increase the market for natural gas. The advent of non-discriminatory open-access transportation service on FERC-regulated natural gas pipelines under Order 436 held out the promise for market penetration and sales growth for producers, or marketers representing them. However, the dual-role of interstate pipelines as both transporter of gas owned by others, and merchant of gas sold to pipeline customers was an obvious conflict. Producers raised concerns at FERC that the institutional setting was impeding the market growth for a clean-burning essentially 100% domestic energy source. For example, the pipelines still had gas purchase contracts that made it logical for them to promote their bundled gas-plus-transportation service at the expense of limited progress on opening up markets for gas producers.

This tension led to FERC issuing Order 636 in April 1992. Order 636 effectively eliminated the interstate pipelines' gas sales role, streamlined the mechanisms for gas shippers to obtain pipeline transportation rights, and substantially advanced the FERC's objective of attaining robust competition in natural gas supply and acquisition. The resultant competitive gas supply markets have been further enhanced by the growth of short-term market price discovery, both in the cash and futures markets, through electronic communication systems. Pipeline usage planning centers around monthly forecasts, and therefore much gas is sold and priced just prior to the calendar month. Monthly natural gas pricing information is widely-disseminated by reliable trade publications, and longer-term contracts commonly have their prices set monthly based on such prices. Figure 2.5 shows the monthly average contract price series governing offshore Louisiana production. Month price volatility is apparent as seasonal demands, gas storage adequacy and colder winters significantly affect prices. Eastern U. S. had two successive cold winters—1995/96 and 96/97. Market conditions drove monthly contract prices above $3.00 per MCF for the first time since regulatory interference had pushed them that high 15 years earlier.

2.2.4 Commodity Pricing and Growth of Efficient Markets: Post 1993

Active and price-responsive markets for most of the natural gas sold in the U.S. have resulted from FERC initiatives and institutional changes. These institutional changes—away from regulatory rigidities and inefficient markets—combined with relatively low and fairly stable crude oil prices, and with technological advances in natural gas supply discovery and development, have kept natural gas wellhead prices at fairly stable and low levels. At the same time, dependence upon monthly pricing regime and the emergence of active day-by-day short term

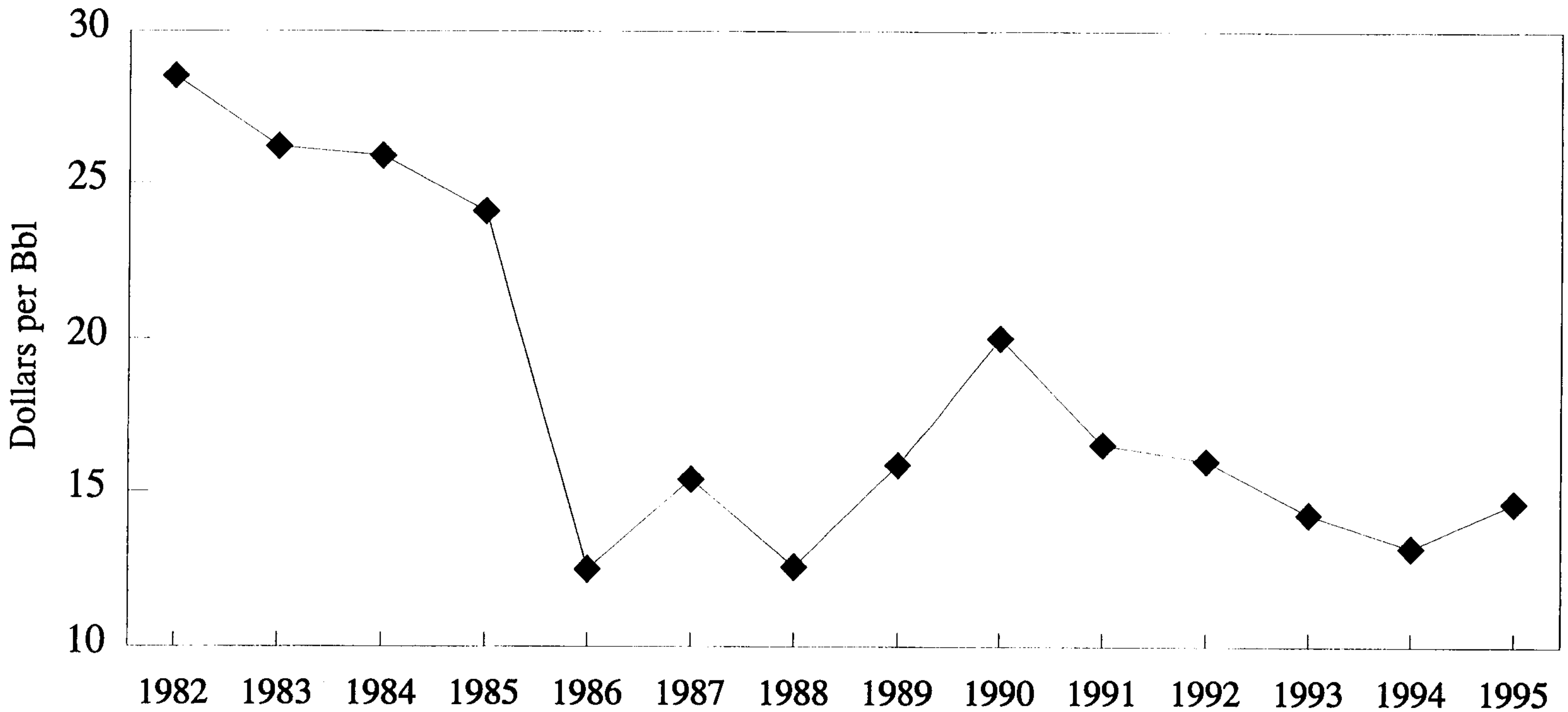

Figure 2.3. Average Crude Oil Prices, 1982-1995.

Source: USDOE, EIA, Annual Energy Review, various years.

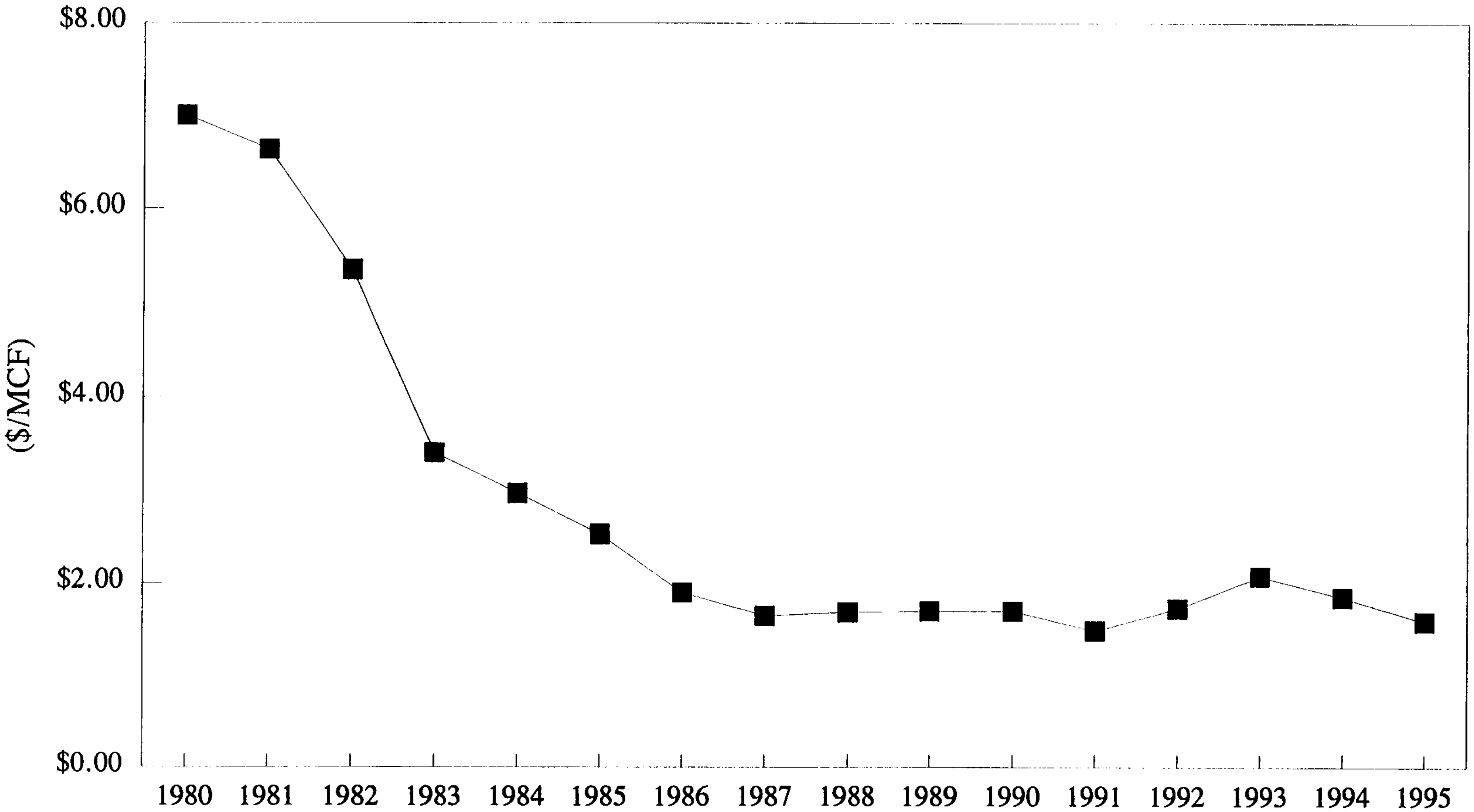

Figure 2.4. Estimated Initial Year Contract Price for Deep Well Gas.

Source: Foster Associates, Inc. 1996 estimates based on interstate gas pipeline PGA filings w/ FERC, trade press articles and EIA's Monthly Energy Review.

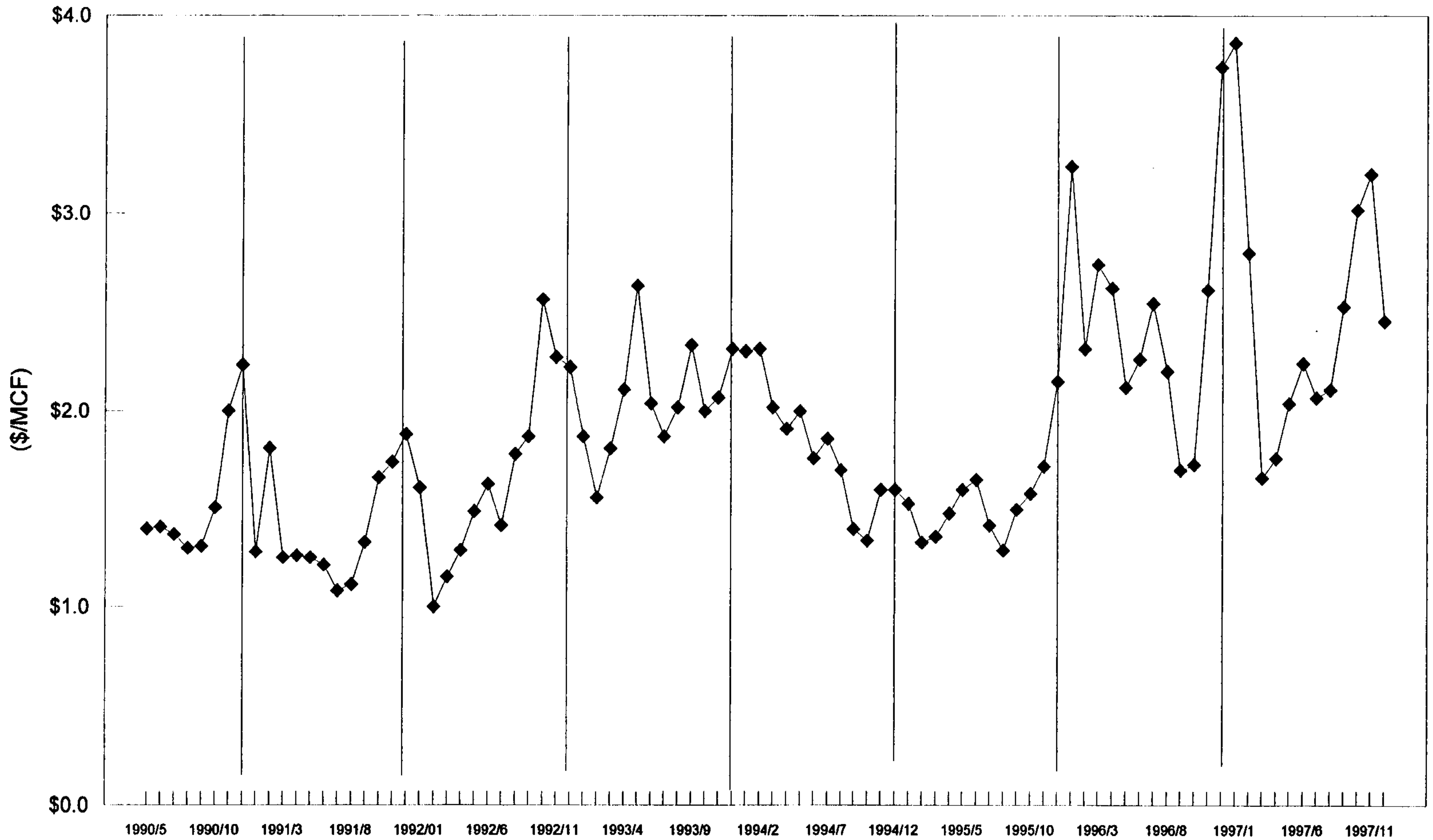

Figure 2.5. So. (Off) LA Spot Prices.

Source: USDOE, Federal Energy Regulatory Commission, 1997.

markets, have resulted in some price volatility. While some of this can be managed through contract pricing provisions that dampen day-to-day price changes, and by hedging with futures and derivatives contracts, much natural gas is sold under potentially volatile market-responsive pricing typical of commodity markets.

As U.S. gas markets have become more efficient, transportation profits have become more subject to market forces than to assured recovery of costs including a return on investment. Responses to such profit pressures include consolidation within the pipeline sector via mergers and acquisitions. Additionally, gas marketing combinations have occurred (e.g. Mobil and Pan Energy, Chevron and NGC Corp) to achieve scale and scope economies in a low margin business. Some firms have focused on "mid-stream" operations (gathering, processing and liquid extraction and marketing to apply market savvy to niche operations. Finally, exploration and development technological advances have enabled producers to bring economic energy supplies to market in a low price environment, while still making a profit. Norphlet exploration and development projects are not as profitable as lease purchasers might have anticipated, but Norphlet supplies continue to increase.

3.0 Mobile Bay Leasing History

During the period of peak outlooks for energy prices—between 1981 and 1984—Alabama leased tracts in state waters for bids totalling $800 million. MMS leased tracts in federal Mobile Bay OCS waters between 1982 and 1985 for bids totalling $562 million—$1.36 billion total. Seventeen Norphlet wells were spudded between 1981 and 1984, 13 of which became discovered gas wells—an amazing accomplishment. While changes in gas prices after 1982 and after 1986 no longer justify the extremely large bids seen in the 1981 and 1982 lease sales, nonetheless three new state Norphlet discoveries and one federal Norphlet discovery became development projects based on discoveries before year end 1984.

3.1 State Sale #1 - 1981

One important result of MOEPSI's discovery well 76-1 was the bidding interest in the state's March 1981 lease sale. Although Mobil had drilled only the single discovery well, with over 15 months to assess the implications of the discovery, industry bidders exposed $1.16 billion and the State of Alabama accepted bids on 13 tracts totalling $449.3 million plus royalty payments between 25 and 28 percent. Exxon submitted high bids of $255.9 million for seven of the 13 tracts awarded. Figure 3.1 shows the 13 tracts leased in the 1981 sale plus MOEPSI's four tracts.

Table 3.1 shows that bids were submitted on 35 tracts, but Commissioner John M. McMillan, Jr., Department of Conservation and Natural Resources and Edward Reynolds, Director of State Lands, rejected bids for 22 tracts. Asked why they accepted only a third of the bids, Mr. McMillan stated that "with nearly $450 million in the bank—more than we ever imagined—we simply rejected all the bids below about $2,000 an acre."[45] Figure 3.2 shows that the gain to Alabama from the 22 rejected tracts would have added $55 million to state coffers, about 12 percent more, bringing the total to $505 million. The largest bid rejected was Exxon's $8.6 million for tract 114; the largest bid per acre rejected was Getty's $2,222 for tract 110. (The tract was small and only would have added $2.9 million to Alabama's bonus receipts.) The sale tripled Louisiana's previous high cash bonus payday of $157.7 million.[46]

"We've struck oil," a jubilant Governor Fob James quipped after the cash bonuses were counted. Commissioner McMillan was shocked by the amounts bid. Industry observers stated before the bids were opened that maybe $250 million at risk might have been expected.[47] The $1.16 billion amount was nearly five times higher. Current Lands Division manager James Griggs described the industry's bids as "gold fever."[48] Exxon clearly bet serious money on their 1980 World Energy Outlook projections.

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[45]Personal communication, Montgomery, Alabama, February 11, 1997.

[46]OGJ, "Mobil strike helps spark Alabama tract bidding," April 13, 1981, p. 36-37.

[47]"Oil bonanza couldn't have come at better time for state," Cullman Times, April 21, 1981.

[48]Personal communication, Montgomery, Alabama, February 11, 1997.

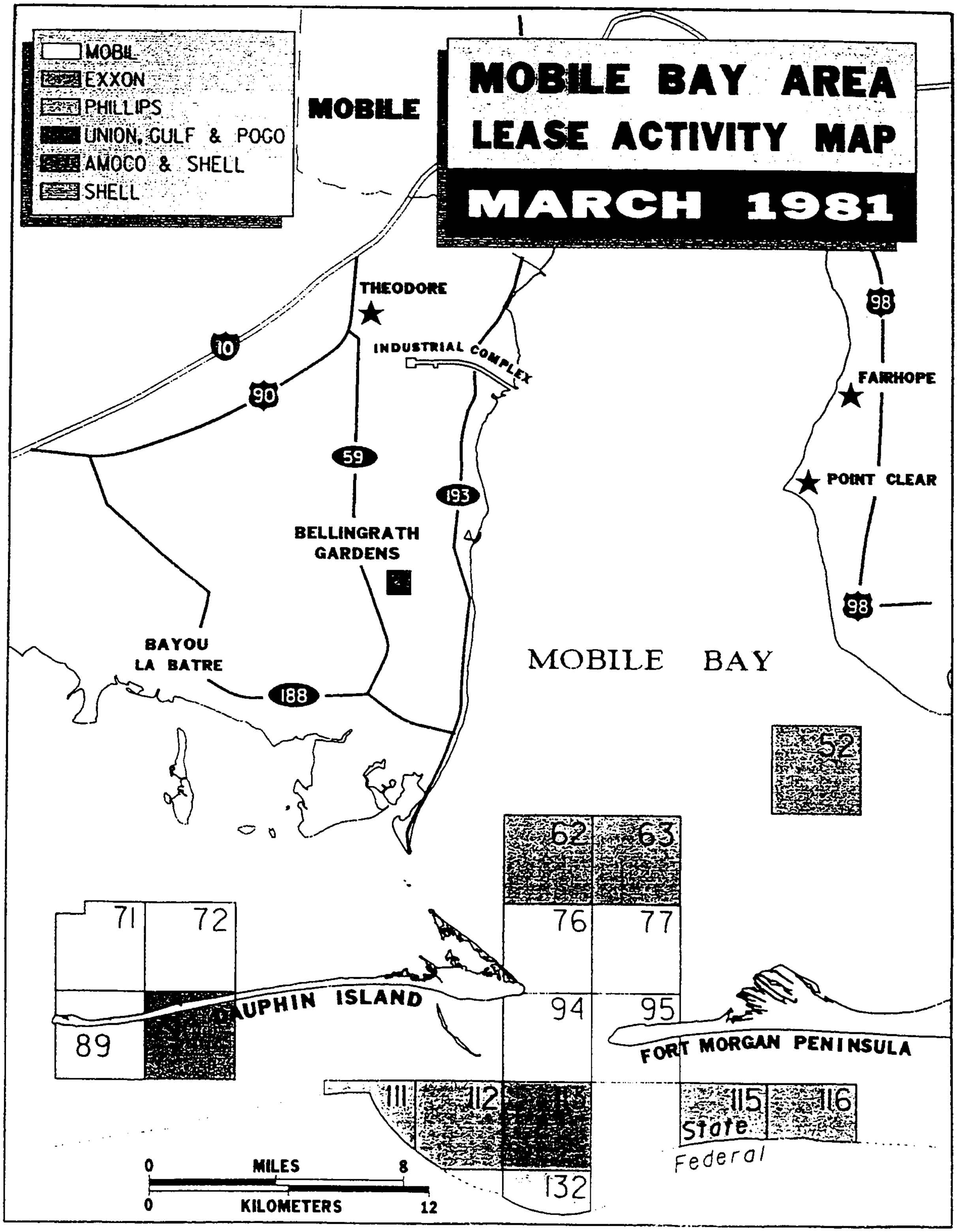

Figure 3.1. Mobile Bay Area Lease Activity Map, March 1981.

Source: MOEPSI, 1997.

Table 3.1
Bids Received for the March 1981 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty %	Result[1]
49	5,164	Conoco, et al.	1,780,000	344.69	28.7	R
50	5,164	Conoco, et al.	780,000	151.05	28.7	R
52	5,164	Exxon	9,112,000	1,764.52	25	A
		Shell	533,000	103.22	25	R
59	4,720	Getty, Conoco, et al.	722,160	153.00	25	R
60	4,711	Getty, Conoco, et al.	720,783	153.00	25	R
62	5,164	Exxon	10,522,000	2,037.57	27	A
		Getty, Conoco, et al.	3,940,132	763.00	28.7	R
		Sunlite International, Inc.	581,040	112.52	26.1	R
63	5,164	Exxon	15,226,000	2,948.49	27	A
		First Energy Corp.	4,389,400	850.00	25	R
		Getty, Conoco, et al.	2,752,412	533.00	28.7	R
		Shell	533,000	103.21	25	R
64	5,164	Sunlite International, Inc.	581,040	112.52	26.1	R
71	4,196	MOEPSI	40,425,000	9,634.17	25	A
		SOHIO and Hunt	37,510,000	8,939.47	25	R
		SOHIO and Hunt	32,200,000	7,673.97	30.4	R
		SOHIO and Hunt	17,300,000	4,122.97	51	R
		Getty, Conoco, et al.	15,537,788	3,703.00	28.7	R
		Shell and Amoco	9,270,000	2,209.25	25	R
		Union, Gulf, Pennzoil & Total Pet.	7,381,000	1,759.06	25	R
		Chevron	2,142,000	510.49	26.2	R
		Louisiana Land & Exploration	839,200	200.00	37.5	R
72	5,164	MOEPSI	31,535,000	6,106.70	25	A
		SOHIO and Hunt	23,700,000	4,589.46	25	R
		SOHIO and Hunt	21,200,000	4,105.34	30.4	R
		Getty, Conoco, et al.	17,573,092	3,403.00	26.7	R
		Union, Gulf, Pennzoil & Total Pet.	14,676,000	2,841.98	25	R
		Shell and Amoco	9,130,000	1,768.01	25	R
		SOHIO and Hunt	7,300,000	1,413.63	51	R
		Exxon	5,104,000	988.38	25	R
		Chevron	2,142,000	414.79	26.2	R
		Louisiana Land & Exploration	1,032,800	200.00	37.5	R
73	3,690	Shell	5,674,000	1,537.67	25	R
		Union, Natomas & Pennzoil	5,130,000	1,390.24	30	R
		Exxon	5,106,000	1,383.74	25	R
		Louisiana Land & Exploration	959,400	260.00	37.5	R
88	5,112	Getty, Conoco, et al.	7,427,736	1,453.00	26.7	R
		Hunt and SOHIO	1,538,712	301.00	34	R
		Chevron	555,000	108.57	26.2	R

Table 3.1 (continued)
Bids Received for the March 1981 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty %	Result†
89	4,811	Phillips, Hunt and SOHIO	42,712,059	8,878.00	25	A
		Phillips, Hunt and SOHIO	35,666,022	7,413.43	30.4	R
		Phillips, Hunt and SOHIO	20,277,024	4,214.72	51	R
		Union, Gulf, Pogo, Natomas, Pennzoil and Total Pet.	9,632,000	2,002.08	25	R
		Getty, Conoco, et al.	6,749,833	1,403.00	26.7	R
		MOEPSI	5,145,000	1,069.42	25	R
		Shell and Amoco	1,180,000	245.27	25	R
90	4,612	Union, Gulf, Pogo, Natomas, Pennzoil and Total Pet.	21,879,000	4,743.93	25	A
		SOHIO and Hunt	13,353,000	2,895.27	25	R
		SOHIO and Hunt	11,317,848	2,454.00	30.4	R
		Getty, Conoco, et al.	9,652,916	2,093.00	26.7	R
		MOEPSI	5,235,000	1,135.08	25	R
		SOHIO and Hunt	3,613,734	783.55	51	R
		Shell and Amoco	570,000	123.59	25	R
91	5,010	Pennzoil and Natomas	5,105,000	1,018.96	30	R
92	5,164	Natomas	3,000,000	580.94	35	R
		Hunt and SOHIO	2,210,192	428.00	34	R
		Conoco, et al.	1,337,000	258.91	28.7	R
		Shell	887,000	171.77	25	R
93	4,823	Conoco, et al.	3,713,000	769.85	28.7	R
		MOEPSI	1,010,000	209.41	25	R
96	3,834	First Energy Corp.	5,751,000	1,500.00	25	R
		Getty, Conoco, et al.	3,768,000	982.78	25	R
		Getty, Conoco, et al.	975,400	254.41	33.7	R
		Hunt and SOHIO	475,416	124.00	34	R
97	3,217	Hunt and SOHIO	2,100,701	653.00	34	R
98	3,697	Hunt and SOHIO	2,101,745	568.50	34	R
		Natomas	897,271	242.70	25	R
99	2,806	Natomas	684,355	243.89	25	R
		Hunt and SOHIO	352,153	125.50	34	R
100	3,479	Natomas	357,711	102.82	25	R
101	4,438	Natomas	456,315	102.82	25	R
103	5,062	Conoco, et al.	837,000	165.35	28.7	R
104	3,846	Conoco, et al.	647,000	168.23	28.7	R
110	1,295	Getty, Conoco, et al.	2,878,000	2,222.39	25	R
		Chevron	2,620,000	2,023.17	26.2	R
		Hunt and SOHIO	450,660	348.00	34	R

Table 3.1 (continued)
Bids Received for the March 1981 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty %	Result[1]
111	1,687	Exxon	53,168,000	31,516.30	28	A
		MOEPSI	22,225,000	13,174.27	25	R
		Shell and Amoco	21,340,000	12,649.67	25	R
		Getty, Conoco, et al.	12,078,000	7,159.45	28.7	R
		Pennzoil and Natomas	10,133,000	6,006.52	25	R
		Chevron	8,560,000	5,074.10	26.2	R
		Chevron	3,725,000	2,208.06	35	R
		Hunt and SOHIO	655,400	388.50	34	R
112	4,932	Exxon	137,254,000	27,829.28	28	A
		Getty, Conoco, et al.	37,067,000	7,515.61	26.7	R
		Getty, Conoco, et al.	25,137,000	5,096.71	33.7	R
		Shell and Amoco	10,580,000	2,145.17	25	R
		MOEPSI	5,815,000	1,179.03	25	R
		Pennzoil and Natomas	5,077,000	1,029.40	25	R
		Chevron	2,112,000	428.22	26.2	R
		Hunt and SOHIO	759,528	154.00	34	R
113	5,123	Shell and Amoco	34,370,000	6,708.96	25	A
		Exxon	26,154,000	5,105.21	27	R
		Getty, Conoco, et al.	12,157,000	2,373.02	25	R
		Getty, Conoco, et al.	9,243,000	1,804.22	33.7	R
		Union, Natomas & Pennzoil	9,177,000	1,791.33	25	R
		Hunt and SOHIO	1,308,927	255.50	34	R
114	4,782	Exxon	8,608,000	1,800.08	25	R
		Getty, Conoco, et al.	7,273,000	1,520.91	28.7	R
		Union, Pennzoil & Total Pet.	4,171,000	872.23	25	R
		Hunt and SOHIO	755,556	158.00	34	R
115	3,416	Exxon	12,308,000	3,603.04	27	A
		Conoco, et al.	7,129,000	2,086.94	28.7	R
		Union	1,817,000	531.91	25	R
		First Energy Corp.	1,708,000	500.00	25	R
		Hunt and SOHIO	1,310,036	383.50	34	R
116	3,254	Exxon	18,323,000	5,602.95	27	A
		Conoco, et al.	12,840,000	3,945.91	28.7	R
		Hunt and SOHIO	1,630,254	501.00	34	R
117	3,479	Hunt and SOHIO	1,612,518	463.50	34	R
		Exxon	1,104,000	317.33	25	R
118	3,429	Exxon	1,102,000	321.38	25	R
		Hunt and SOHIO	353,188	103.00	34	R
132	2,367	Shell	22,435,000	9,478.24	25	A
Total Industry Exposure			1,156,735,457			
Total Accepted			449,269,059			

[1] R - rejected; A - accepted

Source: Alabama Dept. of Conservation and Natural Resources, 1997;
Alabama Oil and Gas Board, 1986.

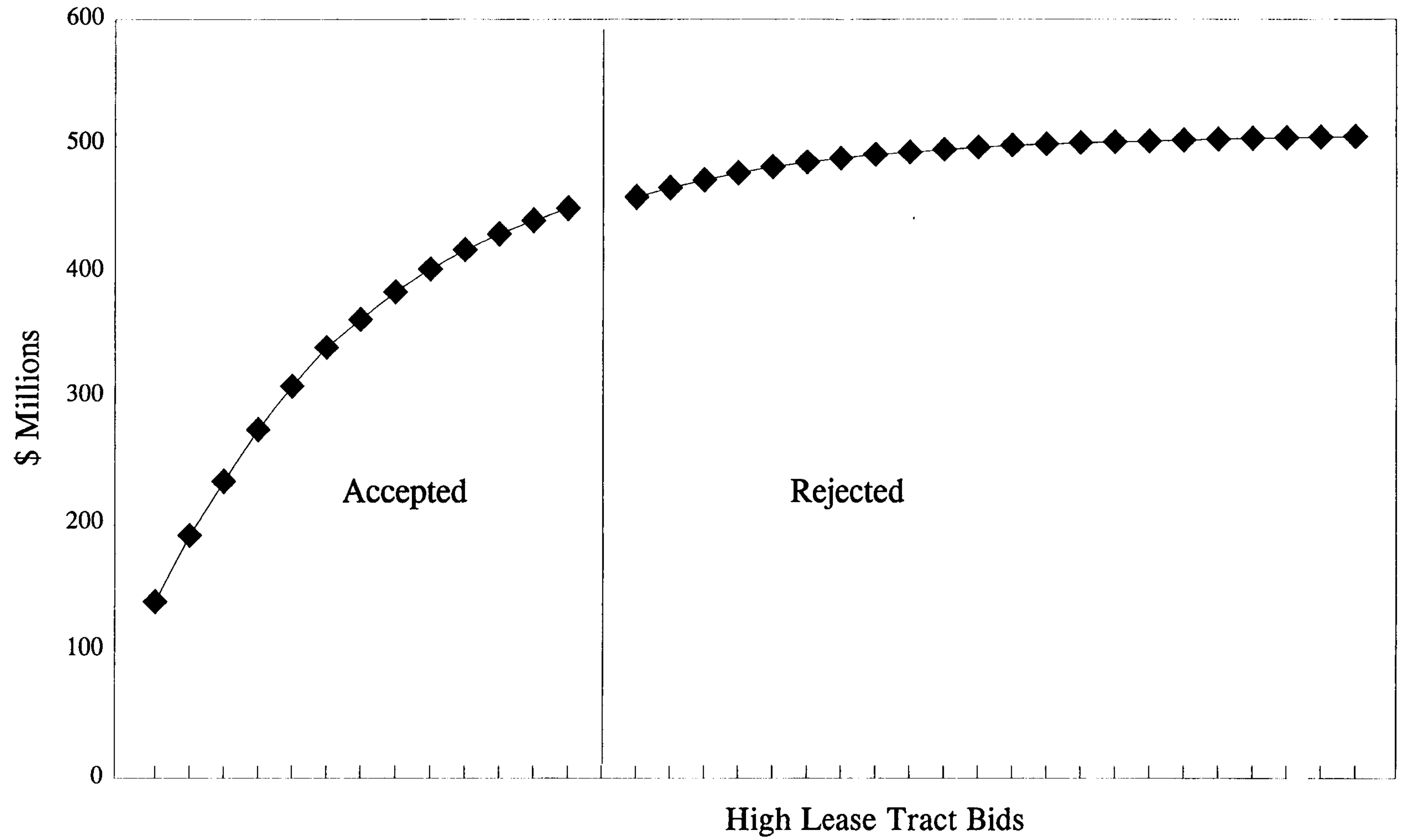

Figure 3.2. State of Alabama Cumulative Lease Bids, 1981.

Source: Table 3.1.

The bonanza couldn't have come at a better time because interest rates were at record highs. The money was invested in 90-day time deposits earning 13.9 to 14.4 percent while the governor and state legislators decided what to do with the bonanza.

Exxon, which exposed $303 million in 13 bids, paid the highest two bonuses to lease tracts 111 and 112 for $53.2 million and $137.3 million, leaving a total of $131.2 million "on the table" for tracts 111 and 112. Exxon described their exuberance as simply "reflecting their interest in the area" and wouldn't discuss their high bids with the Oil and Gas Journal's reporter.[49] MOEPSI, holding the discovery well just northeast of these two tracts, offered only $28 million for them, bidding only $5.8 million for tract 112 compared to Exxon's $137.3 million. Exxon substantially overbid to win tracts 62 and 63 as well, leaving $17.4 million "on the table" for those tracts. MOEPSI, which held the leases for tracts 76 and 77 immediately south of tracts 62 and 63, didn't even bid on them. MOEPSI's interest lay to the west; they bid their highest amounts, $71.9 million, to win tracts 71 and 72. Tract 72 attracted the highest number of bidders—eight—in the sale.

Exxon acquired leases for tracts 115 and 116 for $30.5 million. These winning bids were in line with the losers' bids. Shell was the other big winner in the sale, acquiring leases on tracts 113 and 132 for $57.1 million—overbidding Exxon by 35 percent on tract 113, and submitting the only bid on 132.

To jump ahead of the story: Exxon and Shell successfully bought their way into the Norphlet game. Exxon's tracts subsequently became three Norphlet fields—Bon Secour Bay, North Central Gulf and Northwest Gulf. Shell's acreage, between Exxon's Gulf of Mexico fields, became the Fairway field.

3.2 OCS Lease Sale 67 - 1982

The following February 1982 MMS leased its first acreage contiguous to state waters of Coastal Alabama as part of OCS Sale 67, which also included tracts off Texas and Louisiana in deep water. MOEPSI, bidding with Conoco and Getty (now Texaco), was the biggest winner in Coastal Alabama OCS, leasing tracts 778, 779, 822, 823, and 824 for $100.2 million to beat Exxon which bid $76.5 million for the tracts. The tracts adjoin Exxon's previous high bid state tracts 111 and 112. Exxon, having overbid $131 million for tracts 111 and 112 in the 1981 state sale, now was $24 million short of controlling the highest priced leases acquired in the OCS sale—and all the acreage in the neighborhood of their high bid state tracts 111 and 112.

A group comprised of Chevron, Gulf, Pennzoil, and Union acquired tracts 861 and 862 for $41.2 million. Groups led by Shell and ARCO were the other major winning bidders picking up tracts 908 and 909 for $52.5 million. MMS accepted a total of $218.7 winning bids for 17 Alabama OCS tracts, shown on Table 3.2. The 1981 state sale and 1982 federal sale introduced all the subsequent Norphlet operators to Coastal Alabama—MOEPSI, Exxon, Shell, Chevron, BP and Unocal.

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[49]OGJ, "Mobil strike helps spark Alabama tract bidding," April 13, 1981, p. 36-37.

Table 3.2
Leased Blocks in the Federal OCS Water Near Alabama's State Coastal Waters through 1985

Offshore Block no.1	Acres	Original Lessee	OCS Lease Sale no.	Total Bonus $	Bonus per acre $
M 779, 823, 824	5,585	MOEPSI, Conoco and Getty	67	55,119,000	9,856
M 778, 822	5,324	MOEPSI, Conoco and Getty	67	45,117,000	8,471
M 909	5,760	Shell, Florida Exploration, Fluor Oil & Gas and Crown Central	67	28,277,000	4,909
M 908	5,760	ARCO, Texas Gulf, Murphy, and ODECO	67	24,197,760	4,201
M 861	5,198	Gulf, Union, Pennzoil and Chevron	67	23,616,000	4,543
M 862	5,618	Chevron, Gulf, Pennzoil and Union	67	17,616,000	3,135
M 867	5,760	Exxon	67	6,747,000	1,171
M 870	5,618	Placid	67	5,084,643	905
M 864	5,760	Tenneco	67	4,880,000	847
M 821	4,028	SOHIO	67	3,000,000	745
M 906	5,760	Chevron	67	2,110,000	366
M 866	5,760	Exxon	67	1,211,000	210
M 868	5,687	Exxon	67	1,014,000	178
M 827	3,174	Exxon	67	718,000	226
	Subtotal 1982			***218,707,403***	
M 905	5,760	Union	69 (Part II)	881,900	153
	Subtotal			***881,900***	
M 863	5,760	Tenneco, ARCO, Murphy, ODECO and Elf Aquitaine	72	7,930,000	1,377
M 952	5,760	ODECO, Koch and Santa Fe Energy	72	5,667,000	984
M 959	5,760	ARCO and Elf Aquitaine	72	5,553,000	964
M 955	5,760	ODECO, Koch and Santa Fe Energy	72	4,778,000	830
M 953	5,760	ODECO, Koch and Santa Fe Energy	72	3,642,000	632
M 826	1,430	Placid	72	3,563,560	2,492
M 961	5,760	Chevron and Union	72	2,572,000	447
M 915	5,760	Chevron and Union	72	1,300,000	226
M 958	5,760	Chevron and Union	72	1,300,000	226
M 916	5,760	Chevron and Union	72	1,300,000	226
M 917	5,760	Chevron and Union	72	1,227,000	213
M 960	5,760	ARCO and Elf Aquitaine	72	1,053,000	183
M 904	5,760	Union	72	900,000	156
	Subtotal 1983			***40,785,560***	
P 881	5,760	Conoco	79	957,000	166
P 970	5,760	Conoco and Getty	79	1,214,000	211
P 969	5,760	Conoco and Getty	79	1,515,000	263
	Subtotal			***3,686,000***	
M 869	4,503	Getty, Conoco and Pennzoil	81	32,078,000	7,123
M 913	5,760	Exxon	81	18,887,000	3,279
M 828	3,090	Exxon	81	10,302,000	3,334
M 912	5,760	Exxon	81	9,090,000	1,578
M 962	5,760	Getty, Conoco and Pennzoil	81	6,818,000	1,184
M 872	5,760	Getty, Conoco and Pennzoil	81	3,518,000	611
M 1005	5,760	Getty, Conoco and Pennzoil	81	3,518,000	611
M 1006	5,760	Getty, Conoco and Pennzoil	81	3,037,000	527
M 873	5,760	Getty, Conoco and Pennzoil	81	2,518,000	437
M 829	2,775	Exxon	81	2,424,000	873
M 918	5,760	Getty	81	1,616,600	281
M 865	5,760	Union	81	1,567,000	272
M 830	2,909	Getty, Conoco and Pennzoil	81	1,518,000	522

Table 3.2 (continued)
Leased Blocks in the Federal OCS Water Near Alabama's State Coastal Waters through 1985

Offshore Block no.[1]	Acres	Original Lessee	OCS Lease Sale no.	Total Bonus $	Bonus per acre $
M 860	5,760	Union, Chevron, Gulf and Pennzoil	81	1,351,000	235
M 996	5,760	Conoco and Getty	81	1,108,000	192
M 1002	5,760	Union	81	989,000	172
M 1003	5,760	Union	81	989,000	172
M 1004	5,760	ARCO and elf Aquitaine	81	920,000	160
M 995	5,760	Conoco and Getty	81	918,000	159
M 911	5,760	Exxon	81	909,000	158
	Subtotal 1984			***104,075,600***	
P 971	5,760	ODECO, Murphy, Petrofina, Felmont and Minatome	94	1,020,000	177
P 925	5,760	ODECO, Murphy, Petrofina, Felmont and Minatome	94	1,020,000	177
P 837G	2,828	Union	94	454,000	161
	Subtotal			***2,494,000***	
M991	5,740	Conoco, Pennzoil and Amoco	98	51,096,000	8,188
M 999	5,760	SOHIO, Petrofina and Monsanto	98	27,137,000	4,711
M 992	5,760	Conoco, Pennzoil and Amoco	98	20,325,000	3,529
M 1000	5,760	SOHIO, Petrofina and Monsanto	98	12,625,000	2,192
M 956	5,760	Conoco and Amoco	98	11,767,800	2,043
M 950	5,760	Union	98	11,260,000	1,955
M 874	5,760	Union	98	9,750,000	1,693
M 871	5,760	Conoco, Union, Pennzoil and Amoco	98	7,657,000	1,329
M 948	5,760	Union	98	5,137,000	892
M 1001	5,760	SOHIO, Petrofina and Monsanto	98	5,127,000	890
M 914	5,760	Santa Fe and HNG	98	5,076,000	881
M 994	5,760	SOHIO, Petrofina and Monsanto	98	4,256,000	739
M 998	5,760	SOHIO, Petrofina and Monsanto	98	3,712,000	644
M 951	5,760	Union and Chevron	98	3,660,000	635
M 993	5,760	SOHIO, Petrofina and Monsanto	98	3,471,000	603
M 949	5,760	Union	98	2,875,000	499
M 910	5,760	Exxon	98	2,220,000	385
M 997	5,760	Exxon	98	1,614,000	280
M 957	5,760	Exxon	98	1,510,000	262
M 907	5,760	Tenneco, ARCO, Elf Aquitaine, Murphy and ODECO	98	1,459,000	253
	Subtotal 1985			***191,734,800***	
TOTAL OF ALL LEASES				***562,365,263***	

[1] M - Mobile Area, P - Pensacola Area (western area only).

All Federal blocks have a primary lease term of 5 years, an annual rental of $3.00 per acre, and a royalty payment of 16.67 percent.

Source: U.S. Department of the Interior, Minerals Management Service, 1998;
Alabama Oil and Gas Board, 1986.

3.3 State Lease Sale #2 - 1982 and OCS Sale 72 - 1983

The state had a second lease sale in September 1982. Table 3.3 shows that nine bids were received for six tracts; only $12.5 million was exposed and only one tract, 110, north of federal tract 822, was leased to MOEPSI's group for $3.1 million with a 25 percent royalty. Shell bid $1.7 million for tract 114, well under Exxon's rejected bid in 1981, and the state rejected the offer for the second time. MOEPSI's winning bid for tract 110 was the only bid over $2,000 per acre.

MMS had a second small sale in May 1983 at which the highest bid tract was $7.9 million for tract 863. Tenneco and a group comprised of ARCO, Murphy, ODECO and Elf leased this tract adjoining Tenneco's tract 864 that was leased the year before. Union and Chevron acquired tracts 904, 916 and 961 for bids near $1.0 million that subsequently became Norphlet discoveries. The highest bid per acre, $2,492, came for tract 826, adjoining Exxon's tracts 114 and 115, west of Exxon's 827. Total accepted bids amounted to $40.8 million as shown on Table 3.2.

A number of tracts were bought for their Miocene prospects. Bids in the range of $5.0 million were received for tracts 952, 955, and 959, which became producing Miocene properties.

3.4 State Lease Sale #3 and OCS Sale 81 - 1984

Two important lease sales in 1984 added to the Alabama acreage available for exploration: OCS Lease Sale 81, April 1984; and state Lease Sale #3, August 1984. Table 3.2 shows that Sale 81 leased 20 federal tracts in Coastal Alabama for $104.1 million. The highest bid, $32.1 million, was paid for tract 869, just south of Shell's state tract 132. Getty (now Texaco), Conoco and Pennzoil acquired this tract. Getty, bidding alone and with this group, acquired ten leases to become the most active participant. Exxon was the second most active, winning the second highest bid tract, 913, for $18.9 million, and adding to its acreage south of state tracts 115 and 116 by acquiring tracts 828 and 829 for $12.7 million. Exxon acquired a total of five tracts. MOEPSI acquired none.

State Lease Sale #3 exposed $493.2 million and awarded 19 state tracts for $347.5 million plus royalties of between 16.67 and 20 percent, as shown on Table 3.4. Exxon dominated the sale, with high bids of $289.8 million accepted by the state for 14 tracts. Exxon's highest two bids were $53 million for tract 114 and $46 million for tract 78. Exxon acquired all the state acreage surrounding their 1981 leases. The state, which had rejected an $8.4 million bid from Exxon in 1981 for tract 114, clearly benefitted by its strategy as tract 114 received the highest bid in the 1984 sale. In fact, the state bettered its financial position by $247.6 million on the bids for tracts it rejected in 1981 and 1982, as shown on Table 3.5. Exxon contributed $238.8 million of the increase in bids.

Mobil acquired no new acreage in the sale, bidding on only five tracts and bidding an average of 6.4 percent of Exxon's winning bids for tracts 78, 91, 92, 93, and 96 as shown on Table 3.6.

Table 3.3
Bids Received for the September 1982 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty %	Result[1]
91	4,991	Pennzoil	1,500,000	300.54	25	R
92	5,164	Shell	1,033,000	200.04	25	R
93	4,723	Exxon	1,408,000	298.12	25	R
		Shell	1,047,000	221.68	25	R
109	2,329	SOHIO	852,577	366.07	25	R
110	1,295	MOEPSI, Getty & Concoco	3,117,000	2,406.95	25	A
		Exxon	1,206,000	931.27	25	R
		Chevron	611,000	471.81	25	R
114	4,782	Shell	1,713,000	358.22	25	R
Total Industry Exposure			12,487,577			

[1] R - rejected; A - accepted

Source: Alabama Dept. of Conservation and Natural Resources, 1997;
Alabama Oil and Gas Board, 1986

Table 3.4
Bids Received for the August 1984 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty[1] %	Result[2]
13	4,650	Exxon	1,412,000	303.66	16.67	R
14	5,165	Exxon	2,723,000	527.20	16.67	A
40	5,040	Exxon	1,212,000	240.48	16.67	R
50	5,165	Exxon	1,518,000	293.90	16.67	R
51	5,165	Exxon	1,413,000	273.57	16.67	R
59	4,665	Exxon	4,244,000	909.75	20	A
		Conoco and Getty	1,212,000	259.80	20	R
64	5,165	Exxon	32,828,000	6,355.86	20	A
		Conoco and Getty	1,414,000	273.77	20	R
73	4,795	Exxon	12,624,000	2,632.74	20	A
		Pennzoil & Total Pet.	12,000,014	2,502.61	20	R
		ARCO	6,095,000	1,271.16	20	R
		Tenneco	2,496,000	520.54	20	R
		Conoco and Getty	1,111,000	231.70	20	R
78	4,980	Exxon	45,972,000	9,231.33	20	A
		Conoco and Getty	3,416,000	685.94	20	R
		Shell	1,674,000	336.14	20	R
		Amoco	1,215,120	244.00	20	R
		MOEPSI	1,027,500	206.33	20	R
79	4,438	Exxon	1,313,000	295.85	16.67	R
		Amoco	1,127,252	254.00	16.67	R
88	5,131	SOHIO	7,610,000	1,483.14	16.67	A
		Conoco and Getty	3,213,000	626.19	16.67	R
91	5,012	Exxon	16,540,000	3,300.08	20	A
		Union and Pennzoil	7,360,000	1,468.48	20	R
		MOEPSI, Conoco, Getty and AGIP	2,127,000	424.38	20	R
92	5,165	Exxon	39,672,000	424.38	20	A
		Union, Pennzoil & Pogo	15,350,000	7,680.93	20	R
		MOEPSI, Conoco, Getty and AGIP	5,203,300	2,971.93	20	R
93	4,831	Exxon	39,364,000	8,148.21	20	A
		Union, Pennzoil & Pogo	8,350,000	1,728.41	20	R
		MOEPSI, Conoco,	2,027,000	419.58	20	R
		Getty and AGIP			20	R
		SOHIO	1,259,000	260.61	20	R
		Shell	989,000	204.72	20	R
96	4,093	Exxon	43,738,000	10,686.05	20	A
		Union	5,889,000	1,438.80	20	R
		Conoco and Getty	2,317,000	566.08	20	R
		Shell	1,674,000	408.99	20	R
		MOEPSI	1,527,500	373.20	20	R

Table 3.4 (Continued)
Bids Received for the August 1984 State Lease Sale

State Block No.	Acreage	Bidder	Total Bonus $	Bonus Per Acre $	Royalty[1] %	Result[2]
97	3,395	Exxon	14,634,000	4,310.46	16.67	A
98	3,652	Exxon	6,664,000	1,824.75	16.67	A
99	2,770	Exxon	608,000	219.49	16.67	R
109	2,511	SOHIO	1,100,000	438.07	16.67	A
		Getty	555,200	221.11	16.67	R
114	4,807	Exxon and Louisiana Hunt	52,984,000	11,022.26	16.67	A
		Union, Pennzoil & Pogo	15,370,000	3,197.42	16.67	R
		Shell and Amoco	11,326,000	2,356.15	16.67	R
		Conoco and Getty	5,419,000	1,127.31	16.67	R
117	3,541	Exxon	14,428,000	4,074.56	16.67	A
		Union	3,367,000	950.86	16.67	R
		Amoco	1,157,907	327.00	16.67	R
		Conoco and Getty	1,121,000	316.58	16.67	R
118	3,669	Union and Pogo	9,310,000	2,537.48	16.67	A
		Exxon	7,572,000	2,063.78	16.67	R
		Amoco	1,185,087	323.00	16.67	R
		Conoco, Getty and Pennzoil	1,127,000	307.17	16.67	R
119	2,945	Exxon	1,820,000	618.00	16.67	A
131/133	1,535	Exxon and Louisiana Hunt	1,228,000	800.00	16.67	A
Total Accepted Bids			347,483,000			
Total Industry Exposure			493,232,880			

[1]Escalates to 25 percent on payout.
[2]R - rejected; A - accepted

Source: Alabama Dept. of Conservation and Natural Resources, 1997;
Alabama Oil and Gas Board, 1986

Table 3.5
1981 & 1982 Rejected State of Alabama Bids Compared to 1984 Bids

	1981-1982						1984						
State Block No.	Acreage	Bidder	Total Bonus	Bonus per Acre	Royalty %	Result	Acreage	Bidder	Total Bonus	Bonus per Acre	Royalty %	Result	Gain to State
114	4,782	Exxon	8,608,000	1,800	25	R	4,807	Exxon and Louisiana Hunt	52,984,000	11,022	16.67	A	44,376,000
92	5,164	Natomas	3,000,000	581	25	R	5,164	Exxon	39,672,000	7,680	16.67	A	36,672,000
93	4,823	Conoco, et al.	3,713,000	770	28.7	R	4,831	Exxon	39,364,000	8,148	20	A	35,651,000
64	5,164	Sunlite International, Inc.	581,040	113	26.1	R	5,165	Exxon	32,828,000	6,356	20	A	32,246,960
91	5,010	Pennzoil and Natomas	5,105,000	1,019	30	R	5,012	Exxon	16,540,000	3,300	20	A	11,435,000
97	3,217	Hunt and SOHIO	2,100,701	653	34	R	3,395	Exxon	14,634,000	4,310	16.67	A	12,533,299
117	3,479	Hunt and SOHIO	1,612,518	464	34	R	3,541	Exxon	14,428,000	4,075	16.67	A	12,815,482
73	3,690	Shell	5,674,000	1,538	25	R	4,795	Exxon	12,624,000	2,633	20	A	6,950,000
118	3,429	Exxon	1,102,000	321	25	R	3,669	Union and Pogo	9,310,000	2,537	16.67	A	8,208,000
88	5,112	Getty, Conoco, et al.	7,427,736	1,453	26.7	R	5,131	SOHIO	7,610,000	1,483	16.67	A	182,264
98	3,697	Hunt and SOHIO	2,101,745	569	34	R	3,652	Exxon	6,664,000	1,825	16.67	A	4,562,255
59	4,720	Getty, Conoco, et al.	722,160	153	25	R	4,665	Exxon	4,244,000	910	20	A	3,521,840
110	1,295	Getty, Conoco, et al.	2,878,000	2,222	25	R	1,295	MOEPSI, Getty & Conoco[1]	3,117,000	2,407	25	A	239,000
109	2,329	Sohio	852,577	366	25	R	2,511	Sohio	1,100,000	438	16.67	A	247,423
96	4,093	First Energy Corp.	5,751,000	1,500	25	R	4,093	Exxon	43,738,000	10,606	20	A	37,987,000
								Exxon Subtotal	*277,720,000*				*238,750,836*
		Total	**51,229,477**						**298,857,000**				**247,627,523**

Source: Alabama Dept. of Conservation and Natural Resources, 1997;
Alabama Oil and Gas Board, 1986

Exxon Exploration VP W. J. Wood was quoted in OGJ, "[Exxon] bid aggressively . . . because of its belief that the gas market will improve."[50] Seemingly, Mobil and Exxon had different views of the gas market, if not the geology. Tract 78 became part of Bon Secour Bay Field. The 1986 re-ordering of world energy prices cancelled any beliefs about improved market conditions.

Table 3.6
Comparison of 1984 Bids in State Sale #3
($ Million)

Tract	**Exxon**	**Mobil**
78	46.0	1.0
91	16.5	2.1
92	39.7	5.2
93	39.4	2.0
96	43.7	1.5
Total	185.3	11.8
Mobil % of Exxon		6.4%

Source: Table 3.4

3.5 OCS Lease Sale 98 - 1985

Disappointing March and April 1985 exploration results in federal tracts 826, 909, and 864 did not dampen enthusiasm for MMS Lease Sale 98, May 22, 1985. Table 3.2 shows that 20 tracts were acquired for $191.7 million in the Mobile OCS during this area wide sale in the Central Planning Region of the Gulf. The winning bids totalled nearly 90 percent more than the industry paid for 20 Mobile OCS tracts in the 1984 federal sale. The Conoco group acquired the highest bid tract of the entire sale, 991, which is in the Norphlet play, south of Mississippi. The highest bid three tracts of the entire sale, 991, 999, and 992 were Norphlet tracts. OGJ reported that Shell was the top bidder in the area wide sale, but Shell positioned itself in the deep water tracts of the Gulf and the Main Pass at the mouth of the Mississippi. Shell bid low on nine Mobile tracts and acquired none. Shell's only holdings in the Mobile area remained tracts 113 and 132. From an early position in Mobile Bay gas exploration, Shell shifted its focus to the deep water Gulf.[51]

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[50]OGJ, "Exxon leads spending in Mobile Bay lease sale," August 27, 1984, p. 30.

[51]Shell's deepwater discoveries to-date—Auger, Brutus, Bullwinkle, Cognac, Mars, Mensa, Popeye, Ram-Powell, Rocky, Tahoe, Tahoe II, and Ursa—confirm that Shell shifted its attention from the Norphlet to another frontier play that required exploitation of specialized, but different, technology from

Table 3.2 shows that Conoco, Amoco, and Sohio were the largest players in Norphlet tracts of Sale 98. Although Exxon only acquired three tracts, Exxon remained the largest lessee in Coastal Alabama. MOEPSI did not bid for new acreage in the sale. Chevron and Unocal added to their holdings on the eastern and western edges of the Alabama OCS Norphlet play.

3.6 State and Federal Coastal Alabama Sales: After 1985

Several small to moderate Coastal Alabama state and federal sales have occurred since 1985. Results are shown on Tables 3.7A and 3.7B. The state captured \$61.0 million more, mostly from MOEPSI for the lease of tract 75, which was subsequently drilled and unitized as the Aloe Bay Field. This brought the state's bonuses for lease sales to \$861 million.

A substantial amount of federal real estate in the Mobile Bay OCS changed hands after 1985 for only \$13.3 million, with Chevron and Union acquiring the bulk of it. This brought federal bonus collections to \$576 million from Coastal Alabama tracts.

Chevron leased federal tracts 819 and 820 for very low bids in 1988 when the "gas bubble" and low prices plagued the gas industry. Norphlet gas has been discovered under both 819 and 820; production ramped up in 1997. Conoco's \$51 million tract 991 from Lease Sale 98 was explored by Conoco, as will be discussed in the next section, and turned back to MMS. Chevron acquired it in Lease Sale 152 for \$2.6 million.

3.7 Industry Leases: 1997

By the end of 1997, industry had invested a total of \$1.4 billion in Coastal Alabama as shown on Table 3.8 by company. Exxon led the industry with \$573 million for 147,616 acres, including the highest price tract of all sales, tract 112 at \$137.3 million. Union and Chevron were the next largest individual lessees, holding between them more acreage than Exxon. Conoco and Sohio appear on the table as the fourth and fifth largest lessees, but their leases have mostly expired or otherwise changed hands.

Union and Chevron lead the Norphlet players in the lowest average price per acre under lease—\$757 and \$774. Getting a later start, they began leasing Norphlet tracts after gas prices had declined, spending at most \$23.6 million for tract 861, which proved to be a large Norphlet discovery. Union and Chevron spent twenty cents per acre for each dollar Exxon spent.

Figure 3.3 shows the leased positions as of 1995.

3.8 Alabama's Stake in the Bonus and Royalty Payments

The bonus payments collected in conjunction with offshore lease sales are a significant source of revenue to the State of Alabama. Bonus payments from the mid-1950s to 1979 came to just

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the Norphlet. See USDOI, MMS (1997), "Deepwater in the Gulf of Mexico: America's New Frontier," OCS Report MMS 97-0004, New Orleans, February 1997.

Table 3.7A
Leased Blocks in State of Alabama Waters, 1988 - 1997

Offshore Block no.	Lease Date	Original Lessee	Total Bonus $	Bonus per acre $	Rental per acre	Royalty
57	02/23/88	OGI[1]	646,000	500.29	2.50	20%
71	02/23/88	OGI[1]	646,000	500.29	2.50	20%
72	02/23/88	Callon[1]	225,000	174.25	2.50	20%
73	02/23/88	Callon[1]	1,536,000	1,251.20	2.50	20%
73	02/23/88	Callon[1]	265,000	205.23	2.50	20%
73	02/23/88	Callon[1]	988,000	1,003.22	2.50	20%
90	02/23/88	OEDC[1]	134,000	127.74	2.50	20%
90	02/23/88	Northern Michigan Expl. Co.	134,290	104.00	2.50	20%
91	02/23/88	ARCO	356,000	312.42	2.50	20%
91	02/23/88	OEDC[1]	165,000	127.91	2.50	20%
73	07/19/88	Shell/Amoco	3,873,000	807.72	5.00	16.67%
74	07/19/88	Shell/Amoco	4,373,000	1,138.21	5.00	20%
75	07/19/88	MOEPSI	25,178,000	10,189.40	5.00	25%
91	07/19/88	Shell/Amoco	843,000	168.20	5.00	16.67%
92	07/19/88	Shell/Amoco	8,377,000	1,621.88	5.00	16.67%
93	07/19/88	Shell/Amoco	10,388,000	2,150.28	5.00	16.67%
	Subtotal 1988		***58,127,290***			
60	12/29/93	MOEPSI	1,322,208	535.09		
61	12/29/93	MOEPSI	1,564,086	632.98		
110	12/29/93	BSFI Western E&P Inc.	12,950	5.24		
	Subtotal 1993		***2,900,417***			
71	12/10/97	MOEPSI	1,317,075	255.00		
88	12/10/97	MOEPSI	1,949,780	380.00		
89	12/10/97	MOEPSI	1,902,285	405.00		
90	12/10/97	MOEPSI	1,512,875	325.00		
	Subtotal 1997		***6,682,015***			
Total of State Leases			***67,709,722***			

[1] Formerly Arco

Source: Alabama Dept. of Conservation and Natural Resources, 1988; 1997.

Table 3.7B
Leased Blocks in the Alabama OCS, 1988-1997

Offshore Block no.	Original Lessee	OCS Lease Sale no.	Total Bonus $	Bonus per acre $
MO 819	Chevron	118	65,000	27.90
MO 820	Chevron	118	1,207,000	359.22
MO 910	Union	118	288,600	50.10
MO 954	Union	118	151,300	26.26
MO 859	Chevron/Union	123	146,000	25.34
MO 873	Murphy/ODECO	123	622,222	108.02
MO 909	Murphy/ODECO	123	994,444	172.65
MO 911	Union	123	73,440	25.50
MO 912	Murphy/ODECO	123	338,888	58.83
MO 913	Murphy/ODECO	123	458,888	79.67
MO 918	Chevron/Offshore Bechtel	123	175,800	30.52
MO 962	Union/Chevron/Offshore Bechtel	123	149,000	25.86
MO 826	Unocal/Offshore Bechtel	131	27,786	26.25
MO 871	Unocal/Chevron/Offshore Bechtel	131	201,600	35.00
MO 957	Unocal/Chevron/Offshore Bechtel	131	155,520	27.00
MO 866	OEDC	142	152,640	26.50
MO 874	Murphy	142	589,900	102.41
MO 956	Chevron/Offshore Bechtel	142	236,909	41.13
MO 902	MOEPSI	147	276,800	48.06
MO 944	Chevron	152	181,843	31.57
MO 987	Chevron	152	114,302	27.57
MO 988	Chevron	152	187,603	32.64
MO 991	Chevron	152	2,598,854	451.19
MO 992	Chevron	152	418,579	72.67
MO 993	Chevron	152	187,603	32.57
MO 1004	Union/Chevron/Offshore Bechtel	152	161,914	28.11
MO 1005	Union/Chevron/Offshore Bechtel	152	194,169	33.71
MO 1006	Union/Chevron/Offshore Bechtel	152	198,144	34.40
MO 873	Huntington Beach	157	329,875	57.27
MO 913	Chiefton	157	612,864	106.40
MO 1002	Vastar/Elf/Bechtel	157	227,900	39.57
MO 1003	Vastar/Elf/Bechtel	157	227,800	39.55
MO 946	Chevron	166	208,851	36.26
MO 951	Shell	166	178,000	30.90
MO 989	Zilkha	166	191,520	33.25
MO 997	Callon/Murphy/Santos	166	565,500	98.18
MO 998	Callon/Murphy/Santos	166	209,900	36.44
Total of Federal Leases 1988 - 1997			**13,306,958**	

Source: U.S. Dept. of the Interior, Minerals Management Service, 1998.

Table 3.8
Coastal Alabama Leases: 1997

Bidder	Lease Sale no.	Block No.	Acreage	Total Bonus Payments ($1000)	Bonus per Acre
Exxon					
	1	112	4,932	137,254	27,829
	1	111	1,687	53,168	31,516
	3	114	4,807	52,984	11,022
	3	78	4,980	45,972	9,231
	3	93	4,831	39,364	8,148
	3	64	5,165	32,828	6,356
	81	M 913	5,760	18,887	3,279
	3	116	3,254	18,323	5,603
	3	91	5,012	16,540	3,300
	1	63	5,164	15,226	2,948
	3	97	3,395	14,634	4,310
	3	117	3,541	14,428	4,075
	3	117	3,541	14,428	4,075
	3	73	4,795	12,624	2,633
	1	115	3,416	12,308	3,603
	1	62	5,164	10,522	2,038
	81	M 828	3,090	10,302	3,334
	1	52	5,164	9,112	1,765
	81	M 912	5,760	9,090	1,578
	67	M 867	5,760	6,747	1,171
	3	98	3,652	6,664	1,825
	3	59	4,665	4,244	910
	3	14	5,165	2,723	527
	81	M 829	2,775	2,424	873
	98	M 910	5,760	2,220	385
	3	119	2,945	1,820	618
	98	M 997	5,760	1,614	280
	98	M 957	5,760	1,510	262
	3	131/133	1,535	1,228	800
	67	M 866	5,760	1,211	210
	67	M 868	5,687	1,014	178
	81	M 911	5,760	909	158
	67	M 827	3,174	718	226
		Subtotal	147,616	573,040	3,882
Union, et al					
	1	90	4,612	21,879	4,744
	98	M 950	5,760	11,260	1,955
	98	M 874	5,760	9,750	1,693
	3	118	3,669	9,310	2,537
	98	M 948	5,760	5,137	892
	98	M 951	5,760	3,660	635
	98	M 949	5,760	2,875	499
	81	M 865	5,760	1,567	272
	81	M 860	5,760	1,351	235
	81	M 1003	5,760	989	172
	81	M 1002	5,760	989	172

Table 3.8 (continued)
Coastal Alabama Leases: 1997

Bidder	Lease Sale no.	Block No.	Acreage	Total Bonus Payments ($1000)	Bonus per Acre
Union, Cont'd	72	M 904	5,760	900	156
	69	M 905	5,760	882	153
	94	P 837G	2,828	454	161
	118	M 910	5,760	289	50
	118	M 954	5,762	151	26
	123	M 962	5,762	149	26
	123	M 911	2,880	73	26
	152	M 1004	5,760	162	28
	152	M 1005	5,760	194	34
	152	M 1006	5,760	198	34
		Subtotal	111,913	72,219	645
Chevron, Union and Pennzoil					
	67	M 861	5,198	23,616	4,543
	67	M 862	5,618	17,616	3,135
	72	M 961	5,760	2,572	447
	67	M 906	5,760	2,110	366
	72	M 916	5,760	1,300	226
	72	M 958	5,760	1,300	226
	72	M 915	5,760	1,300	226
	72	M 917	5,760	1,227	213
	118	M 820	3,360	1,207	359
	142	M 956	5,760	237	41
	123	M 918	5,760	176	31
	123	M 859	5,762	146	25
	118	M 819	2,330	65	28
	152	M 944	5,760	182	32
	152	M 987	4,146	114	28
	152	M 988	5,748	188	33
	152	M 991	5,760	2,599	451
	152	M 992	5,760	419	73
	152	M 993	5,760	188	33
	166	M 946	5,760	209	36
		Subtotal	107,041	56,769	530
Conoco, Amoco, Getty & Pennzoil					
	98	M 991	5,740	51,096	8,902
	98	M 992	5,760	20,325	3,529
	98	M 956	5,760	11,768	2,043
	98	M 871	5,760	7,657	1,329
	79	P 969	5,760	1,515	263
	79	P 970	5,760	1,214	211
	81	M 996	5,760	1,108	192
	79	P 881	5,760	957	166
	81	M 995	5,760	918	159
		Subtotal	51,820	96,558	1,863

Table 3.8 (continued)
Coastal Alabama Leases: 1997

Bidder	Lease Sale no.	Block No.	Acreage	Total Bonus Payments ($1000)	Bonus per Acre
SOHIO, et al					
	3	89	4,811	42,712	8,878
	98	M 999	5,760	27,137	4,711
	98	M 1000	5,760	12,625	2,192
	3	88	5,131	7,610	1,483
	98	M 1001	5,760	5,127	890
	98	M 994	5,760	4,256	739
	98	M 998	5,760	3,712	644
	98	M 993	5,760	3,471	603
	67	M 821	4,028	3,000	745
	3	109	2,511	1,100	438
		Subtotal	51,041	110,750	2,170
MOEPSI, et al					
	67	M 779, 823, 824	5,585	55,119	9,856
	67	M 778, 822	5,324	45,117	8,471
	1	71	4,196	40,425	9,634
	1	72	5,164	31,535	6,107
	4	75	2,471	25,178	10,189
	2	110	1,295	3,117	2,407
	1993	61	2,471	1,564	633
	1993	60	2,471	1,322	535
	1969	77	5,165	26	5
	1969	76	5,053	21	4
	1969	95	4,322	20	5
	1969	94	5,155	12	2
	1997	71	5,165	1,317	255
	1997	88	5,131	1,950	380
	1997	89	4,697	1,902	405
	1997	90	4,655	1,513	325
	147	M 902	5,759	277	48
		Subtotal	74,079	210,415	2,840
Texaco (Getty), et al					
	81	M 869	4,503	32,078	7,123
	81	M 962	5,760	6,818	1,184
	81	M 1005	5,760	3,518	611
	81	M 872	5,760	3,518	611
	81	M 1006	5,760	3,037	527
	81	M 873	5,760	2,518	437
	81	M 918	5,760	1,617	281
	81	M 830	2,909	1,518	522
		Subtotal	41,973	54,622	1,301
Shell					
	1	113	5,123	34,370	6,709

Table 3.8 (continued)
Coastal Alabama Leases: 1997

Bidder	Lease Sale no.	Block No.	Acreage	Total Bonus Payments ($1000)	Bonus per Acre
Shell, Cont'd	67	M 909	5,760	28,277	4,909
	1	132	2,367	22,435	9,478
	4	93	4,831	10,388	2,150
	4	92	5,165	8,377	1,622
	4	74	3,842	4,373	1,138
	4	73	4,795	3,873	808
	4	91	5,012	843	168
	166	M 951	5,761	178	31
		Subtotal	42,656	113,114	2,652
ODECO, et al					
	72	M 952	5,760	5,667	984
	72	M 955	5,760	4,778	830
	72	M 953	5,760	3,642	632
	94	P 971	5,760	1,020	177
	94	P 925	5,760	1,020	177
		Subtotal	28,800	16,127	560
Murphy/ODECO					
	123	M 909	5,760	994	173
	123	M 873	5,760	622	108
	142	M 874	5,760	590	102
	123	M 913	5,760	459	80
	123	M 912	5,760	339	59
		Subtotal	28,801	3,004	104
ARCO, et al					
	67	M 908	5,760	24,198	4,201
	72	M 959	5,760	5,553	964
	72	M 960	5,760	1,053	183
	81	M 1004	5,760	920	160
	4	91	1,139	356	312
		Subtotal	24,179	32,080	1,327
Unocal/Offshore Bechtel					
	131	M 826	1,059	28	26
	142	M 866	5,760	153	27
	131	M 957	5,760	156	27
	131	M 871	5,760	202	35
		Subtotal	18,339	538	29
Tenneco, et al					
	72	M 863	5,760	7,930	1,377
	67	M 864	5,760	4,880	847
	98	M 907	5,760	1,459	253
		Subtotal	17,280	14,269	826

Table 3.8 (continued)
Coastal Alabama Leases: 1997

Bidder	Lease Sale no.	Block No.	Acreage	Total Bonus Payments ($1000)	Bonus per Acre
Placid					
	67	M 870	5,618	5,085	905
	72	M 826	1,430	3,564	2,492
		Subtotal	7,048	8,648	1,227
Santa Fe and HNG					
	98	M 914	5,760	5,076	881
Callon					
	4	73	1,228	1,536	1,251
	4	73	985	988	1,003
	4	73	1,291	265	205
	4	72	1,291	225	174
	166	M 997	5,760	566	98
	166	M 998	5,760	210	36
		Subtotal	16,315	3,789	232
OGI					
	4	57	1,291	646	500
	4	71	1,291	646	500
		Subtotal	2,583	1,292	500
OEDC					
	4	90	1,049	134	128
	4	91	1,290	165	128
	142	M866	5,760	153	27
		Subtotal	8,099	452	56
Northern Michigan Exp. Company					
	4	90	1,291	134	104
BSFI Western E&P Inc.					
	1993	61	2,471	13	5
Miscellaneous Operators					
	157	M 873	5,760	330	57
	157	M 913	5,760	613	106
	157	M 1002	5,759	228	40
	157	M 1003	5,760	228	40
	166	M 989	5,760	192	33
		Subtotal	28,799	1,590	55
Total			817,903	1,374,499	1,681

Source: Foster Associates, Inc. 1997; Alabama Dept. of Conservation and Natural Resources, 1997; Alabama Oil and Gas Board, 1986

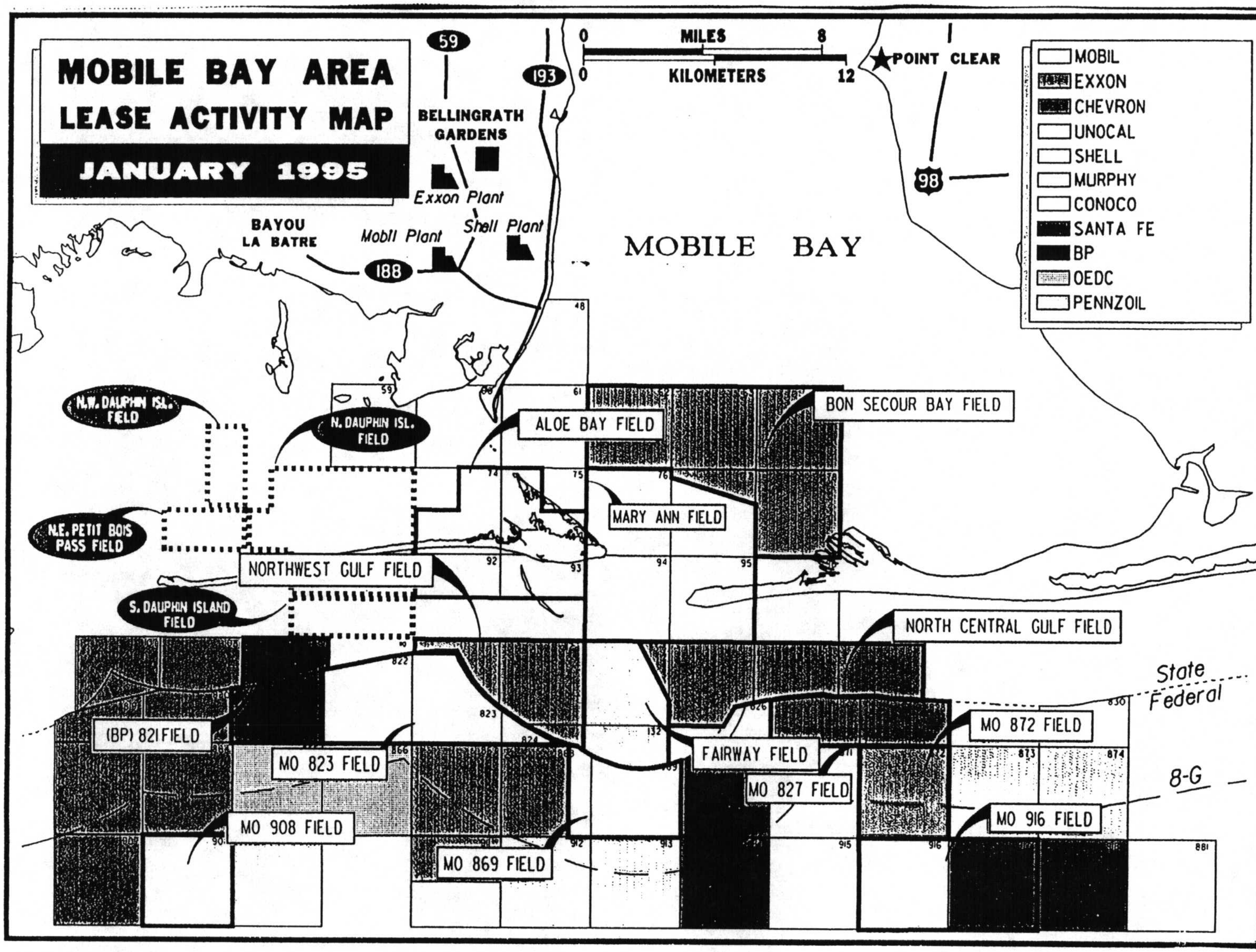

Figure 3.3. Mobile Bay Area Lease Activity Map, January 1995.

Source: MOEPSI, 1997.

over $500,000; bonus payments since 1979 total $868 million from four lease sales since gas was discovered in Mobile Bay in 1979: 1981, 1982, 1984, and 1988. By far the largest bonus collections, almost $450 million, occurred in 1981. Only one bid was accepted in the 1982 lease sale, garnering almost $3.2 million. The 1984 sale collected bonus payments of almost $350 million. In 1988, Alabama received about $58 million; three tracts were leased in 1993 for $3.0 million; four tracts were leased in 1997 for $6.7 million.

After the 1981 lease sale, Alabama politicians were bedazzled by the bonus bonanza, which they viewed as a "one-time thing. . . . a once in a lifetime opportunity to solve the majority of problems facing the State of Alabama, Governor [Fob James] said" in April 1981. Governor James articulated a list of capital projects from prisons to bridges and a controversy emerged as to how to spend the money.[52] The Senate approved a resolution by Senator H. L. "Sonny" Callahan of Mobile "to set the money aside in an invested trust fund and spend only the . . . interest. . . . [leaving] a legacy for the future. . . . Governor James expressed 'serious reservations' about the Callahan proposal at a later press conference."[53] Governor James subsequently proposed to the state legislature that a perpetual trust fund be established to ensure that the State of Alabama would continue to benefit from the bonus proceeds.

3.8.1 Trust Funds Preserve Money for the Future

The Heritage Trust Fund was established after the 1981 lease sale (March 17, 1982). Provisions of the trust fund require that only the interest be distributed for statewide use. A second fund, the Alabama Trust Fund, was ratified December 10, 1984 following the 1984 lease sale. At that time all future royalty payments were directed to the Alabama Trust Fund, with provisions similar to the earlier fund—that only the annual interest accrued could be spent. In 2001 the Heritage Trust Fund will be rolled into the Alabama Trust Fund so that only one fund is maintained.

In FY 1996, the corpus balance of the Heritage Trust Fund was almost $467 million. Table 3.9 shows that the Alabama Trust Fund capital balance stood at about $874 million, having grown with the receipt of state royalty payments and the state's 27 percent share of 8(g) federal royalty payments from producing federal leases within 8 miles of Alabama land. Since 1986, the annual interest from both funds averaged near $100 million.[54] The majority of annual interest earned is transferred into the state's General Fund, where it has amounted to between 11 - 12 percent of the state's General Fund budget in recent years.

Beginning with fiscal year 1992-1993, a percentage of interest earned from the Alabama Trust Fund is transferred to the Forever Wild Trust Fund, a fund established as part of the Forever Wild Program for the acquisition of lands for public use. In FY 1993 payments to the fund

[52]"Storm brewing over fate of lease funds," Birmingham *Post Herald*, April 3, 1981.

[53]"Storm brewing over fate of lease funds," Birmingham *Post Herald*, April 3, 1981.

[54]Alabama Dept. of Conservation and Natural Resources, 1997.

Table 3.9
State of Alabama Oil and Gas Trust Fund Balances and Interest Earned
(Millons $)

Fiscal Year	Alabama Trust Fund Corpus Balance	Heritage Trust Fund Corpus Balance	Total Corpus Balance of Trust Funds	Alabama Trust Fund Interest to GF	Heritage Trust Fund Interest to GF	Total Trust Fund Interest to GF	Forever Wild Trust Fund Payments
1984-1985	$334.0	$479.8	$813.8	$7.8	$66.7	$74.5	--
1985-1986	$399.9	$479.8	$879.7	$39.8	$61.0	$100.8	--
1986-1987	$400.6	$479.8	$880.4	$39.2	$59.9	$99.1	--
1987-1988	$455.2	$479.8	$935.0	$39.0	$58.8	$97.8	--
1988-1989	$460.2	$467.3	$927.5	$45.3	$60.8	$106.1	--
1989-1990	$465.9	$466.8	$932.7	$44.9	$54.4	$99.3	--
1990-1991	$472.1	$466.8	$938.9	$44.7	$60.8	$105.5	--
1991-1992	$501.2	$466.8	$968.0	$42.7	$50.9	$93.6	--
1992-1993	$571.5	$466.8	$1,038.3	$41.8	$55.7	$97.6	$1.8
1993-1994	$677.7	$466.8	$1,144.5	$40.6	$51.8	$92.4	$2.1
1994-1995	$757.4	$466.8	$1,224.2	$47.5	$51.9	$99.4	$3.0
1995-1996	$873.6	$466.8	$1,340.4	$50.6	$51.8	$102.4	$3.8

Source: Alabama Dept. of Conservation and Natural Resources, 1997.

totalled $1.8 million; payments increased to $3.8 million in FY 1996. After FY 1998, 10 percent of the annual earnings from the Alabama Trust Fund will be directed to Forever Wild, not to exceed $15 million in any fiscal year.

3.8.2 Royalty Payments Have Added to Alabama Trust Fund

Royalty payments to the state totalled $354 million through year end 1996 as shown on Table 3.10. Norphlet production accounted for $301 million, with Exxon providing the most, $147 million, and Shell second at $113 million. Miocene royalty payments amounted to only $17 million. Federal 8(g) payments amounted to $36 million by year end 1996. These payments include production from the federal share of BP's 821 Field, MOEPSI's 823 Field, and Exxon's 827 Field. These will increase in 1997 to reflect MOEPSI's production from the 869 Field and Chevron's production from tracts 819, 820, 863 and 864.

Table 3.10
Annual Royalty Payments to Alabama
($1000)

Calender Year	Exxon/Hunt	MOEPSI	BP	Shell/ Shell Amoco	Norphlet Subtotal	Fiscal Year	Miocene Subtotal	8g Federal Waters	Total
1988		1,540			1,540	87-88		250	**1,790**
1989		3,350			3,350	88-89		710	**4,060**
1990		1,020			1,020	89-90		n/a	**1,020**
1991		4,193		487	4,680	90-91		300	**4,980**
1992		2,741	62	2,070	4,874	91-92	1.35	1,560	**6,435**
1993	469	8,010	288	36,789	45,555	92-93	31	6,560	**52,146**
1994	53,119	6,160	318	31,741	91,337	93-94	5,268	8,330	**104,936**
1995	40,504	5,355	135	20,948	66,942	94-95	7,700	7,370	**82,012**
1996	53,081	7,462	198	21,391	82,132	95-96	4,072	10,945	**97,150**
Total	**147,173**	**39,831**	**1,000**	**113,426**	**301,430**		**17,074**	**36,025**	**354,529**

Source: Alabama Dept. of Conservation and Natural Resources, 1997.

4.0 Exploration Expands Beyond Mary Ann Field

Following the 1979 Mary Ann discovery well, 76-1, MOEPSI and Exxon drilled 11 more successful gas wells in a row. By year end 1984, MOEPSI and Exxon, having discovered five Norphlet reservoirs plus Lower Mobile Bay, had proved that Mobile Bay would become one of the most significant gas producing provinces in the U.S. Exxon and Chevron added two other discoveries in 1985. Table 4.1 catalogs wells as exploration or delineation and shows the fields discovered through 1985. Seventeen Norphlet wells were spudded and tested by year end 1985 taking between six and twelve months each to drill 21,000+ feet wells.

Table 4.1
Norphlet Exploration and Delineation Wells: 1979 - 1985

Operator	Delineation	Exploration	Discovered Fields	Discovery Date
MOEPSI	94-2, 95-1,	76-1	Mary Ann	
	77-1, 76-2, 77-2	823-1	Field	11/28/79
		72-1	823 Field	9/4/83
			West Dauphin	
			Island Field	2/24/84
Exxon	63-1	62-1	Bon Secour	
		913-1	Bay Field	9/23/83*
		867-1	867 Field	7/26/84
		112-1	Northwest	
			Gulf Field	12/25/84
		115-1	North Central	
			Gulf Field	4/12/85
Chevron		861-1	861 Field	8/12/85
Placid		826-1		
Shell		909-1		

*Officially discovered with 63-1 8/29/84.
Source: Table 4.2

Rick Hagar, Gulf Coast Editor of OGJ, who covered the news about Mobile Bay in the 1980s, wrote a long status report in the January 14, 1985 issue. Hagar speculated that reserves discovered to date amounted to about 2.5 TCF, with the federal 823 Field being the largest—at least 1 TCF recoverable. Hagar described the 823 structure as possibly reaching from tract 867 to tract 112. Exxon Exploration V.P. Stephen M. Cassiani, called their success "phenomenal," having hit three gas wells on four plays. He described Exxon's development plans in the "infant stages" and Cassiani speculated that "the offshore Norphlet trend may someday surpass Prudhoe Bay's 26 TCF."[55]

4.1 MOEPSI Mary Ann Delineation: 1981 & 1982

MOEPSI, having initiated its lower Mobile Bay appraisal program in January 1981, jointly applied to the Corps of Engineers in August with four other winners in Alabama's March lease sale for permission to drill up to 28 deep wells to explore their leased acreage.[56] The program was described as a five year effort in documents submitted to the Corps in August 1981. State officials—other than Mr. Baxley, who ran for governor in 1978 with environmental backing and lost—happy with the $449 million in the bank earning nearly $160,000 a day in interest, strongly endorsed the proposed drilling plan.

MOEPSI's four appraisal wells, 94-2, 95-1, 77-1 and 76-2 were the only wells spudded in 1981 and 1982 as the regulatory agencies reviewed the submitted program. Mrs. Myrt Jones resumed her public stance against drilling in Mobile Bay, keying her remarks at a public hearing in July 1981 against Exxon. She sought evidence that the industry had prepared "a 'fast response' plan to handle oil spills and hydrogen sulfide leaks, using equipment locally available."[57] Both of these are part of the standard response measures.

4.2 Exploration and Delineation Drilling: 1983 - 1985

Exxon was the first of the new group to initiate drilling—but not until January 1983. Four Norphlet wells were spudded in 1983 and seven were spudded in 1984. Six of these 11 were drilled by Exxon. Wells spudded before year end 1984 are shown on Table 4.2.

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[55]OGJ, "Mobile Bay shaping up as major gas producing area," January 14, 1985, p. 25.

[56]OGJ, "Mobile Bay wildcat drilling programs outlined," August 17, 1981, p. 80-81.

[57]"Coastal drilling plans shape up," Mobile *Press*, June 23, 1981.

Table 4.2
Mobile Bay Norphlet Wells Drilled 1979 - 1985

Tract	Operator	Well	Permit Date	Test Date	Status 1/85	Status 12/97
76	MOEPSI	76-1	6/21/78	11/28/79	gas well	Producing
94	MOEPSI	94-2	2/2/81	5/22/82	gas well	Producing
95	MOEPSI	95-1	1/28/81	8/22/82	gas well	P&A
77	MOEPSI	77-1	7/6/82	3/27/83	gas well	Producing
823	MOEPSI	823-A1	4/14/83	9/4/83	gas well	Producing
62	Exxon	62-1	11/30/82	9/23/83 TA not tested until 6/2/85	gas well	Producing
72	MOEPSI	72-1	7/13/83	2/24/84	gas well	P&A
867	Exxon	867-1	3/14/84	7/26/84	gas well	TA; complete in 98
76	MOEPSI	76-2	10/22/82	not tested until 6/29/88	gas well	P&A
77	MOEPSI	77-2	8/26/83	not tested until 6/13/87	gas well	Producing
63	Exxon	63-1	3/14/84	8/29/84	gas well	Producing
112	Exxon	112-1	5/30/84	12/25/84	gas well	Producing
826	Placid	826-1/826-2ST	12/16/83	3/5/85	drilling	P&A (water)
909	Shell	909-1	11/3/84	3/12/85	drilling	P&A
115	Exxon	115-1	9/11/84	4/12/85	drilling	Producing
913	Exxon	913-1	11/13/84	7/13/85	drilling	P&A
861	Chevron	861-1	11/4/84	capped 7/85	drilling	Gas well; blew out, 4/85 -P&A

Source: Alabama Oil and Gas Board, 1997; U.S. Dept. of the Interior, MMS, 1998.

4.2.1 Exxon Steps Out in State Water: 1983 and 1984

Exxon was permitted to drill its first well seeking Norphlet gas on November 30, 1982 and spudded a well on state tract 62 in January 1983 in 14 feet of water targeted to 21,000 feet. The well was three miles north-northeast of Mobil's discovery well. Well 62-1 was drilled to target depth on September 6, 1983, but not tested until June 1985. The well tested 20.5 MMCFD at 20,822 feet as the confirmation of the Bon Secour Bay field. Exxon well 63-1, spudded March 14, 1984 and tested 28.1 MMCFD at 20,792 feet on August 29, 1984 is the official discovery well.

Tract 112, for which Exxon paid $137 million, was not permitted until May 30, 1984. The well tested 21.1 MMCFD on December 25, 1984. Well 112-1 discovered the Northwest Gulf Field at a depth of 21,500 feet. Exxon's aggressive bids in the August 1984 state Lease Sale reflected the information they acquired from their drilling program.

Exxon hit another winner—115-1—in April 1985 giving Exxon four successful state gas wells. Well 115-1 discovered the North Central Gulf Field at a depth of nearly 21,400 feet. The well tested 9.0 MMCFD.

4.2.2 MOEPSI Finds the First Federal Field

MOEPSI's drilling during 1983 and 1984 included two exploration wells (823-A1 and 72-1) and two more delineation wells in the Mary Ann field (76-2 & 77-2). MOEPSI completed its 77-1 well in April 1983 and moved the drilling rig, a Global Marine jack up, to federal tract 823—the first federal acreage to be probed and the first discovery in federal water. The well tested 26 MMCFD April 14, 1983, encountering gross sand thickness of 300 to 700 feet at a depth of up to 1,100 feet deeper than Mary Ann. Federal tract 823 adjoins Exxon's tract 111.

Exxon followed this with a discovery March 14, 1984 in tract 867, adjoining the southern edge of Mobil's tract 823. The well, drilled to 22,422 feet, tested 33 MMCFD, the highest flow rate recorded to date in the Norphlet. Exxon described the discovery as a possible extension of the reservoir underlaying 823. Exxon subsequently drilled a well in adjoining tract 868 that was tested on February 21, 1986, then plugged and abandoned (P&A'd). No development has occurred on 867 although the lease is still active. Exxon maintains that they will produce the 867 gas in 1998.[58]

MOEPSI's third discovery was on state tract 72, north of Dauphin Island and 10 miles west of their first discovery well on tract 76. This well tested 21.2 MMCFD from 21,102 feet on February 24-25, 1984 from the uppermost perforation, having tested water at lower depths. The West Dauphin Island Field was established in September 1985 consisting of tracts 71, 72, 89 and 90. The south half of 89 and 90 subsequently were deleted from the field because Union's well

[58]Telcon with Exxon executive, May 5, 1997.

90-1 was P&A'd as non-productive in July 1986. Union "twisted off leaving 50 feet of bottom hole assembly fish in the hole."[59]

MOEPSI appeared before the AOGB in December 1987 seeking another reduction of field limits to match extensive new 3D seismic evidence that showed that the West Dauphin Island Field was smaller than originally believed. Ultimately, MOEPSI turned the leases back to the state in 1994. The tight zone found in all Norphlet producing reservoirs varies greatly in thickness but is perhaps the thickest in the Alabama Well 72-1 where it reaches a thickness of 141 feet. Average pay thickness is 67 feet. MOEPSI found that the Well 72-1 tight zone is too thick, the structure is too small, and the net pay is too thin to sustain development.

4.2.3 Chevron Pioneers the Western Norphlet Trend

Chevron's first Norphlet well was drilled in tract 861 and tested 11.2 MMCFD at 21,645 feet. The well was 18 miles west of Exxon's discovery in tract 867, and 14 miles south of Pascagoula. The well encountered bottomhole pressure greater than 18,000 psi, well above previous Norphlet discoveries in the 10 - 13,000 psi range. The well blew out underground in April 1985 and was subsequently capped in July, plugged and abandoned. Chevron subsequently drilled a number of Miocene wells and one well to 11,500 feet in tract 861. They finally drilled a second Norphlet well in tract 861 to 22,103 feet seven years later, testing 52 MMCFD on April 9, 1991.

4.2.4 First Disappointments: 1984 & 1985

After hitting 12 gas wells in row, Placid's 826-1 well was the first Norphlet disappointment. The well was P&A'd March 5, 1985 after two sidetracks. This proved that Exxon's tract 115 discovery was sealed on the south by a fault between the state and federal tracts. Placid drilled a well and two sidetracks into this small tract beginning in December 1983 before finally giving up in April 1985. Exxon, a partner in the well, subsequently testified to the AOGB that the well encountered 100 percent water from an interval in the Norphlet that was hoped to contain gas.[60]

Four of the five wells drilling January 1, 1985 were disappointments. These included Shell's first Norphlet well, drilled in tract 909, tested March 12, 1985 and Exxon's well 913-1, tested July 13, 1985. Shell drilled its tract for which it paid $28.2 million in Sale 67 before it drilled its state tracts 113 and 132, which it acquired in 1981. Shell's and Exxon's wells were below 22,000 feet, following the downward dip of the sands. Shell's and Exxon's leases were subsequently terminated, the wells plugged and abandoned. These well results suggest that the productive Norphlet does not extend very far directly south of the entrance to Mobile Bay.

[59]AOGB Docket 12-17-879A, p. 74.

[60]AOGB Docket 9-6-86, p. 79.

4.2.5 Summary: Exploration Successes: 1983 - 1985

Through 1985, Mobile Bay operators had discovered eight Norphlet fields. Exxon's four discoveries led to the establishment of three producing state fields and one federal field—Bon Secour Bay, North Central Gulf, 827 Field, and Northwest Gulf—which produced between about 320-408 MMCFD in 1997. So far, Exxon has produced no gas from tract 867. MOEPSI's exploration found the 823 Field, which produced as much as 200 MMCFD in 1996, and the West Dauphin Island Field, which was abandoned in 1994. Chevron's discovery led to substantial exploration by Chevron and Union in the vicinity of the 861 discovery, after technical problems were solved to deal with the extremely high reservoir pressures. Production is building up in 1998 from Chevron's 861 tract and wells in adjoining tracts.

4.3 Exploration and Delineation Wells: 1985 - 1989

Twenty-two Norphlet wells were spudded and tested between 1985 - 1989. Most were spudded before gas prices skidded below $2.00 in 1986. Oil prices collapsed at that time, bringing the value of liquid btus in line with natural gas btus, and confirming that the incentives for spudding $20 million exploration wells needed to be reconsidered. The activity in 1985 and 1986 was both planned earlier and needed to be undertaken to comply with five year lease terms from the first state and federal lease sales. Nine wells were spudded after the oil price drop. Exploration slowed considerably during 1988 and 1989.

Twelve of the 22 wells were delineation wells, seven of which drilled by Exxon; ten were exploration wildcats drilled by MOEPSI and the new participants. Table 4.3 shows the wells characterized as delineation or exploration and fields discovered. Seven new fields were discovered bringing the total number of discovered Norphlet fields to 15 by the end of 1989. Table 4.4 shows the wells in date order of their testing.

Table 4.3
Norphlet Exploration and Delineation Wells Drilled: 1985 - 1989

Operator	Delineation Wells	Exploration Wells	Discovered Fields	Discovery Date
Exxon	64-1, 78-1, 114-1, 868-1, 827-1, 97-1, 91-1		827 Field	4/21/86
MOEPSI	823-A2, 822-1, 822-2			
BP		821-1, 999-1	821 Field	4/10/86
Shell	132-1	113-1	Fairway Field	5/2/86
Chevron	862-1	DD56-1	Destin Dome	1/7/88
Texaco		1006-1, 872-1, 869-1	872 Field 869 Field	7/24/88 8/22/89
Union		90-1, 904-1	904 Field	5/18/88
Conoco		991-1		

Source: Table 4.4.

Table 4.4
Mobile Bay Norphlet Wells Spudded and Tested: 1985 - 1989

Tract	Operator	Well	Permit Date	Test Date	Status 1/89	Status 12/97
822	MOEPSI	822-1	1/10/85	9/24/85	P&A	P&A
64	Exxon	64-1	5/24/85	11/8/85	gas/TA	P&A March, 1997
114	Exxon	114-1	1/14/85	12/14/85	gas/TA	P&A
1006	Texaco	1006-1	2/27/85	1/8/86	P&A	P&A
868	Exxon	868-1	8/1/85	2/21/86	P&A	P&A
821	BP	821-1	9/25/85	4/10/86	gas/TA	Producing
113	Shell	113-1	2/15/85	5/2/86	gas/TA	Producing
97	Exxon	97-1	6/13/85	7/16/86	P&A (water)	P&A
90	Union	90-1	12/4/85	7/21/86	P&A (water)	P&A
827	Exxon	827-1	4/1/86	7/29/86	gas/TA	Producing
862	Chevron	862-1	11/9/86	5/21/87	gas/TA	TA;ST, 1998
991	Conoco	991-1	10/16/86	10/28/87	P&A	P&A
91	Exxon	91-1	4/30/85	12/27/87	P&A (water)	P&A
DD56	Chevron	DD56-1	6/12/87	1/7/88	gas/TA	P&A
999	BP	999-1	4/22/87	2/17/88	P&A	P&A
822/ 110	MOEPSI	822-2/ 110-1	8/7/87	5/10/88	P&A	P&A
904	Union	904-1	9/21/87	5/18/88 (bottomhole)	gas/TA; Test 97.6 MMCFD 2/92	start up 12/93; lost the well 8/94
872	Texaco	872-1	11/16/87	7/24/88	gas/test at 25 MMCFD	Producing
132	Shell	132-1	9/17/87	11/27/88	gas	Producing
823	MOEPSI	823-A2	7/23/88	4/7/89	gas/TA	Producing
869	Texaco	869-1	10/7/88	8/22/89	drilling	Gas;P&A
78	Exxon	78-1	12/1/88	12/13/89 (bottomhole)	drilling	Producing

Source: Alabama Oil and Gas Board, 1997; U.S. Dept. of the Interior, MMS, 1998.

4.3.1 Exxon Delineates Discoveries

Four of Exxon's wells extended their discoveries—64-1 and 78-1 extended the Bon Secour Bay Field; 114-1 and 827-1 extended the North Central Gulf reservoir limits. The 827 gas well resulted in the formation of federal 827 Field. The wells in state tracts 91 and 97 hit water to the north of their 111 and 115 discoveries, and the well in 868 must have confirmed that the 823 reservoir did not trend southeast quite as far as originally anticipated. Unlike the 867 discovery, 868-1 was P&A'd. Well 114-1 found gas, but tested only 1.2 MMCFD due to poor quality (low permeability) reservoir rock. Exxon later decided with 3D seismic that 114-1 penetrated a thin section of interdune reservoir. Well 114-2 subsequently penetrated the thick center of the dune containing good quality reservoir rock in 1991, after which 114-1 was P&A'd in 1992.[61] Well 114-2 typically produces about 35 MMCFD.

4.3.2 Texaco Finds Federal 869 and 872 Reservoirs

Texaco's well 872-1 tested 25 MMCFD gas at 22,803 feet in July 1988. Confirming the typical northwest-southeast orientation of Norphlet sands, the well is southeast of the Exxon discovery wells on tracts 115 and 827. Chevron subsequently purchased the 872 discovery from Texaco. Chevron's infrastructure plans for the eastern area of the Mobile OCS supported the purchase. Well 872-1 initiated production March 1996, producing to Union's 916 platform.

Texaco drilled well 869-1 and discovered reserves south of Shell's Fairway Field in August 1989 at 22,635 feet. The well tested only 5.1 MMCFD, suggesting that it wasn't in a very good location in the reservoir. Texaco, which acquired the lease when it merged Getty, subsequently sold the discovery to Mobil because Texaco had no infrastructure and insufficient discoveries to justify development pipelines and processing. Mobil's well later hit a more productive part of the reservoir and the field started production February 1997 from well 869-3 at 80 MMCFD transported to the 823 plant.

Texaco's two discoveries are producing nearly 75 MMCFD in 1997.

4.3.3 MOEPSI's 823 Delineation Efforts

MOEPSI drilled a confirming gas well on its 823 discovery and two wells—822-1, 822-2—looking for the western extension of the 823 reservoir. Well 822-1 was a straight hole, but 822-2 reached a bottom hole in tract 110. Neither of the two found commercially productive Norphlet gas.

4.3.4 BP Finds Federal Field 821

BP's successful well in 821 discovered a new reservoir, rather than a westward trend of the 823

[61]AOGB Docket 11-9-937, p. 287.

reservoir. BP's well subsequently began production in January 1992, producing over 20 MMCFD, processed on the platform. BP had only the single discovery and sold the producing property to Shell August 1, 1996. Shell may drill another well on the tract sometime in 1998.

4.3.5 Shell Finds Fairway Field

Shell's well 113-1 discovered the Fairway Field May 2, 1986 at 21,200 feet. The well tested 13.7 MMCFD. Well 132-1 confirmed the extent of the reservoir November 27, 1988. The Fairway Field was subsequently developed with four wells producing in 113 and one in 132. The 113-1 well was reported by Shell Offshore General Manager of Production, W. W. Dover, as penetrating 500 feet of net pay gas.[62] Porosity averages 13 percent in the reservoir and average pay thickness is 199 feet. Like other Norphlet fields, the Fairway Field has variable H_2S, close to 100 ppm for some of the wells and up to 1.5 percent for others.

4.3.6 Chevron/Union Confirm Western Edge Norphlet Trend

Chevron's well 862-1 found gas, delineating their adjoining 861 discovery, and confirming that the Norphlet trends east-west between the Alabama and the Mississippi OCS. The well remains TA, tentatively scheduled for a sidetrack in 1998. Union's 904-1 discovery southwest of 861 provides evidence of the extent of the productive Norphlet on the western trend of the Norphlet. Union's 904-1 well reached total depth in 1988 but was not tested until February 1992 due to technology limitations on the extremely high pressure gas. The well tested 97.6 MMCFD, the highest rate to date, from 22,290 feet in February 1992. Union's well encountered as much as 20,000 psi—the same problem Chevron encounter with its 861-1. Chevron and Union sought delays from MMS while they developed metallurgy technology to deal with the extremely high pressures.[63] The well was finally brought into production December 1993; but the well was lost in August 1994.

Union's state well 90-1 was water bearing, proving that a fault separated the tract from MOEPSI's discovery on tract 72. This was a major disappointment.

4.3.7 Chevron Hits Destin Dome

The major discovery of the five year period was Chevron's discovery of the Norphlet 22 miles south of Pensacola Beach in the Destin Dome OCS. Well DD56-1 was not tested but "analysis of cores and . . . logs indicated the presence of gas in the Norphlet sandstone"[64] January 7, 1988 at 22,572 feet. After years of unsuccessful exploration of the Eastern Gulf by the industry, Chevron is fulfilling the geologic potential subsequently described by Mink, Tew, et al.[65] The

[62]OGJ, "Development activity dots Mobile Bay trend," April 6, 1987, p. 27.

[63]OGJ, "Industry slates more exploration, development in the Gulf Norphlet," March 6, 1989, p. 16

[64]OGJ, "Norphlet gas find indicated off Pensacola," February 21, 1989, p. 18.

[65]Mink, Tew, et al, Bulletin 140, 1990, p. 23 - 26.

Norphlet extends east from Mobile Bay. After two subsequent delineation wells, Chevron filed a Development and Production Plan with MMS in December 1996, calling for an expected production of 300 MMCFD on peak, not long after the turn of the century. This discovery put Murphy and Conoco into the game as Chevron's equal partners.

4.3.8 Conoco/BP/Texaco Disappointments

Conoco's and BP's two wells in their expensive federal Sale 98 tracts—991 and 999—provide evidence of their efficiency in planning, permitting and initiating exploration programs; but their disappointments provide further evidence that the productive Norphlet does not run too far directly south of Mobile Bay, even dipped to the greater depths where these wells bottomed: 23,195 and 24,274 feet. Well logs show that Conoco's 991-1 well actually hit extremely good quality gas bearing sand; but the well was in a thin location, penetrating a 30 foot pay zone, possibly interdune. Conoco P&A'd and let the lease expire. Chevron re-acquired tracts 991, 992 and 993 in the 1995 lease sale and made a discovery in 1996 in the Cretaceous, at 15,400 feet. Chevron's plans are not yet announced.

Texaco's January 1986 disappointment in tract 1006 provides further evidence that productive Norphlet with sufficient gas to warrant development is missing in the southern part of the Mobile area OCS, where the Norphlet approaches the shelf edge. The well reached total depth of 23,153.

4.3.9 Major Exploration Achievements/Disappointment: 1985 - 1989

By early 1988, MMS reported discovered reserves at 4 TCF. Operators speculated that discovered reserves at current prices could reach 10 TCF. During 1988 and 1989 four more federal fields were discovered—DD56, 904, 872 and 869—bringing the discovered reserves closer to the 10 TCF estimate.[66] Chevron's Destin Dome discovery and the emerging play on the western trend of the Norphlet stand out as the major exploration achievements of this period. Failure by Conoco, BP, and Texaco to find commercial gas on the southern edge of the Mobile OCS area where Conoco and BP spent over $100 million in Lease Sale 98 stands out as the major disappointment of the five year period. The leases along the southern border of the Mobile OCS have been terminated or allowed to expire.

The March 6, 1989 OGJ contained a graphic of discovered and postulated Norphlet gas structures in the area, which is reproduced as Figure 4.1. While not all of the postulated fields turned out to be commercially productive (e.g., tracts 990/991/999) and not all of the subsequently discovered reservoirs were postulated on the figure (e.g. tracts 904 and 872), Figure 4.1 shows a remarkable number of Norphlet structures with extensive areal coverage.

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[66]OGJ, "Industry slates more exploration development in gulf Norphlet trend," March 6, 1989, p. 15 - 18.

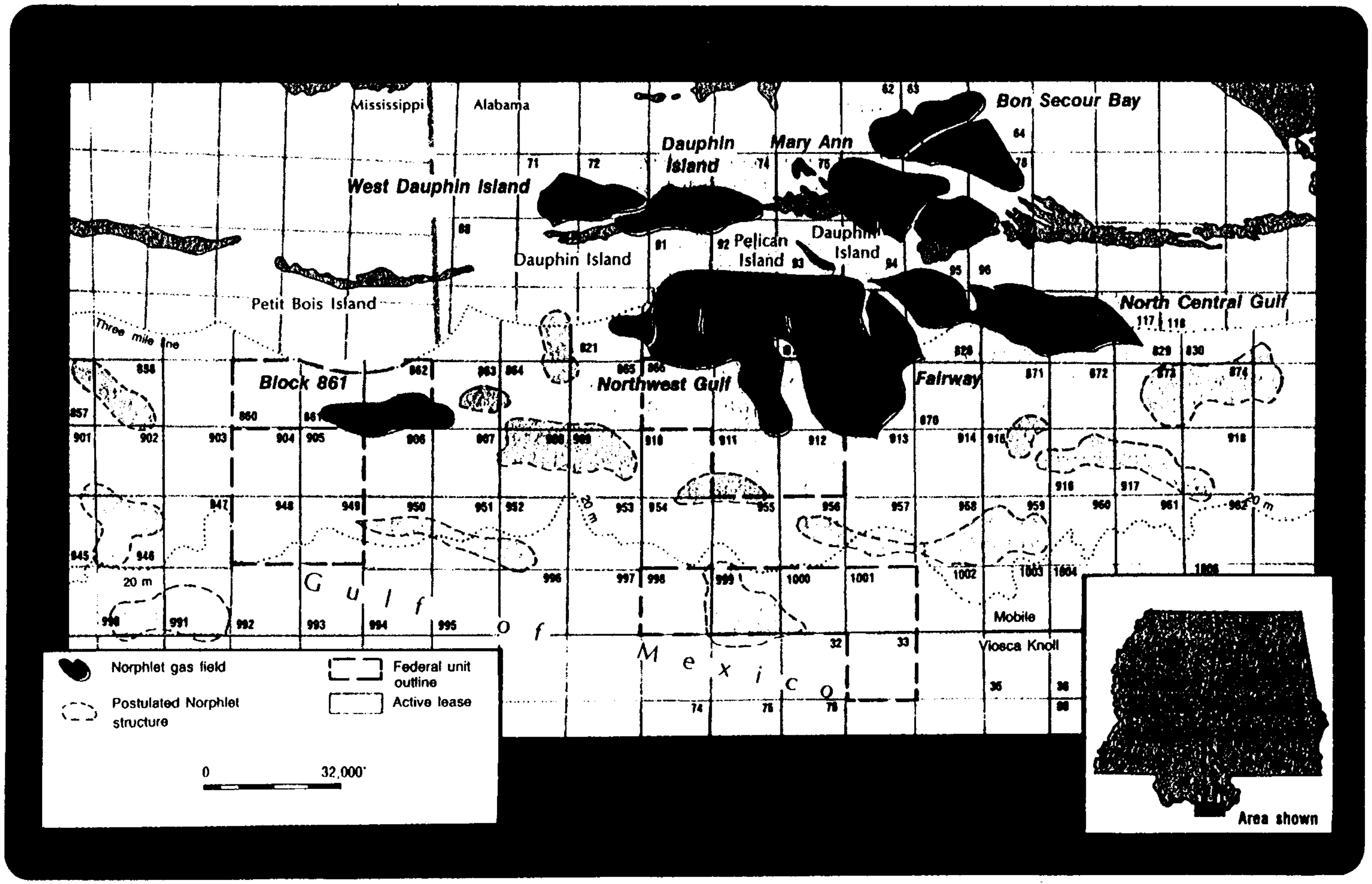

Figure 4.1. Norphlet Structures Off Coastal Alabama.

Source: *Oil and Gas Journal*, March 6, 1989a, p. 15.

Rick Hagar wrote in his summary article that confirmed Norphlet discoveries represented the largest accumulation of U.S. gas found since discovery of Prudhoe Bay.[67]

4.4 Exploration and Development: 1990 to 1993

Eighteen wells were tested between 1990 and June 1993; all but three were development wells. Sixteen of the 18 wells are gas wells, 13 of which are producing in 1997, or are shut-in for workovers. Table 4.5 characterizes the wells as exploration or delineation and shows new field discoveries. Two new fields were discovered during this three and one-half year period: MOEPSI's Aloe Bay Field, north of Dauphin Island, and Union's 916 Field on the eastern edge of the Mobile OCS at the Florida-Alabama line. This brought the total of discovered Norphlet fields to 17. Wells tested in date order are shown on Table 4.6.

Table 4.5
Norphlet Exploration and Delineation Wells Drilled: 1990 - 1993

Operator	Delineation Wells	Exploration Wells	Discovered Fields	Discovery Date
Exxon	114-2, 116-1, 111-1, 112-2, 111-2			
MOEPSI	95-3, 95-4, 823-A3, 823-A4	75-1	Aloe Bay	1/7/92
Shell	113-2,113-3, 113-4			
Chevron	DD56-2, 861-8, 906-2			
Union		950-1, 916-A2	916	12/7/91

Source: Table 4.6.

[67]OGJ, "Industry slates more exploration, development in gulf Norphlet trend," March 6, 1989, p. 15.

Table 4.6
Mobile Bay Norphlet Wells Tested: 1990 - 1993

Tract	Operator	Well	Permit Date	Test Date	Status 12/93	Status 12/97
DD 56	Chevron	DD56-2	10/18/89	11/22/90	Test 22 MMCFD	TA
823	MOEPSI	823-A3	7/7/89	4/25/90	Test 62.3 MMCFD	Producing
823	MOEPSI	823-A4	6/11/90	12/11/90	gas	Producing
95	MOEPSI	95-3	10/16/89	11/15/90	gas	Producing
95	MOEPSI	95-4	11/2/90	5/19/91	gas	TA
950	Union	950-1	2/26/91	8/24/91	P&A	P&A
916	Union	916-A2	3/15/91	12/7/91	Test 42 MMCFD	Producing
861	Chevron	861-8	4/4/91	11/18/91 (TD)	Test 57 MMCFD	Producing
113	Shell	113-2	2/26/90	12/24/91	gas	Producing
113	Shell	113-3	10/19/91	12/25/91	gas	Down for Workover
113	Shell	113-4	10/29/90	1/4/92	gas	Producing
75	MOEPSI	75-1	5/9/91	1/7/92	gas	Producing, Start-up 7/97 at 22 MMCFD
114	Exxon	114-2	1/25/91	2/7/92	gas	Producing
906	Chevron	906-2	11/12/91	5/2/92	P&A	P&A
111	Exxon	111-2	4/4/91	11/24/92	gas	Producing
111	Exxon	111-1	7/6/92	10/29/93	gas	Producing
112	Exxon	112-2	12/13/91	11/4/93	gas	Producing
116	Exxon	116-1	6/26/91	12/1/93	gas	Producing

Source: Alabama Oil and Gas Board, 1997; U.S. Dept. of the Interior, MMS, 1998.

4.4.1 Exxon & Shell Complete Projects and Initiate Production

Exxon and Shell's delineation wells accomplished the following:

- Shell drilled out its Fairway field and started production in December 1991;
- Exxon drilled out its three state fields and started production in October 1993.

The development of these fields is discussed in Section 6.0.

4.4.2 MOEPSI's Development Drilling: Mary Ann and 823

Mobil added two wells to its Mary Ann Field and developed its 823 Field, which started production in November 1991. The development of these fields is discussed in Section 6.0. MOEPSI wells 95-3 and 95-4 completed the drilling program for the original reservoir discovered within its Mary Ann Field. Well 95-3 was tested and brought on production in November 1990. Well 95-3 is the Mary Ann Field's best well, producing an average of 25 MMCFD through September 1996, with lower than field average H_2S, 3.5 percent. Well 95-4 was tested in May 1991, but never produced. After they drilled it, MOEPSI TA'd the well for further evaluation in July 1991. They considered a sidetrack to a better location in 1992. AOGB testimony shows that the well hit "an unusually thick section of tight zone, 163 feet, before penetrating 84 feet of gas."[68] The records show it temporally abandoned.

MOEPSI initiated a program to develop the 823 Field and slated the field for a 1991 start-up. Gas started flowing at 40 MMCFD from a single well in November 1991. Two more wells brought production to 170 MMCFD in March 1992 with less than 200 ppm H_2S.[69] At year end 1993, MOEPSI was producing 140 MMCFD from three wells in 823 to its 250 MMCFD capacity 823 plant. MOEPSI increased its capacity of the Mary Ann Plant to 160 MMCFD to take in the unexpectedly sour gas from 823-A4 well. That well tested 68 MMCFD with 2.8 percent H_2S from 22,570 feet. Production started March 1994.

4.4.3 MOEPSI's Aloe Bay Discovery

Mobil's single exploration well 75-1 discovered its Aloe Bay Field, which covers parts of tracts 74, 75, 92 and 93 on January 7, 1992—underlaying Dauphin Island. Tract 75 was leased from the state in 1988. Gas began flowing to the Mary Ann Plant in July 1997. The plant, which received an average of 144 MMCFD during the first quarter 1997, was debottlenecked to increase capacity to take in the Aloe Bay 8 percent H_2S gas, anticipated to produce between 30 - 50 MMCFD.

[68] AOGB Docket 7-17-964, p. 130.

[69] OGJ, "Gas flowing from field off Alabama," November 11, 1991, p. 27.

4.4.4 Chevron and Union: Eastern and Western Mobile OCS Successes

Chevron, working with Union, continued to drill to delineate their high pressure reservoir[s] underlaying tracts 860, 861, 862, 904, 905, 906, 948, 949, and 950. Chevron's 861-8 reentered the Norphlet at a better location than the 1985 861-1 well, testing 57 MMCFD from 22,103 feet. The well encountered "more than 360 feet of potential pay, suggesting a large gas reservoir."[70]

Union's 950-1 and Chevron's 906-2 were unsuccessful, apparently confirming that the Norphlet structures under 861, 862 and 904 do not trend southeast in sufficient thickness. Well logs show that the wells encountered gas but not in sufficient volume to be economic. They were P&A'd. (See box.)

Norphlet Drilling Challenges

Chevron reported Well 906-2 to have the "best drilling performance yet experienced in the high pressured Norphlet." Central to the completion of the well 32 days ahead of schedule was the selection of drilling bits. "With well depths in Mobile federal waters averaging [over] 22,000 feet, the key criteria for bit selection is to remain on bottom as long as possible in order to avoid costly trips at those depths. . . . Furthermore, the formations encountered in federal Mobile waters are extremely hard and abrasive, particularly the lower Cotton Valley formation between 18,000 - 21,000 feet. . . . High pressure and hard rock, coupled with bottomhole static temperatures exceeding 425°F, will decimate an improperly selected drill bit." In comparison to Chevron's first Norphlet well, 861-1, which used 19 drill bits, 906-2 used only 9, reducing the round trip costs at $2,000 an hour from $483,567 to $291,098. Eight of the nine bits employed on the 906-2 well were metal sealed roller coned bits in contrast to elastomer O-ring seals used in Chevron's 861 and 862 wells. These proved to be inadequate to contend with the aggressive Norphlet drilling environment. The reliability of the metal seals is as critical to successful Norphlet wells as matching the bit choice and operating rate to the formation rock.

Bomar, B., and J. Callais, Offshore/Oilman, January 1993, p. 31 - 33.

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[70]Natural Gas Intelligence, "Chevron, Mobil, Phillips, Apache Announce Large Finds," February 10, 1992, p. 5 - 6.

Chevron achieved confirmation of its discovery on Destin Dome with its DD56-2 well, which tested 22 MMCFD from 22,864 feet November 22, 1990.[71]

Union's 916-A2 well, the first Norphlet discovery in the tract, tested 42 MMCFD December 1991. This was a significant discovery, extending the productive Norphlet trend Chevron discovered with its 872-1 well southeast from Mobile Bay. Union, Chevron and Bechtel's Fremont Energy Corp hold the leases for the tracts that are believed to overlay the discovered reservoir and other productive Norphlet sands—871, 872, 915, 916, 917, 918, 961, and 962.

4.5 Exploration and Development: 1993 - 1997

Drilling in the last five years has been dominated by Chevron and Union developing their eastern and western Mobile Bay Norphlet fields as shown on Table 4.7. Four wells are classified as exploration wells. Murphy's 908-3 well and Chevron's 864-3 well spudded within two months of each other to probe nearby Norphlet targets below 22,000 feet. Well 908-3 was Murphy's first as operator. Chevron hit; Murphy did not. Chevron also drilled a wildcat well in tract 958 that had the same problem found in the 950 and 906 wells: insufficient gas to be economic. Two new fields were discovered in the last four years: Chevron's 864 and 820 fields, bringing the total to 19 Norphlet fields. Eighteen wells tested in date order are shown on Table 4.8, including Exxon's and Chevron's most recent wells spudded, 114-3 and 864-4.

Table 4.7
Norphlet Exploration and Delineation Wells Drilled: 1993 - 1997

Operator	Delineation Wells	Exploration Wells	Discovered Fields	Discovery Date
Chevron	917-2ST, 863-3, 819-1, 820-1, DD57-1, 864-4	958-2 864-3 DD97-1	820 864	12/14/94 6/29/94
Union	904-2, 916-B3, 961-2			
MOEPSI	869-2, 869-3, 95-5ST			
Murphy		908-3,3ST		
Exxon	111-3, 114-3			

Source: Table 4.8.

[71]OGJ, "U.S. Gulf," April 25, 1994, p. 74.

Table 4.8
Mobile Bay Norphlet Wells Spudded and Tested: 1993 - 1997

Tract	Operator	Well	Spud Date	Test Date	Status 12/97
917	Chevron	917-2/A2ST	6/23/93	12/2/93	Producing
916	Union	916-B3	9/24/93	3/15/94	P&A
869	Mobil	868-2	12/18/93	5/18/94	P&A
864	Chevron	864-3	1/28/94	6/29/94	Start up 10/21/96; P&A water problem
DD97	Chevron	DD97-1	3/11/94	7/9/94	P&A
863	Chevron	863-3	12/8/93	9/21/94	Producing; start up 2/19/97 at 18 MMCFD
961	Union	961-2	9/22/94	4/8/95	Producing
908	Murphy	908-3/908-3ST-2	11/23/93	8/27/95	P&A
95	MOEPSI	95-5/95-5ST	4/15/94	10/22/95	Producing; start up 11/96 at 73 MMCFD.
958	Chevron	958-2	11/25/95	2/26/96	P&A
DD57	Chevron	DD57-1	11/7/95	2/7/96	Tested 41 MMCFD; TA
820	Chevron	820-1	9/26/94	12/14/94 (TD);	Producing; 10/31/96 startup at 29 MMCFD
904	Union	904-2	3/15/96	9/18/96	Start-up 12/96 at 32 MMCFD
819	Chevron	819-1	9/17/96	12/15/96 TD	Gas; start-up 1/1/98 at 22 MMCFD
869	MOEPSI	869-3	5/12/96	1/97	Startup at 78 MMCFD
111	Exxon	111-3	3/6/96	3/20/97	Producing; start up at 79 MMCFD
114	Exxon	114-3	3/6/97	10/14/97	gas; start-up Feb, 98 at 65 MMCFD
864	Chevron	864-4	7/13/97	12/97	Producing; start-up at 16 MMCFD

Source: Alabama Oil and Gas Board, 1997; U.S. Dept. of the Interior, MMS, 1998.

4.5.1 Mobil and Exxon Add to Existing Production

Mobil's well, 95-5, came on line during November 1996 producing 66 MMCFD during 20 days of November and 72 MMCFD during December. Well 95-5 is in a reservoir that underlies Exxon's tract 114 tract, the southern portion of Mobil's tracts 94 and 95, and the northwest corner of Exxon's tract 113. (See Box.)

Taking over the lease from Texaco, Mobil drilled well 869-2 which was tested May 18, 1994 at 60 MMCFD. It encountered a liner top problem during completion and was P&A'd. Mobil subsequently spudded 869-3 May 19, 1996, which initiated production in February 1997 at 78 MMCFD; the well produced 85 MMCFD in March, 1997.

Exxon started-up the 111-3 well March 10, 1997 at 79 MMCFD—above expectations—in the Northwest Gulf Field. Exxon's 114-3, an offset to Mobil's 95-5, spudded March 6, 1997 and initiated production in February 1998 at 65 MMCFD.

4.5.2 Murphy's First Norphlet Exploration Venture

Murphy worked for two years trying to find a productive zone as operator of tract 908 which it leased with ARCO and others in 1982. Murphy discovered 400 feet of gas sands but with insufficient permeability, porosity and gas even after several sidetrack attempts over 1994 and 1995. The well was P&A'd August 27, 1995. Murphy's position in the Norphlet remains 33 percent owner of the Destin Dome Unit, plus several yet unexplored Norphlet targets.

4.5.3 Union and Chevron Bring New Fields into Production

Chevron and Union drilled their 916/917 Field with a plan to start production in the first quarter 1995. The 1991 discovery well, 916-A2, was followed by Union's 916-B3 which tested 32.5 MMCFD from 23,026 feet March 1994. The well was reported to penetrate 125 feet of net pay.[72] Chevron's well 917-2ST tested 44 MMCFD in December 1993. Union started production from 916-A2 in April 1995, adding 9 MMCFD from 916-B3 in May.[73] Well 961-A2 initiated production July 31, 1996 at 24 MMCFD. Chevron started-up their 917-2ST well in April 1995 producing 40 MMCFD, 80 ppm H_2S. Well 872-A1 began production February 28, 1996 and averaged 11 MMCFD in mid-year.

Union began production from its 904-1 well on December 22, 1993 at 20 MMCFD. The well reached a peak production rate of 22.3 MMCFD—well below its record test rate—but was lost in August 1994. Chevron started production from 861-8 June 1993 flowing to Union's 904 facility. The well is 120 ppm H_2S. The well initiated production at 30 MMCFD, but developed water problems and was off production from August 1994 until January 1995. It has never produced near the high rates of its initial production, currently maintaining 10 - 12

[72]Dow Jones News, November 21, 1994.

[73]OGJ, "Unocal steps up gas/condensate production," May 29, 1995, p. 24.

3D and CAEX Improved Norphlet Exploration

New exploration technology—3D seismic and computer-aided exploration workstations (CAEX)—has transformed the way companies explore for hydrocarbons and select bottomhole production locations. Although the largest Norphlet reservoirs were discovered before 3D was widespread, MOEPSI's 1995 well 95-5 and its final bottomhole location with a sidetrack 700 feet to the east of the initial location illustrate how 3D and CAEX are improving Norphlet results.

CAEX and 3D are twin technologies using workstations such as Sun or Silicon Graphics, running interpretation software provided by Geoquest, Landmark and others. The companies use this extremely fast computing power to integrate the 3D seismic data with geologic data to interpret the exploration opportunity. 3D seismic processes lines shot at much smaller interline separation than 2D. 2D captures a few lines per mile; 3D processes lines shot at one to two hundred feet and then assembles the data to map the structure in three dimensions. 2D shows less than 25 percent of the subsurface information that 3D shows because 3D processes the closely-spaced information volumetrically. Digicon, a company that performs 3D seismic shoots, uses an NEC SX4 mainframe to process Terabytes of data (1 Terabyte = 1,000 Gigabytes = 1,000,000 Megabytes). With these data intensive tools, geologic structural features appear that cannot be seen with 2D. Fault locations become more certain. Using contrasting color and amplitude extraction, the view of the target zone can be improved to delineate the pay sands. Reservoir areal extent and thickness can be mapped and well path can be designed to penetrate the target at the optimum point.

MOEPSI's well 95-5 illustrates the effects of 3D seismic data on well placement. MOEPSI spudded the 95-5 well in July of 1994, deviated 7400 feet east from a rig located outside the Mobile Bay shipping fairway in tract 94. The initial well was tested May 1995 and judged capable of producing 50 MMCFD. 3D seismic data were used to clarify the top and base of Norphlet and show the geologic depth cross section on the well 95-5. Conventional 2D seismic could be relied upon only to supply information on structural position. The well was sidetracked (ST) to a location 8100 feet east of the rig to maximize both structural height and stratigraphic thickness, reaching total depth in October 1995. (OGB Docket, 7-19-964, p. 123.) Moving the well 700 feet further east from its original bottomhole location improved the porosity from 11.7% to 12.8% and improved productivity of the well markedly. The ST well tested 77.3 MMCFD on October 23 1995. Production averaged 70 MMCFD during December-January, 1997 following start-up in November, 1996.

The improved productivity dramatically helps the economics. The added 20 MMCFD improves cash flow by $20,000 a day, if the wellhead net back price is $1.00 per MCF. An incremental six million dollars a month will pay for a substantial amount of 3D seismic data and drill rig time.

MMCFD. This was the only production to the 904 facilities after 904-1 was lost until Union brought a new well 904-2 on line December 24, 1996 at 32 MMCFD. The well is planned to reach 50 MMCFD after the well has stabilized.[74] The ultimate production rate from the 904 field is yet unknown.

Chevron's well 864-3 started production at 20 MMCFD October 21, 1996, but encountered a water production problem and was shut in. It was P&A'd April 1997. Well 864-4 spudded in July, 1997, to replace 864-3. The well initiated production in December at 20 MMCFD, 40 ppm H_2S; ultimately, the well is expected to produce 35 MMCFD. Chevron's 863-3 well "cut more than 250 feet of net pay below 21,700 feet" in September 1994.[75] Production started February 19, 1997 at 18 MMCFD, ramping up to 47 MMCFD in April 1997. The well tested at an unexpectedly high H_2S content, 1.7 percent. A pipeline was installed to the Shell Fairway Field and the 863-3 gas is processed in the Yellowhammer plant. The well was shut in for repairs in December but was producing 44 MMCFD by April 1998.

Chevron spudded well 819-1 September 1, 1996 which reached total depth of 22,042 December 16, 1996. The drilling time of well 819-1 shows that Norphlet wells are achieving new levels of productivity. The well took 3.5 months, compared to the previous standard of five - six months. Chevron attributed the drilling record to experience gained in bit selection and casing.[76] MOEPSI's first two Norphlet wells took a year. Chevron's well 819-1 initiated production January 1, 1998 at 22 MMCFD.

4.5.4 Chevron's Destin Dome

Having probed the DD56 structure successfully with two wells, Chevron spudded an exploration well on tract 97 in March 1994. This well was unsuccessful. Chevron subsequently hit another gas well in October 1996 on tract DD57—three successes out of four wells—and filed a development plan in December 1996. A May 1, 1996 press release reported a test of 41 MMCFD with average porosity and permeability significantly exceeding the two earlier DD56 wells.

4.5.5 Drilling and Planned Norphlet Wells: 1998

Planned and likely 1998 wells are shown on Table 4.9. Mobil spudded two wells in December, 1997: 823-A5 and 914-4. The 914 well is a partnership with Enron and Chiefton. The latter two companies are partners in the 913/914 leases producing Miocene gas. Nine additional wells are announced or under consideration for drilling in 1998. All of these wells represent extensions of known geology or wells to maintain production.

[74]Union press release, January 9, 1997.

[75]OGJ, "Industry Briefs," October 10, 1994, p. 36.

[76]Personal communication from Gary Jacobs, August 6, 1997.

Table 4.9
Mobile Bay Norphlet Wells Drilling/Planned to Spud: 1998

Tract	Operator	Well	Spud Date	Test Date	Status 12/97
823	Mobil	823-A5	12/97	NA	Drilling
914	Mobil	914-4	12/97	NA	Drilling
61	Mobil	61-1	1998	NA	Planning
75	Mobil	75-2	possible	NA	Planning
821	Shell	821-2	possible	NA	Planning
918	Spirit	918-1	April-May, 1998	NA	Planning
904	Spirit	904-3	After 918-1	NA	Planning
871	Spirit	871-1	possible	NA	Planning
819	Chevron	819-2	possible	NA	Planning
862	Chevron	862-1ST	possible	NA	Planning
863	Chevron	863-4	Sept, 1998	NA	Planning

Source: Industry POEs and telcons with industry staff, 1998.

4.5.6 Norphlet Summary: December, 1997

Through December, 1997, 75 Norphlet wells have been drilled in state and federal waters off Coastal Alabama. The operators shown on Table 4.10 discovered 20 gas fields, all but three of which are producing. MOEPSI abandoned the West Dauphin Island Field as uneconomic; Exxon maintains their 867 Field lease, and plans to produce it in 1998. Chevron and its partners, Conoco and Murphy, have filed a DOCD with MMS to develop Destin Dome. Exxon has drilled the most wells, 20; MOEPSI has drilled 19. Twenty-eight wells were exploration wells. Twenty Norphlet discoveries for 28 exploration wells represents a 71 percent success ratio.

Table 4.11 summarizes production, producing wells and planned wells for the near future, including Destin Dome wells. The fields produced 1.1 BCFD in February 1998 from 40 wells. This table includes wells TA plus the wells that are drilling and planned previously shown on Table 4.9. Nineteen wells are currently TA, drilling or planned including Destin Dome's wells, and Shell's well 113-3 undergoing a workover. These wells will keep the local area busy for the next several years. Potential new production to augment and sustain existing production levels over the next several years will come from:

Two wells initiated production in January and February—819-1 and 114-3;
Two wells spudded in December, 1997—914-4 and 823-A5;

Table 4.10
Mobile Bay State and Federal Norphlet Exploration Summary: 12/97

	Exploration Wells	Delineation Wells	Discovered Fields
MOEPSI	4	15	Mary Ann 823 West Dauphin Island Aloe Bay
Exxon	5	15	Bon Secour Bay 867 Northwest Gulf North Central Gulf 827
Chevron	5	10	861 Destin Dome 820 864 872
Union	4	3	904 916
Shell	2	4	Fairway
BP	2		821
Texaco	3		872 869
Conoco	1		
Placid	1		
Murphy	1		
Total	**28**	**47**	**20 Discovered Fields**

Source: Tables 4.1 - 4.9.

Table 4.11
Active Norphlet Fields - February, 1998

Field Name	Operator (Partners)	Tracts	Discovery Announced	Production Start up	Producing Wells - February Total	Producing Wells - February ID	Drilling/Planned/ Workover/TA Wells Total	Drilling/Planned/ Workover/TA Wells ID	4Q 1997 Production Rate - MMCFD	Processing Plant	Processing Plant Capacity MMCFD
State Offshore											
Mary Ann	MOEPSI	76, 77, 94, 95	11/28/79	4/88	6	76-1, 94-2, 77-1, 77-2/ 95-3/95-5ST	1	95-4-TA	105	Mary Ann/Yelham/823	180
Bon Secour Bay	Exxon	62, 63, 64 , 78	03/14/84	11/93	3	62-1, 63-1, 78-1	1	61-1-P	106	Exxon	400
Northwest Gulf	Exxon	111, 112, 131	12/25/84	10/93	5	111-1, 111-2, 111-3, 112-1, 112-2	0		201	Exxon	
North Central Gulf	Exxon	114, 115, 116	04/12/85	11/93	4	115-1, 114-2, 116-1, 114-3	0		125	Exxon	
Fairway	Shell/Amoco	113, 132	05/02/86	12/91	4	113-1, 2, , 4, 132-1	1	113-3-WO	98	Yellowhammer	200
Aloe Bay	MOEPSI	74, 75, 92, 93	01/07/92	7/97	1	75-1	1	75-2-P	23	Mary Ann	
Subtotal	*6*				*23*		*4*		*658*		*780*
Federal OCS											
823 Field	MOEPSI	822, 823, 824	02/24/84	11/91	4	823-A1, 2, 3/A4	1	823-5-D	139	823/Mary Ann	300
867 Field	Exxon	867, 868, 911	07/26/84	1998	0		1	867-1-TA	0	Exxon	
861 Field	Chevron	860, 861, 862	08/12/85	12/93	1	861-8	1	862-1ST	9	904 Platform	80
821 Field/109 state	Shell	821	04/10/86	11/92	1	821-1	1	821-2-P	15	821 Platform	60
827 Field	Exxon	827, 828	04/21/86	11/93	1	827-1	0		29	Exxon	
Destin Dome	Chevron/ Conoco/		01/07/88	2000	0		5		0	Destin Dome	NA
904 Field	Union	904, 905, 948, 949	05/18/88	12/93	1	904-2	1	904-3-P	38	904 Platform	
872 Field	Chevron	872, 873	07/24/88	4/95	1	872-A1	0		12	916 Platform	150
869 Field	MOEPSI/Exxon	868, 869, 914	08/22/89	1/97	1	869-3	1	914-4-D	64	823 Plant	
916 Field	Union/Chevron	871, 915, 916, 917, 918, 961, 962	12/07/91	4/95	3	916-A2, 961-A2, 917-A2ST	2	918-1, 871-1-P	62	916 Platform	
820 Field	Chevron	819, 820	12/16/96	10/96	2	820-1, 819-1	1	819-2-P	55	864 Platform	150
864 Field	Chevron	863, 864	09/21/94	2/97	2	863-3/ 864-4	1	863-4-P	65	Yellowhammer/864	
Subtotal	*13*				*17*		*15*		*488*		*740*
Total	**19**				**40**		**19**		**1146**		**1520**

Source: Foster Associates, Inc. , April, 1998.

notes: Exxon 867-1 has to be put online by 12/31/98 or lose the lease. Mobil has to drill tract 61 by 12/31/98 or lose the lease.

Chevron's 863-3 well was down to repair a safety value during 4Q; production rates shown are Apri 1998 production plus new well 864-4, which started in December and is producing 16 MMCFD.

Chevron 819-1 started production January 1 at 22 MMCFD.

Exxon 114-3 started production early February at 65 MMCFD.

Three wells TA, pending further evaluations—95-4, 867-1 and 862-1, which will be sidetracked in 1998;
One well down for workover—113-3;
Eight wells under consideration in 1998 for drilling shown on Table 4.9;
Five wells planned for Destin Dome.

Table 4.12 shows the number of Coastal Alabama and Destin Dome Norphlet wells tested by year. Four to six wells have been tested annually in every year of the 1990s, averaging 4.5 wells tested per year. Drilling and planned wells will maintain that average at least until Destin Dome comes into production.

Good thing MOEPSI decided to drill a mile below the Smackover to the Norphlet in their original exploration of Lower Mobile Bay!

Table 4.12
Norphlet Wells Tested by Year

Year	No. of Norphlet Wells	Year	No. of Norphlet Wells
1979	1	1988	6
1980	0	1989	3
1981	0	1990	4
1982	2	1991	6
1983	4	1992	5
1984	5	1993	4
1985	8	1994	6
1986	7	1995	3
1987	3	1996	4
		1997	4

4.6 Miocene Exploration, Development and Transportation in Coastal Alabama State and Federal Waters

MOEPSI tested the first offshore Miocene well in 1982 as part of the Lower Mobile Bay development plan. Well 95-2 tested 4 MMCFD October 9, 1982; the gas was used as fuel gas for the project and the well is now shut-in. While majors have focused mainly on finding and developing Norphlet gas, several independents have pursued smaller, shallow Miocene gas prospects in Coastal Alabama state and federal waters. ODECO President Hugh Kelly called the Alabama Miocene "an independent's play," in a 1989 OGJ article. Miocene wells are drilled in a few days to a few weeks for little more than $150,000 and discoveries average 10 - 15 BCF[77] versus numbers ranging in the hundreds of BCFs for Norphlet discoveries.

The critical achievement of the Miocene development was the Dauphin Island Gathering System (DIGS) pipeline, constructed to transport the gas to market. This is discussed within this section.

4.6.1 Miocene Geology Overview and Drilling Summary

The Miocene is a much younger geologic age formation found between 1,500 - 3,000 feet in the state offshore region dipping to 4,000 - 7,500 feet in the federal OCS.[78] Miocene gas is typically 99.9 percent methane, probably biogenic in origin, in comparison to Norphlet comprised of substantial H_2S and CO_2 contaminants. Miocene gas is pipeline quality requiring none of the specialized technology processes used with Norphlet gas. Bottomhole pressures for Miocene discoveries range from 550 to 1,200 psi compared to >10,000 psi for Norphlet.

The Miocene sands are categorized as upper, middle and lower, with the strata dipping down to the southwest from Mobile Bay. Gas-bearing Miocene sands have been discovered throughout Southwest Alabama, but discoveries have been generally deeper, larger, more numerous and more productive offshore. Union Exploration vice-president, Graydon H. Laughbaum was quoted as saying "MOEPSI's discovery in the Mary Ann Field led his company to the trend. . . . Everyone knew the Miocene was there; but we didn't map it in detail until we got better [3D] seismic and decided it was worth drilling for on its own."[79]

Table 4.13 shows the Miocene wells drilled in date order in state and federal waters. Following MOEPSI's state Miocene well 95-2, Tenneco tested the next Miocene well on OCS block 864 in January 1983 (now operated by Chevron). A total of 40 Miocene wells were drilled in the Mobile OCS between 1983 and 1989, 76 total in state and federal waters through 1996. Besides the obvious objective of discovering economic gas reservoirs, the wells were drilled to achieve two other purposes:

- Search for sufficient discovered reserves to justify a pipeline system;

- Demonstrate activity on the leases sufficient to meet the five year lease requirement.

The peak drilling years, 1985 and 1987, when 10 and 13 Miocene wells were drilled, are coincident with the second bullet objective. Over two-dozen of these wells tested gas for a success rate of 64 percent. Only two miocene wells were drilled in 1996. Table 4.14 shows

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[77]OGJ, "Smaller Miocene targets draw attention in Norphlet areas," March 6 1989, p. 17.

[78]Petroleum geology draws from Mink, Robert M., Ernest A. Mancini, Bennett L. Bearden and Charles C. Smith, "Middle and Upper Miocene Natural Gas Sands in Onshore and Offshore Alabama," AOGB Reprint Series 71, 1988.

[79]OGJ, "Smaller Miocene targets draw attention in Norphlet areas," March 6 1989, p. 17.

Table 4.13
Mobile Bay Miocene Wells Spudded: 1979 - 1997

Field	Tract	Current Operator	Well Number	Well Depth	Date Tested, TA or Plugged	Well Status	No. of Wells Per Year
N. Dauphin Is	95	MOEPSI	2	3,058	10/09/82	SI	1
864	864 M	Chevron	1	3,050	01/09/83	P&A	1
952	953 M	Murphy	1	3,620	03/20/84	COM	
955	955 M	Murphy	1	4,119	04/14/84	P&A	2
952	952 M	Murphy	1	4,270	03/04/85	COM	
861	908 M	ARCO	1	3,145	04/15/85	P&A	
864	861 M	Chevron	2	4,375	04/18/85	Gas/COM	
864	863 M	Chevron	1	3,050	04/22/85	TA	
861	861 M	Chevron	4	3,650	05/12/85	Gas/COM	
861	861 M	Chevron	5	3,650	05/15/85	Gas/COM	
861	861 M	Chevron	7	3,650	06/16/85	Gas/COM	
861	861 M	Chevron	6	12,333	08/06/85	Gas	
861	861 M	Chevron	3	11,352	08/06/85	Gas/DSI	
864	908 M	Chevron	2	4,094	08/17/85	Gas	10
914	914 M	Enron	A1	2,906	07/12/86	COM	
906	906 M	Chevron	1	3,700	07/31/86	P&A	
991	991 M	Conoco	1	4,960	10/15/86	P&A	3
870	870 M	Santa Fe	1	2,449	02/25/87	COM	
870	870 M	Santa Fe	A1	2,449	03/09/87	COM	
955	955 M	Murphy	2	4,080	07/27/87	COM	
959	959 M	VASTAR	1	3,100	10/09/87	ST	
959	959 M	VASTAR	1	2,078	10/17/87	P&A	
960	960 M	VASTAR	1	3,100	10/25/87	TA	
870	870 M	Santa Fe	2	2,292	11/02/87	COM	
916	916 M	Union	1	3,100	11/15/87	TA	
914	914 M	Enron	A2	2,456	11/15/87	COM	
914	914 M	Enron	3	2,489	11/25/87	COM	
914	958 M	Chevron	1	2,601	11/30/87	P&A	
870	870 M	Santa Fe	3	2,550	12/09/87	P&A	
961	961 M	Union	1	3,191	12/16/87	COM	13
959	915 M	Union	1	2,378	01/07/88	COM	
961	917 M	Union	1	3,068	05/11/88	P&A	
864	864 M	Chevron	A2	3,197	08/06/88	COM	
1003	1003 M	Union	1	2,800	11/22/88	P&A	
1002	1002 M	Union	1	3,500	12/01/88	P&A	5
881	881 P	Apache	1	2,700	01/28/89	TA	
830	830 M	Apache Corp.	1	2,050	02/18/89	TA	
	873 M	Texaco	1	2,410	02/26/89	P&A	
865	865 M	Scana	1	3,800	05/19/89	TA	
	873 M	Gulfstar	2	1,850	06/22/89	P&A	
SE Mobile Bay	77	MOEPSI	4	3,075	08/08/89	P&A	6
947	947 M	Hall-Houston	1	3,200	05/09/90	COM	
990	990 M	Hall-Houston	1	4,033	05/26/90	COM	
945	945 M	Hall-Houston	1	4,400	06/04/90	COM	
N. Dauphin Is	73	Callon	1	2,510	07/09/90	Gas	
NW Dauphin Is	71	OGI	1	2,514	07/21/90	Gas	
N. Dauphin Is	72	Callon	2A	2,252	07/31/90	Gas	
864	863 M	Chevron	2	3,400	08/07/90	COM	
864	907 M	Chevron	A1	2,800	08/07/90	COM	8
N. Dauphin Is	73	Callon	1	3,977	06/09/91	Gas	
N. Dauphin Is	73	Callon	2	3,644	07/02/91	Gas	
N. Dauphin Is	73	Callon	3	3,978	07/27/91	Gas	
WC	71	ARCO	1	4,334	08/23/91	P&A	4
S. Dauphin Is.	91	OEDC	1	3,464	04/09/93	Gas	
823	822 M	OEDC	A1	2,707	05/17/93	COM	
823	822 M	OEDC	A2	3,085	05/24/93	COM	
S. Dauphin Is.	90	OEDC	2	3,842	06/11/93	Gas	
S. Dauphin Is.	90	OEDC	1	2,460	06/11/93	Gas	
NE Petit Bois Pass	71	OGI	1	2,100	10/11/93	Gas	5
NW Dauphin Is	57	OGI	1	1,938	01/16/94	Gas	
S. Dauphin Is.	90	OEDC	1 ST	3,779	04/05/94	Gas	
865	865 M	Scana	A2 ST	1,721	04/22/94	COM	
866	822 M	OEDC	5	1,400	06/12/94	P&A	
866	822 M	OEDC	B1	1,677	07/19/94	COM	
959	959 M	OEDC	A1	2,310	10/16/94	COM	
959	959 M	OEDC	A2	2,610	11/09/94	COM	
960	960 M	OEDC	A1	2,279	11/20/94	ST	8
959	959 M	OEDC	A3	2,567	01/19/95	ST	
865	865 M	Scana	A3	2,502	01/23/95	COM	
E. Miss. Sound	59	Legacy	1	5,100	02/25/95	Gas	
959	959 M	OEDC	A3	2,396	03/25/95	COM	
Goose Bayou	59(SL)	8 Legacy	1–2	5,414	04/10/95	Gas	
960	960 M	OEDC	A2	2,313	04/17/95	COM	
959	959 M	OEDC	A4	2,076	05/28/95	COM	
NE Petit Bois Pass	71	OGI	1	3,204	11/16/95	Gas	
960	960 M	OEDC	A1 ST	2,290	11/25/95	COM	9
NW Dauphin Is	71	OGI	3 2 ST	3,995	02/13/96	Gas	
861	861 M	Chevron	9	3,385	10/23/96	COM	2

Source: Alabama Oil and Gas Board, 1986; U.S. Dept. of the Interior, Minerals Management Service, 1998.

Table 4.14
Mobile Bay Miocene Gas Wells

Field	Tract	Current Operator	Well Number	Well Depth	Date Tested, TA or Plugged	Well Status
E. Miss. Sound	59	Legacy	1	5,100	02/25/95	Gas
Goose Bayou	59(SL)	Legacy	1-2	5,414	04/10/95	Gas
NE Petit Bois Pass	71	OGI	1	2,100	10/11/93	Gas
NE Petit Bois Pass	71	OGI	1	3,204	11/16/95	Gas
NW Dauphin Is	71	OGI	3 2 ST	3,995	02/13/96	Gas
NW Dauphin Is	71	OGI	1	2,514	07/21/90	Gas
NW Dauphin Is	57	OGI	1	1,938	01/16/94	Gas
N. Dauphin Is	73	Callon	1	2,510	07/09/90	Gas
N. Dauphin Is	73	Callon	3	3,978	07/27/91	Gas
N. Dauphin Is	72	Callon	2A	2,252	07/31/90	Gas
N. Dauphin Is	73	Callon	1	3,977	06/09/91	Gas
N. Dauphin Is	73	Callon	2	3,644	07/02/91	Gas
N. Dauphin Is	95	MOEPSI	2	3,058	10/09/82	SI
S. Dauphin Is.	91	OEDC	1	3,464	04/09/93	Gas
S. Dauphin Is.	90	OEDC	2	3,842	06/11/93	Gas
S. Dauphin Is.	90	OEDC	1	2,460	06/11/93	Gas
S. Dauphin Is.	90	OEDC	1 ST	3,779	04/05/94	Gas
823	822 M	OEDC	A1	2,707	05/17/93	COM
823	822 M	OEDC	A2	3,085	05/24/93	COM
830	830 M	Apache Corp.	1	2,050	02/18/89	TA
861	861 M	Chevron	9	3,385	10/23/96	COM
861	861 M	Chevron	3	11,352	08/06/85	Gas/DSI
861	861 M	Chevron	7	3,650	06/16/85	Gas/COM
861	861 M	Chevron	4	3,650	05/12/85	Gas/COM
861	861 M	Chevron	5	3,650	05/15/85	Gas/COM
861	861 M	Chevron	6	12,333	08/06/85	Gas
864	863 M	Chevron	1	3,050	04/22/85	TA
864	907 M	Chevron	A1	2,800	08/07/90	COM
864	908 M	Chevron	2	4,094	08/17/85	Gas
864	863 M	Chevron	2	3,400	08/07/90	COM
864	861 M	Chevron	2	4,375	04/18/85	Gas/COM
864	864 M	Chevron	A2	3,197	08/06/88	COM
865	865 M	Scana	1	3,800	05/19/89	TA
865	865 M	Scana	A3	2,502	01/23/95	COM
865	865 M	Scana	A2 ST	1,721	04/22/94	COM
866	822 M	OEDC	B1	1,677	07/19/94	COM
870	870 M	Santa Fe	2	2,292	11/02/87	COM
870	870 M	Santa Fe	1	2,449	02/25/87	COM
870	870 M	Santa Fe	A1	2,449	03/09/87	COM
881	881 P	Apache	1	2,700	01/28/89	TA
914	914 M	Enron	A2	2,456	11/15/87	COM
914	914 M	Enron	A1	2,906	07/12/86	COM
914	914 M	Enron	3	2,489	11/25/87	COM
916	916 M	Union	1	3,100	11/15/87	TA
945	945 M	Hall-Houston	1	4,400	06/04/90	COM
947	947 M	Hall-Houston	1	3,200	05/09/90	COM
952	952 M	Murphy	1	4,270	03/04/85	COM
952	953 M	Murphy	1	3,620	03/20/84	COM
955	955 M	Murphy	2	4,080	07/27/87	COM
959	915 M	Union	1	2,378	01/07/88	COM
959	959 M	OEDC	A3	2,567	01/19/95	ST
959	959 M	OEDC	A3	2,396	03/25/95	COM
959	959 M	OEDC	A4	2,076	05/28/95	COM
959	959 M	OEDC	A2	2,610	11/09/94	COM
959	959 M	OEDC	A1	2,310	10/16/94	COM
959	959 M	VASTAR	1	3,100	10/09/87	ST
960	960 M	OEDC	A2	2,313	04/17/95	COM
960	960 M	OEDC	A1	2,279	11/20/94	ST
960	960 M	OEDC	A1 ST	2,290	11/25/95	COM
960	960 M	VASTAR	1	3,100	10/25/87	TA
961	961 M	Union	1	3,191	12/16/87	COM
990	990 M	Hall-Houston	1	4,033	05/26/90	COM

Source: Alabama Oil and Gas Board, 1986; U.S. Dept. of the Interior, Minerals Management Service. 1998.

the gas wells re-ordered by subsequently defined fields. A substantial number of small Miocene reservoirs were discovered before a pipeline was built to bring the gas to market.

4.6.2 Dauphin Island Gathering System

Central to Miocene development was Offshore Energy Development Corp (OEDC) development of the Dauphin Island Gathering System (DIGS) to move gas to shore. OEDC drilled its first Miocene gas discovery June 1991 on Alabama tract 90, followed by a subsequent discovery on tract 91. OEDC conceived the need for a pipeline to transport its own and other's gas to shore. OEDC's strategy was to develop a gathering system through Coastal Alabama to pick up both miocene and pipeline quality Norphlet gas (e. g., Norphlet gas from BP and Union/Chevron processed on the platforms).

Rather than skirt Dauphin Island via the ship channel at the mouth of Mobile Bay, OEDC decided DIGS could be routed by boring under Dauphin Island and heading straight to the Interstate connection. Permits and right-of-way were approved in the fall of 1991 and OEDC started looking for partners to pay for the project. BP was planning to start its 821-1 in January 1992 and agreed to dedicate its Block 821 gas to DIGS. OEDC obtained commitments from Miocene producers south and north of Dauphin Island in addition to BP and the first stage of DIGS was completed before the end of 1991.[80]

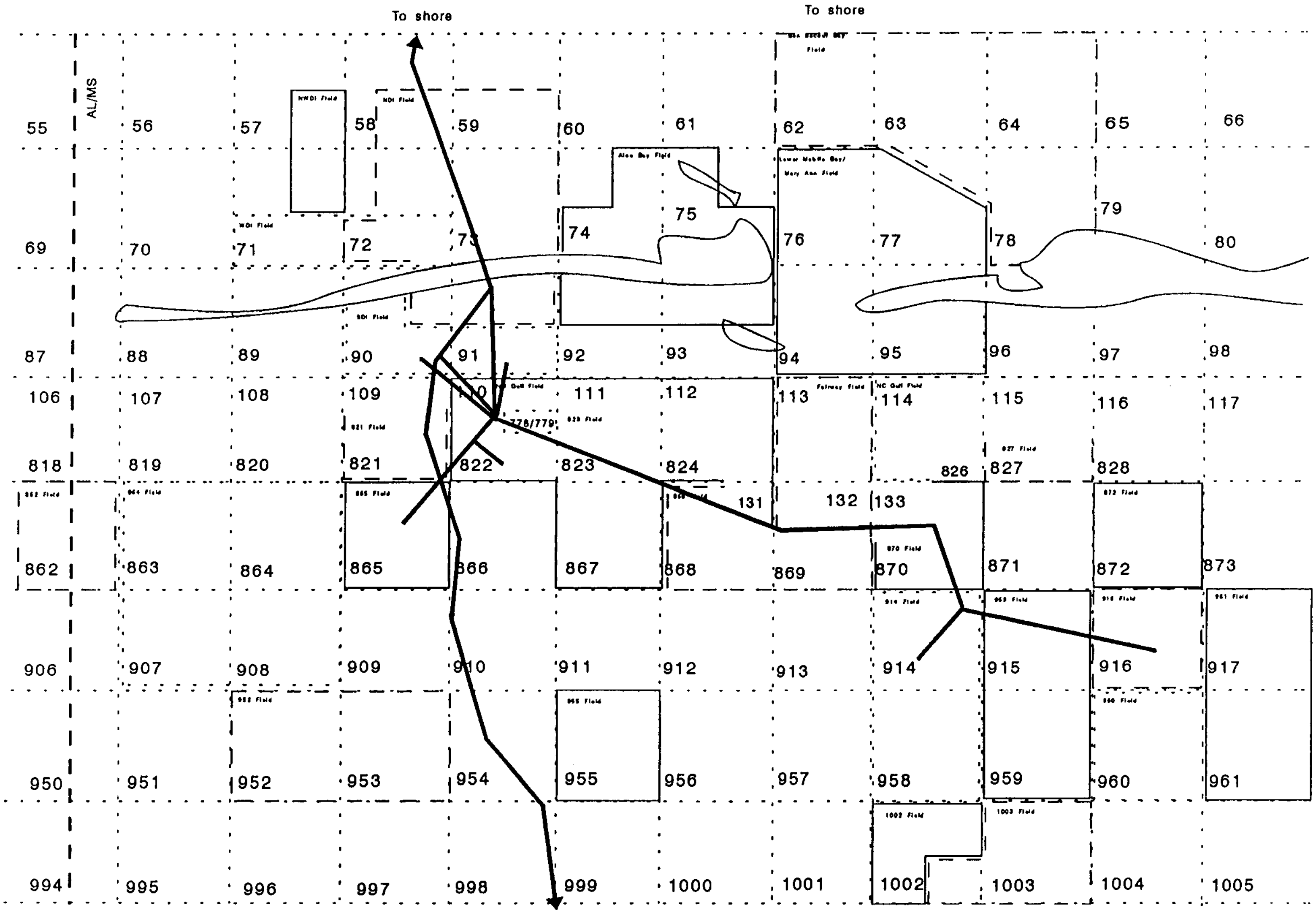
DIGS begins on Block 822, where a number of gathering pipelines from nearby fields converge at OEDC's central gathering facility. BP's 12-inch pipeline connects to the Block 822 platform, which in turn connects to the DIGS just south of Dauphin Island. OEDC bored an almost mile-long tunnel through Dauphin Island and ran three 12-inch pipes through the island—one for immediate capacity, and two for expansion. Figure 4.2 shows the location of DIGS in relation to other existing pipelines in Mobile Bay.

Gas emerges from the northern shore of Dauphin Island, flowing through the 20-inch DIGP pipeline (a partnership between Enron and OEDC) that travels onshore to OEDC's metering station and the Transco and Koch Interstate pipeline systems. On its way to shore, the 20-inch DIGP pipeline travels through the North Dauphin Island Field, where it connects with gathering lines from platforms in state blocks 71, 72, and 73.

OEDC expanded the pipeline from its 822 platform through federal waters to the east to connect platforms in Mobile Blocks 870, 914, 915, and 916. In January of 1994, OEDC installed 20-inch pipe for a 40-mile extension from BP's Mobile 821 platform south across federal waters to Block 954 in the southern Mobile area and still further south into the Viosca Knoll OCS area. This pipeline began transporting gas to market in late 1994.[81]

[80]OEDC Prospectus October 9, 1996, p. 40.

[81]OGJ, "Mobile Bay gas flow rising in response to E&D campaigns," January 10, 1994, p. 23.



DIGS

Figure 4.2. Dauphin Island Gathering System.

Source: Foster Associates, 1997.

DIGS current capacity is 400 MMCFD but construction during 1997 increased the DIGP connector capacity from Dauphin Island to the onshore terminus to 450-550 MMCFD, and extend the pipeline south to provide gathering services in Viosca Knoll and Main Pass East Addition areas. The DIGS extension will provide the first northern outlet for gas from the East Central Gulf Area to East Coast Markets. A substantial quantity of gas from the deep water development in the vicinity of Main Pass block 225 will move north over this pipeline by winter 1998. OEDC and partners will operate a NGL plant at the terminus to strip the NGLs from the deep water gas south of Mobile Bay.

4.6.3 Chandeleur Connection

The fields in the western portion of the Mobile OCS are connected to the Mobile Area Gathering System (MAGS), which connects to either the Chandeleur pipeline of Pascagoula, or to Callon's Interstate connector in Mobile County. Chandeleur is a pair of pipelines (one 16-inch and one 12-inch) that extend from the Mississippi shore through the western edge of the Mobile OCS and further south into the Chandeleur OCS. ODECO owns a six-inch gathering system that connects Mobile 955, 954, 953, and 952 to Chevron's "A" platform in Mobile 908. Gathering lines connect Chevron's Mobile 908 "A" platform to wells in Mobile 863 and 908. From Chevron's Mobile 908 "A" platform, gas flows through a 12-inch line to Mobile 861, where it enters a 12-inch spur owned by Chandeleur, travels through Mobile 904, and connects with the Chandeleur pipeline system. Chevron constructed a 12-inch pipeline to connect its Mobil 861 platform with the Chandeleur pipeline system in mid-1995.

4.6.4 Production Start-Up: Miocene

ARCO came on-line with the first Miocene wells producing for the commercial market and became the second producer in Coastal Alabama, following MOEPSI. After drilling three gas wells in 1990 in tracts 71, 72 and 73, ARCO moved to immediately develop their discovery. Like the Norphlet developments, the environmental sensitivity of the Dauphin Island setting was a critical consideration. Ultimately, ARCO applied several innovative technologies to bring the North Dauphin Island and Northwest Dauphin Island Fields into production. Horizontal drilling, not typically used for shallow wells, was used to reduce the number of wells. Pipelines under shorelines were bored to reduce the impacts to wetlands and oyster beds. A special platform design was used to prevent rainwater from coming into contact with the main deck of the platform and then running-off into the Mississippi Sound. Zero discharge was expected of Miocene producers as well as Norphlet producers. Platforms were painted blue and gray to blend into the seascape and lighting was shielded to minimize the visual pollution to near-by onshore vacation homes.[82]

ARCO initiated production in the North Dauphin Island Field (NDI) in December 1991 and in the Northwest Dauphin Island (NWDI) Field in March 1992. ARCO subsequently sold its leases and discovered reserves to Callon and Offshore Group in mid-1993. Table 4.15 summarizes the

[82]R. P. Layfield, K. L. Elser, and R. H. Ostler, "Dauphin Island Natural Gas Project," JPT, January, 1994, p. 63 - 66.

Table 4.15
Summary of Mobile Bay State and Federal Miocene Production (BCF)

Field	Current Operator	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Cumulative Thru 1997
State												
East Mississippi Sound	Legacy	-	-	-	-	-	-	-	0.1	1.8	0.1	2.0
Goose Bayou	Legacy	-	-	-	-	-	-	-	0.1	1.3	0.1	1.5
North Dauphin Island	Callon	-	-	-	0.2	19.3	15.9	11.1	7.4	3.8	2.1	59.8
Northeast Petit Bois Pass	Offshore Group	-	-	-	-	-	-	0.4	0.1	1.2	0.5	2.1
Northwest Dauphin Islan	Offshore Group	-	-	-	-	0.6	0.9	2.0	1.2	0.9	0.6	6.2
South Dauphin Island	SCANA	-	-	-	-	-	0.6	3.5	2.6	1.5	0.7	8.9
Southeast Mobile Bay	MOEPSI	0.2	0.1	-	-	-	-	-	-	-	-	0.3
Subtotal State		0.2	0.1	-	0.2	19.9	17.4	17.0	11.5	10.5	4.1	**80.9**
Federal												
Mobile 823	Scana	-	-	-	-	-	2.3	6.8	5.2	3.2	2.1	19.5
Mobile 861	Chevron USA	-	-	-	-	-	-	-	-	0.0	2.0	2.0
Mobile 864	Chevron USA	-	-	-	-	18.8	20.5	18.2	13.8	11.5	8.7	91.5
Mobile 865	Scana	-	-	-	-	-	-	2.9	3.4	2.8	1.5	10.6
Mobile 866	Scana	-	-	-	-	-	-	0.9	0.9	1.0	0.6	3.4
Mobile 870	Enron	-	-	-	-	-	-	1.1	4.7	5.3	5.6	16.7
Mobile 914	Enron	-	-	-	-	-	-	1.0	2.5	1.5	0.7	5.6
Mobile 945	Apache	-	-	-	0.1	1.1	0.8	0.6	0.5	0.2	0.1	3.5
Mobile 947	Apache	-	-	-	0.1	1.9	1.6	1.0	1.1	0.9	0.6	7.3
Mobile 952	Murphy	-	-	-	-	0.8	1.1	1.0	1.0	1.3	3.4	8.6
Mobile 955	Murphy	-	-	-	-	1.0	1.4	1.2	1.1	1.0	0.9	6.7
Mobile 959	OEDC/Unocal	-	-	-	-	-	-	-	4.9	3.1	1.4	9.5
Mobile 959	OEDC	-	-	-	-	-	-	-	0.9	0.6	0.4	1.9
Mobile 961	Unocal	-	-	-	-	-	-	-	1.4	1.3	0.8	3.5
Mobile 990	Apache/Enron	-	-	-	0.4	4.3	3.9	2.9	2.5	1.8	1.2	16.9
Subtotal Federal		-	-	-	0.6	27.9	31.7	37.5	44.0	35.4	30.0	**207.1**
Total Miocene Production		**0.2**	**0.1**	-	**0.8**	**47.8**	**49.0**	**54.5**	**55.5**	**45.9**	**34.1**	**288.0**

Source: AL Oil and Gas Board, 1997; Dwights/PI, 1997; US DOI MMS, 1998.

production from fields by current operators. ARCO's production from the North Dauphin Island Field averaged 53 MMCFD in 1992 while the Northwest Dauphin Island Field produced less than 2 MMCFD. The NDI production rate and the amount of gas produced through year end 1996 is uncharacteristically high for a Miocene structure. No other State of Alabama Miocene field has produced such a quantity of gas, or produced at such a high rate.

Inspection of Table 4.15 shows another Miocene field in the OCS with comparably high and sustained production. Miocene 864 Field hit 56 MMCFD in 1993 and has produced 83 BCF at year end 1996. Chevron's tract 864 is immediately contiguous to Murphy's tract 908 which was an unsuccessful Norphlet play. The unusually high and sustained Miocene production rate from tract 864 may be the gas missing from the "very good" Norphlet sands Murphy probed with 908-2 and two sidetracks.[83] If so, not all Coastal Alabama Miocene gas is necessarily biogenic in origin. If the high production from 864 and NDI may be Norphlet in origin, the distinctive H_2S signature present in all other Norphlet gas is missing. Wellstream analysis of the state NDI wells shows that they are 98 - 99 percent methane, with Nitrogen being the second largest component.

Production stepped-up annually through 1995 from Coastal Alabama Miocene fields after DIGS was in place. Figure 4.3 shows the production through 1997 from the state and federal Miocene fields. Production from the producing Miocene reservoirs appears to be in decline. Table 4.15 shows that through year end 1997 Miocene production totalled 288 BCF.

[83]Telcon with Murphy exploration manager, May 16, 1997.

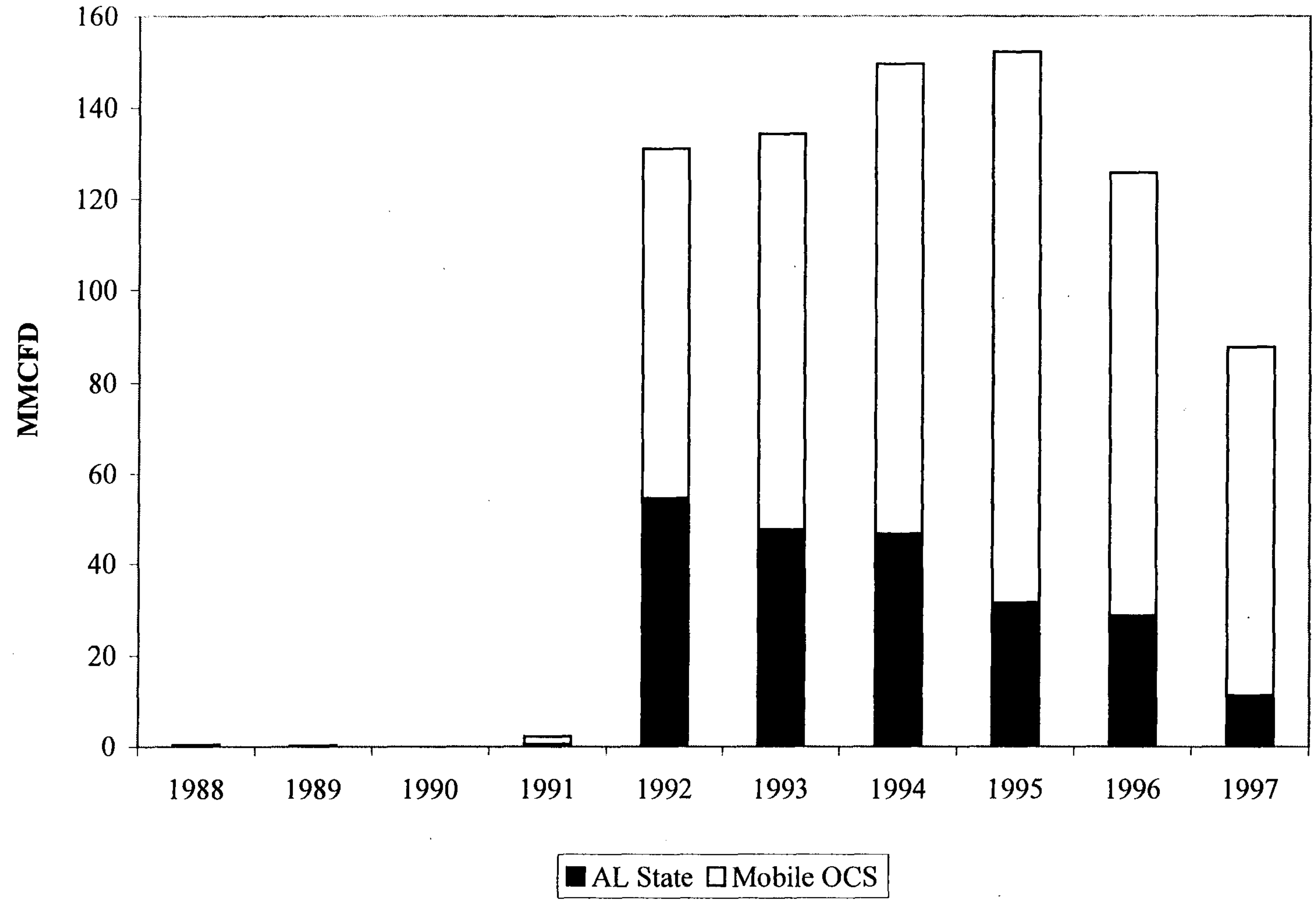


Figure 4.3. Summary of Mobile Bay State and Federal Miocene Production.

Source: AL Oil & Gas Board; Dwights/PI; MMS, 1998

5.0 State Field Definitions from AOGB Dockets[81]

Companies file substantial information with the AOGB as required by State of Alabama regulations. The following subsections report selected information about their reservoirs submitted by Exxon, MOEPSI and Shell. The purpose of the section is to show how the predominantly northwest-southeast trending eolian sandstone Norphlet reservoirs appear and how faults define the areal extent of the reservoirs. Similar information for federal fields is not available.

5.1 Exxon Bon Secour Bay Field

Exxon's Bon Secour Bay was named and defined by AOGB Order 85-345 in Docket 12-19-85. Tracts 62, 63 and 64 were originally included in the field. This was amended to include tract 78 and the northeast corner of tract 77 on April 15, 1992. Mr. Jeff Durrant appeared for Exxon with attorney Tom Watson to revise the field limit as shown on Figure 5.1; i.e., to incorporate the segment of tract 77 northeast of the fault shown on Figure 5.2, 1306 acres in total that do not contain Mobil's Mary Ann reservoir, and do contain the Bon Secour Bay reservoir. Mr. Durrant testified that four wells had been drilled into the reservoir from each of Exxon's tracts. Exxon's well locations can be seen on Figure 5.1. Mobil's eight existing 1992 Mary Ann Field wells are also shown. Figure 5.2 shows that the wells in tracts 63 and 78 are on either side of the top of the reservoir structure, which follows the fault that runs northwest to southeast from tract 63 to 78. The fault, which is also visible on MOEPSI's exhibits, seals the Mary Ann Field and separates it from the Bon Secour Bay Field. Exxon testified that "the most orderly and efficient development of the . . . revised formation will avoid the drilling of unnecessary wells, . . . prevent waste, and . . . protect the coequal and correlative rights of all unit owners."[82]

Two east-west trending faulted salt anticlines, which are the traps for natural gas in the field, can be seen on Figure 5.2. Average net pay in the field is 136 feet. Reservoir sandstones are interpreted as eolian. Porosity averages 12 percent and permeability varies from <0.01 to up to 44.6 md. While truncated on the west border of Exxon's tract, the reservoir can be inferred to extend west to tract 61, which Mobil leased in 1993 for $1.5 million in bonus payment.

5.2 Exxon North Central Gulf Field

Exxon's North Central Gulf Field was named and defined by AOGB Order 86-239 in Docket 9-5-86. Tracts 114, 115, 116, and 117 were included in the field. Witnesses appearing for Exxon with attorney Tom Watson testified that the four tracts are underlain by a continuous geologic structure on the Norphlet Formation with a common gas pool. This is shown on Figure 5.3. Well 115-1 was the discovery well for this reservoir at a measured depth of 21,456 feet.

[81]These descriptions draw from company sponsored testimony at the AOGB and from Bulletin 140 of the AOGB. Mink, Robert M., Berry Tew, Steven Mann, Bennett Bearder, and Ernest Mancini, "Norphlet and Pre-Norphlet Geologic Framework of Alabama and Panhandle Florida Coastal Waters Area and Adjacent Federal Waters Area," AOGB Bulletin 140, 1990.

[82]AOGB Docket 4-14-929.

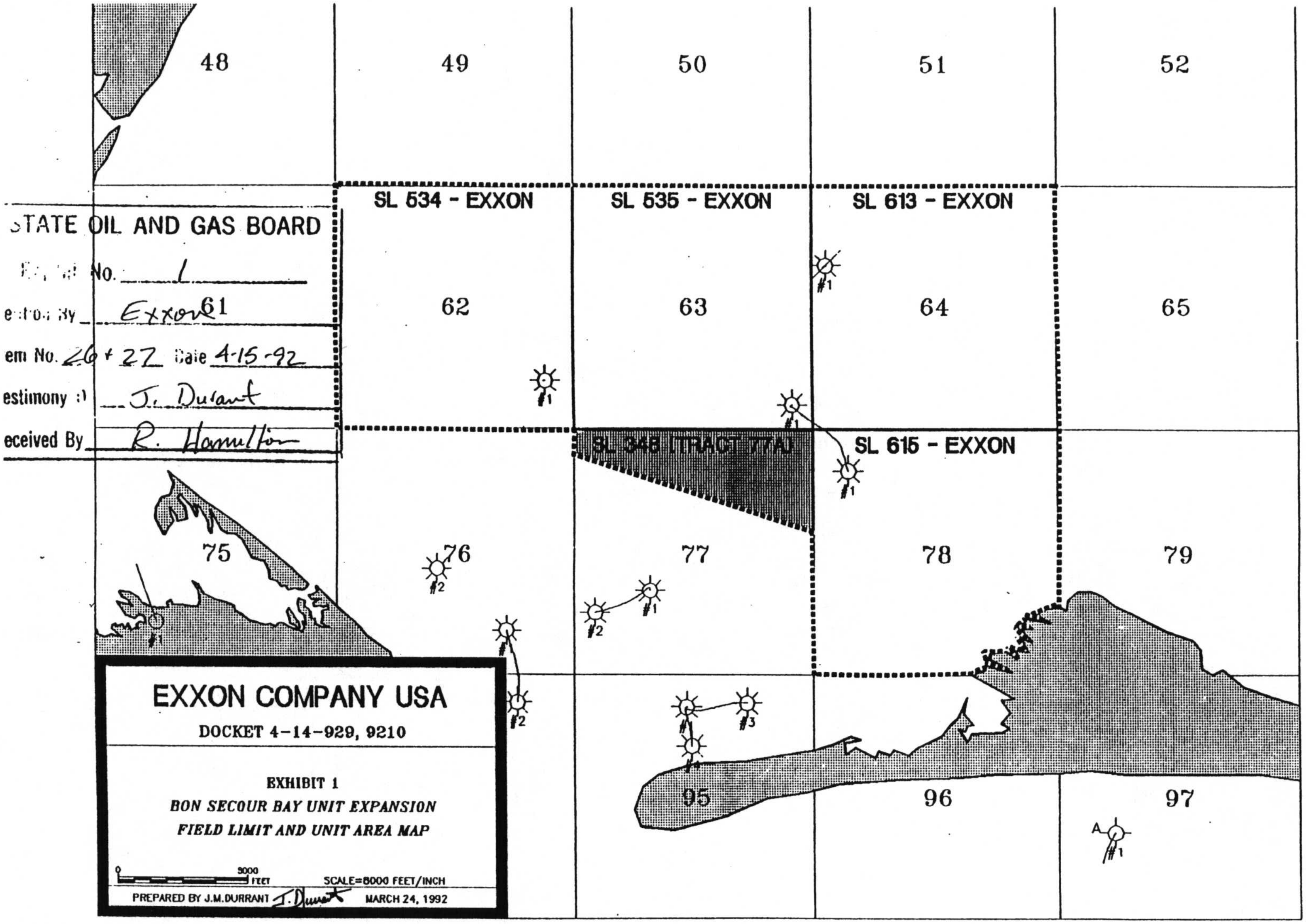


Figure 5.1. Bon Secour Bay Field Limits.

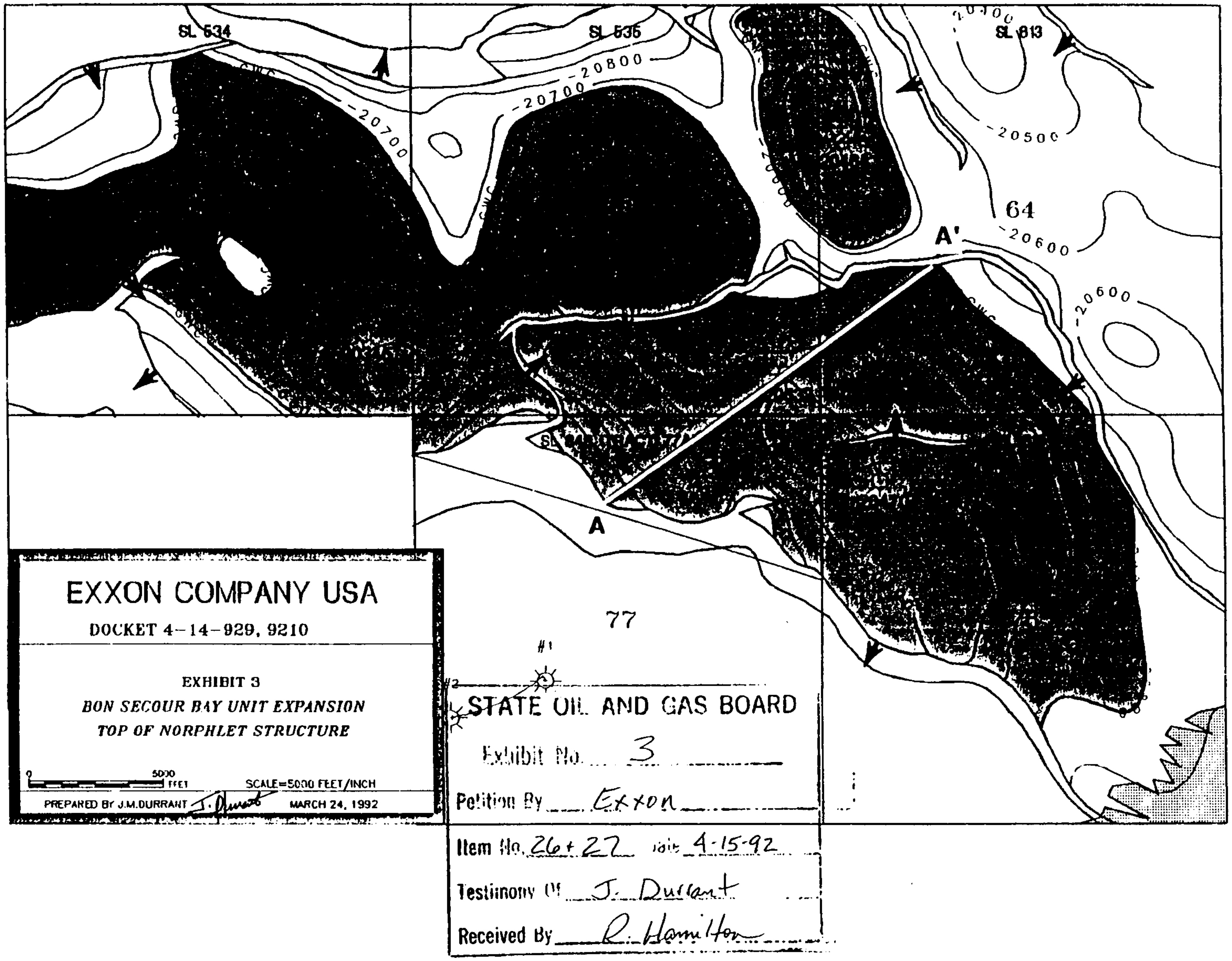


Figure 5.2. Bon Secour Bay: Top of Structure.

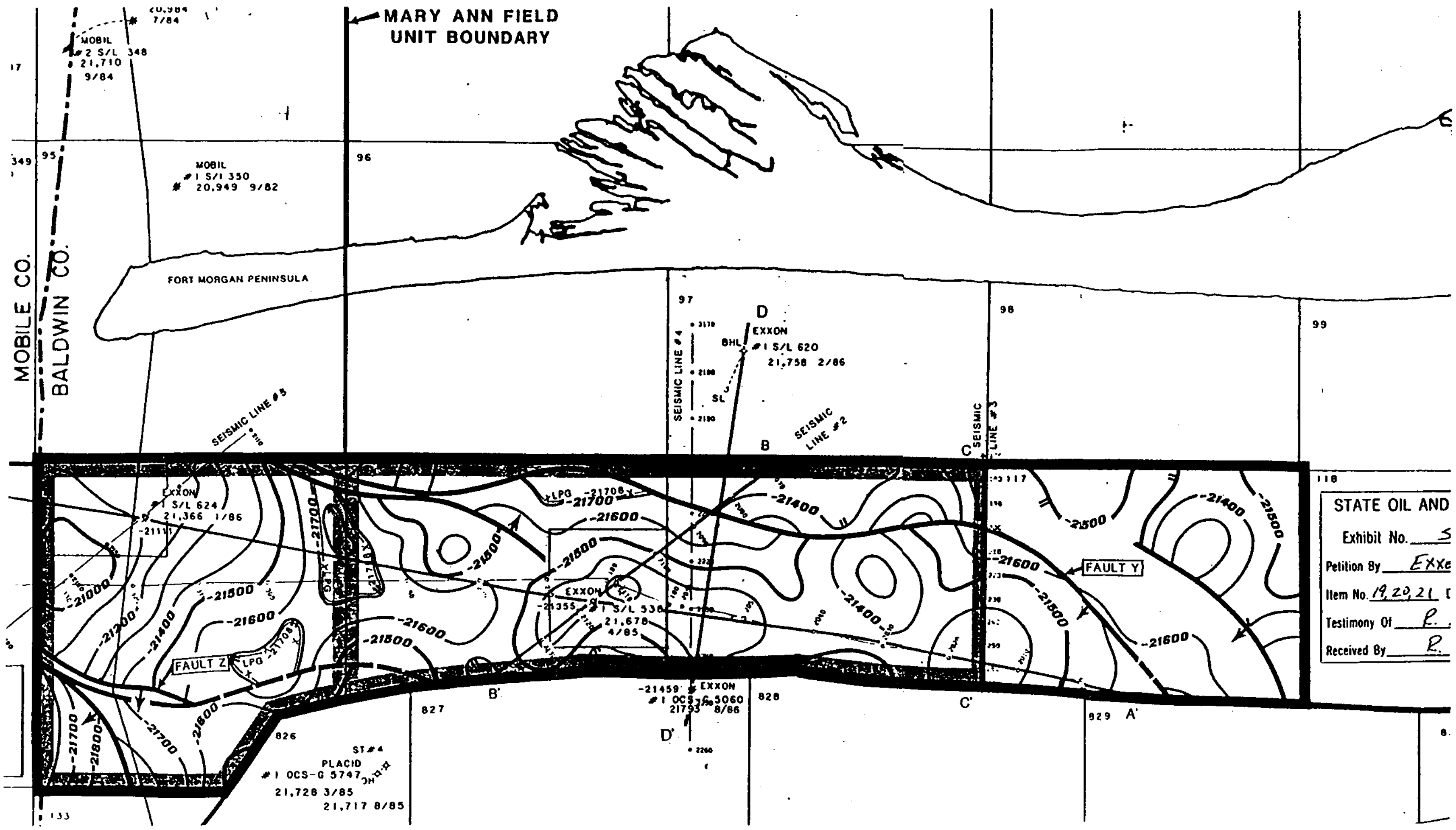


Figure 5.3. North Central Gulf Field Structure.

The Exxon witness testified that the gas reservoir on OCS tract 827 is a part of the same reservoir underlaying tracts 114 and 115. The reservoir is defined on the southwest of tract 114 by the fault labelled Fault Z. The fault can be seen running into tract 113, Shell's lease. Placid's well in OCS tract 826 was water bearing proving that Fault Z seals the reservoir on the south. The northern edge of the reservoir is defined by Fault Y on Figure 5.3. Well 97-1 north of the fault was water bearing, proving that the reservoir is sealed by Fault Y, which also seals the eastern edge of the reservoir.

The hydrocarbon trap in the field is the elongated east-west trending salt anticline, truncated on the north and east by Fault Y, which extends northwesterly into Mobil's tract 95. The Norphlet formation is thinner in the North Central Gulf than in the other offshore Norphlet fields, ranging from 120 to 160 feet. Eolian dune sandstone comprises the depositional environment.

The wellstream analysis shows that Exxon's North Central Gulf Field produces gas with carbon dioxide concentrations typical to other local Norphlet fields, but with much lower in H_2S concentration than the Bon Secour Bay and Lower Mobile Bay Fields—between 300 and 650 ppm as shown on Table 5.1. This proves that the field is not in contact with the reservoir in the contiguous Mary Ann Field. Exxon testified that the gas in tract 112 contained 40 times higher concentration of H_2S than measured in tracts 114 and 115.

Table 5.1
Exxon Wells 115-1 & 114-1 Full Wellstream Analyses

Component	**S/L 538 No. 1 Tract No. 115**	**S/L 625 No. 1 Tract No. 114**
Methane	87.8094	81.6009
Ethane	5.1768	8.1108
Propane	1.8705	4.0283
iso-Butane	0.5377	1.2805
n-Butane	0.3583	0.8869
iso-Pentane	0.1110	0.3143
n-Pentane	0.0436	0.1245
iso-Hexane	0.0065	0.0366
n-Hexane	0.0034	0.0178
Heptanes Plus	0.1015	0.2750
Hydrogen Sulfide	0.0030	0.0065
Nitrogen	0.1375	0.1597
Carbon Dioxide	3.8408	3.1582
	100.0000	100.0000

Source: Alabama Oil and Gas Board, Exhibit 14, Petition by Exxon, Item No. 19,20,21 dated 9-4-86.

In 1993, Exxon returned to AOGB to propose that the North Central Unit be partitioned into a 114 Unit and a 115/116 Unit. The proposed 114 Unit is shown on Figure 5.4 to include tract 114 and the northeast corner of tract 113. Exxon witness Martin Fleckenstein testified that the "Tract 114 gas reservoir is separated from the North Central Gulf Unit consisting of Tracts 115 and 116 by an interdune area with no reservoir sand present."[83] Exxon's 114 wells are shown as well as Shell's five producing wells.

Figure 5.5 shows the reservoir structure underlaying tracts 113 and 114. Sealing faults in tract 113 and on the northeast of 114 are described as defining the reservoir structure. Figure 5.5 does not depict the extension of the structure into MOEPSI's tract 95, but no indicated sealing fault is shown. Figure 5.6 depicts the deposition of the sands that typically form the Norphlet structures. The darker areas represent the thicker sand; the white area represents the interdunal area in which Exxon's well 114-1 found gas that flowed at only 1.2 MMCFD in 1985. The witness stated "The Norphlet formation in the Mobile Bay area including the tract 114 Unit was deposited as large linear dunes in a desert environment. These sand dues consisted of thick parallel sand bodies oriented northwest to southeast that were separated by thin interdune areas. This depositional style is responsible for the characteristic thick-thin geometry of the Norphlet in the Mobile Bay area including tract 114."[84]

5.3 Exxon Northwest Gulf Field

The Northwest Gulf Field was named and defined by AOGB Order 86-269 in Docket 11-21-86 to include tracts 110, 111, 112 and 131. It was amended to exclude tract 110 in Docket 9-19-873. Testimony in the 1987 docket showed that tracts 111, 112 and 131 are underlain by a common Norphlet gas pool. Well 112-1 was tested December 1984 at 21,500 feet as the discovery well. Figure 5.7 shows the common structure that underlies the three tracts but does not show structural interpretation on other operators' (Mobil and Shell) adjacent leases, although the structures can be inferred to extend into OCS 823. The structural interpretation extends into Exxon's then-owned tracts 90, 91 and 92 to show the fault complex that separates the Northwest gas pool from areas to the north. Exxon well 91-1 encountered water north of Fault Y which is visible on the figure proving that the fault defines the northern boundary of the gas pool under 111 and 112.

The hydrocarbon trap is an east-west trending, faulted salt anticline. The dune sandstone in the reservoir is predominantly eolian deposition with an average thickness of about 400 feet.

5.4 Shell Fairway Field

AOGB Order 86-280, Docket 11-21-86, established the Shell Fairway Field consisting of tracts 113 and 132. Testimony in Docket 12-13-90165 by Mr. R. J. Stancliffe described the basis for the unitized area of the revised Fairway Field. Figure 5.8 shows the location of the structures underlaying tracts 113 and 132 along with wells drilled and proposed in 1990. Figure 5.9 shows

[83]AOGB Docket 11-9-937, p. 287.

[84]AOGB Docket 11-9-937, p. 295.

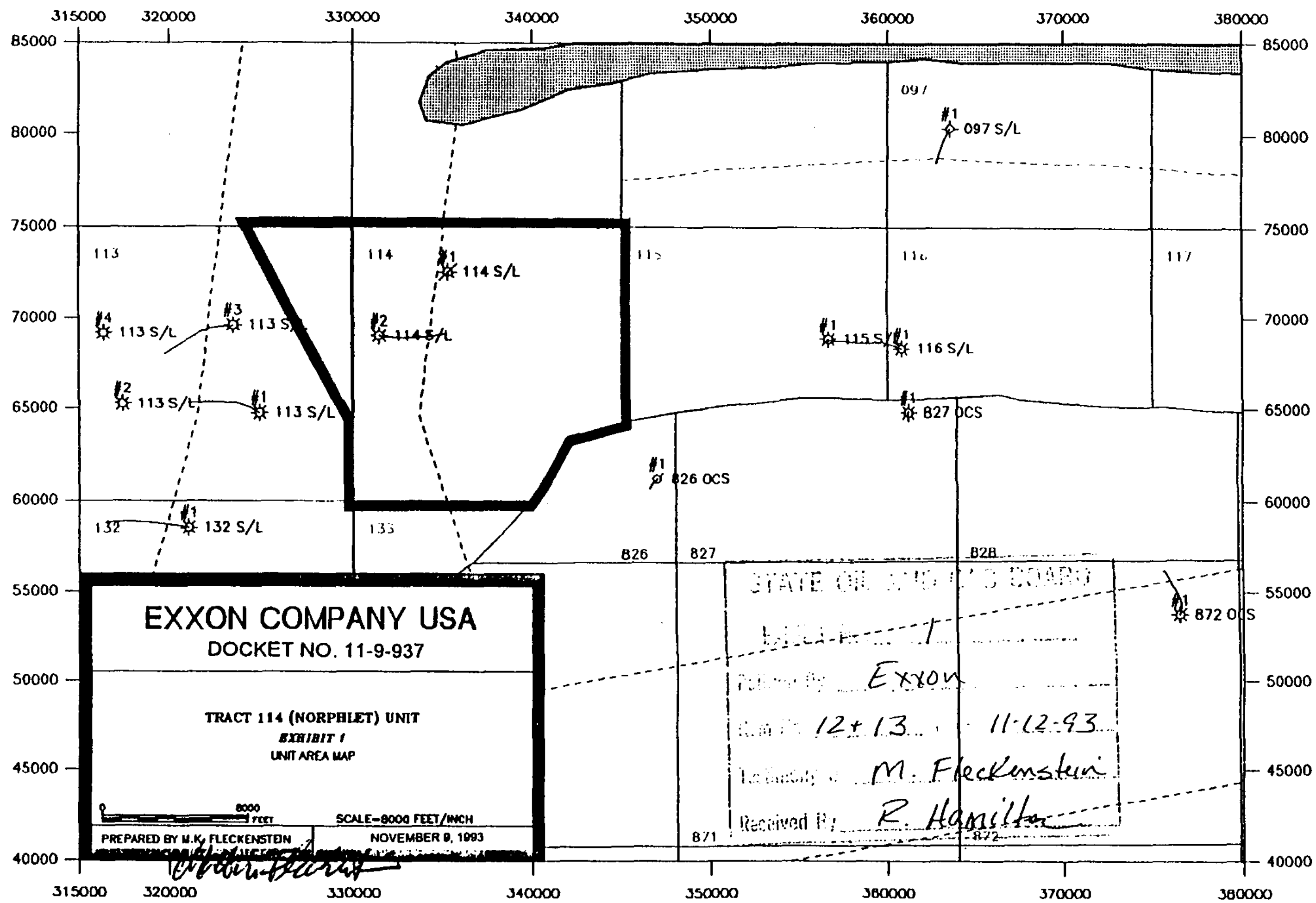


Figure 5.4. Exxon Tract 114 Unit Expansion.

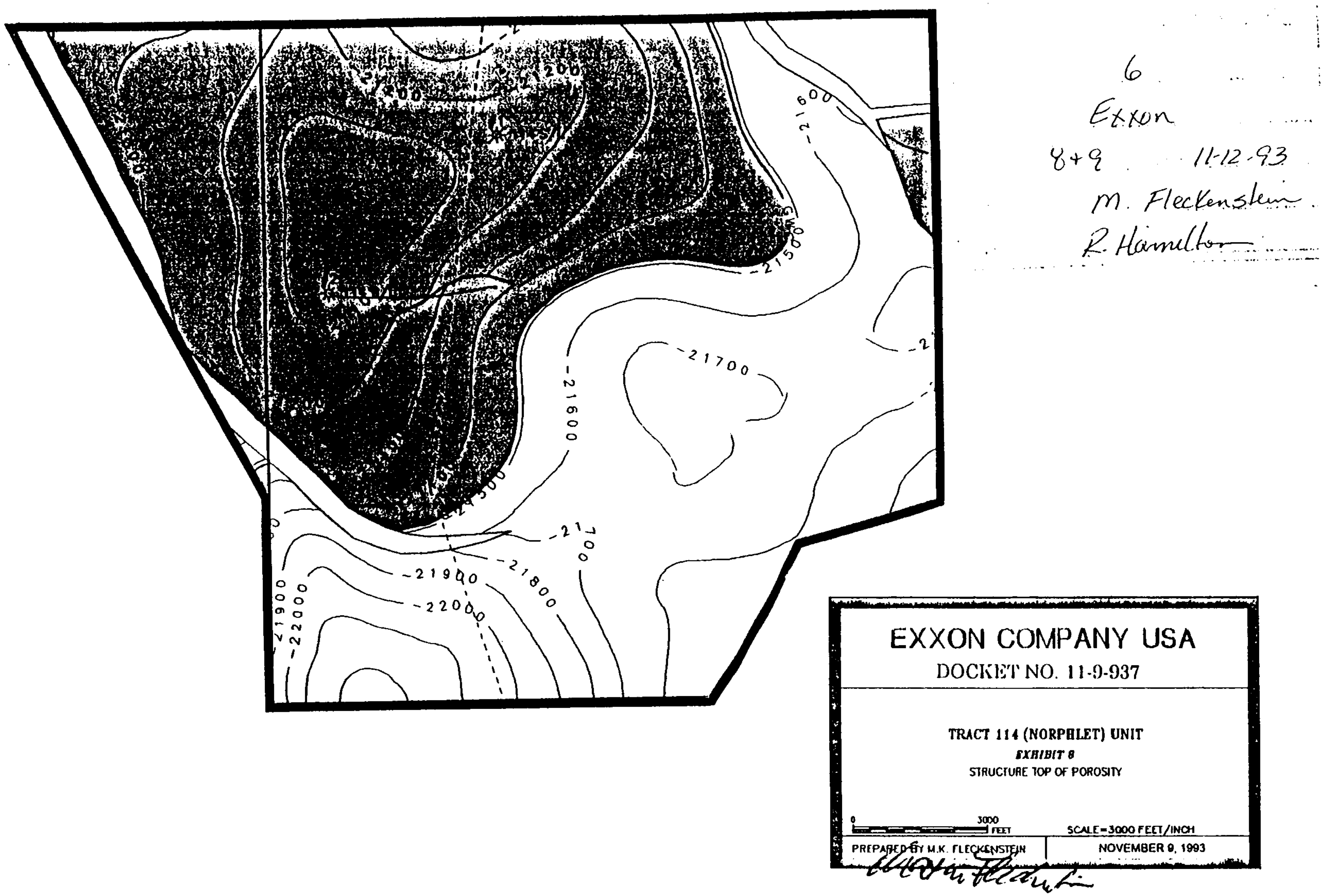


Figure 5.5. Exxon Tract 114 Reservoir Structure.

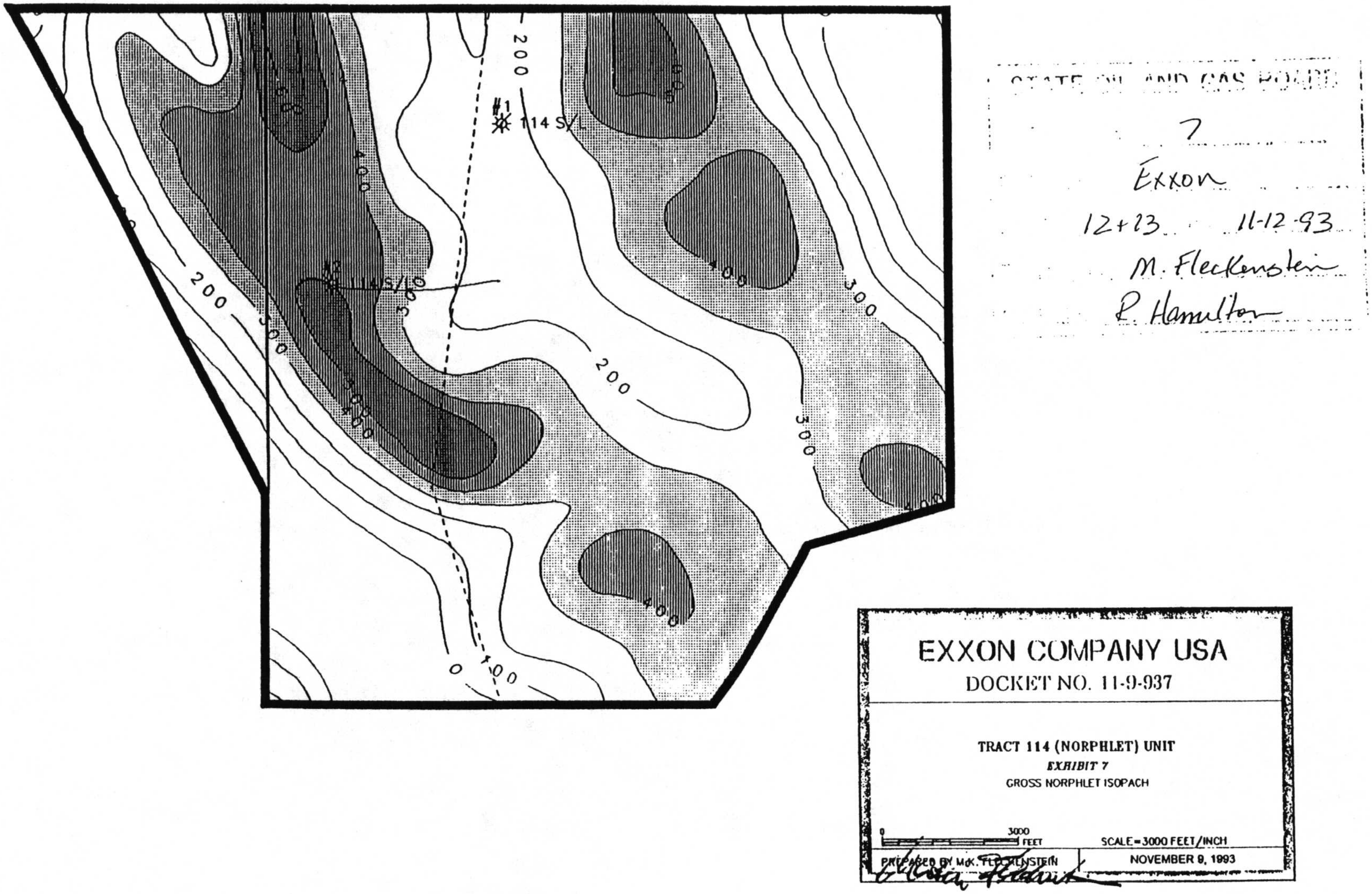


Figure 5.6. Exxon Tract 114 Reservoir Dunes.

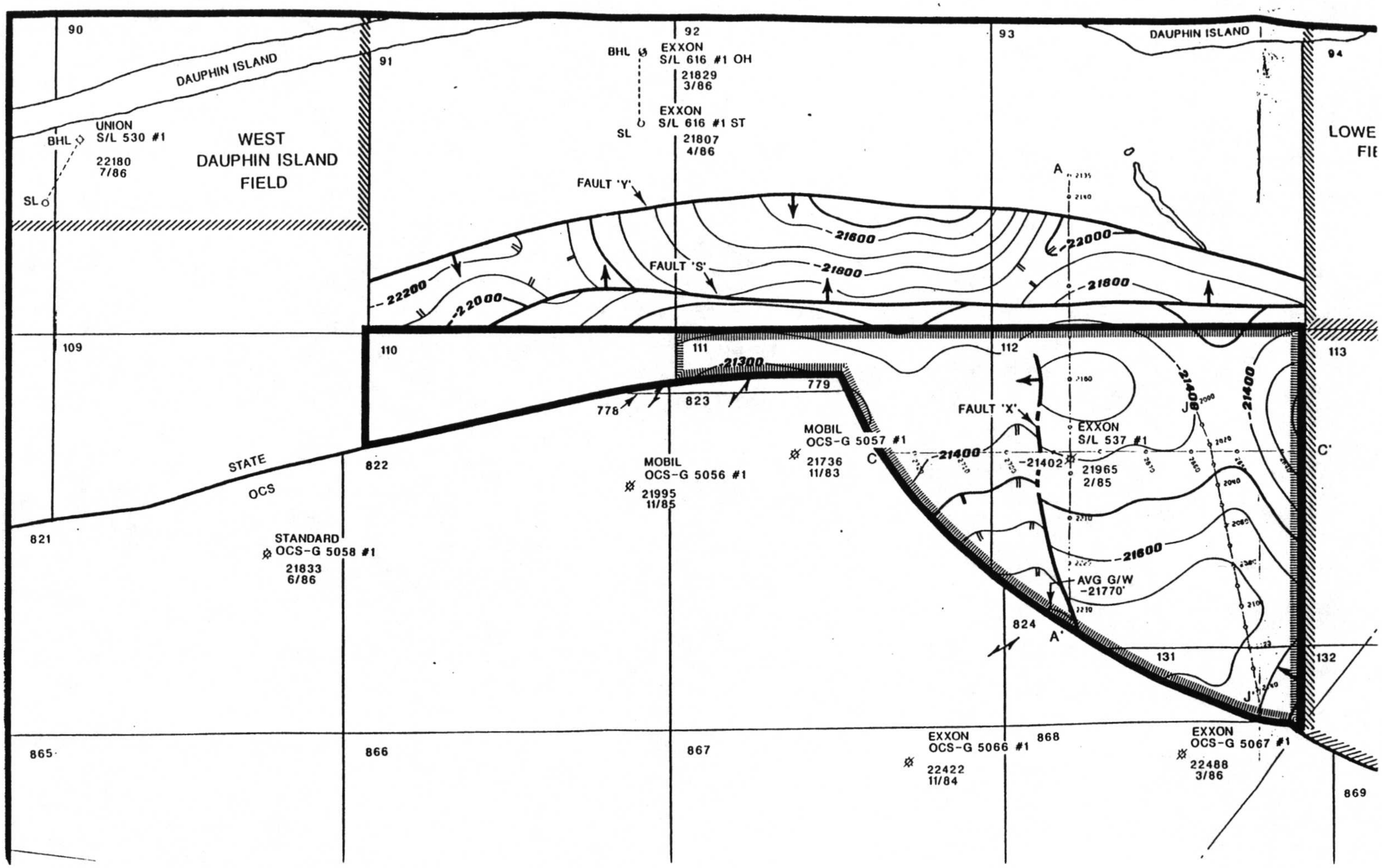


Figure 5.7. Exxon Northwest Gulf Structure.

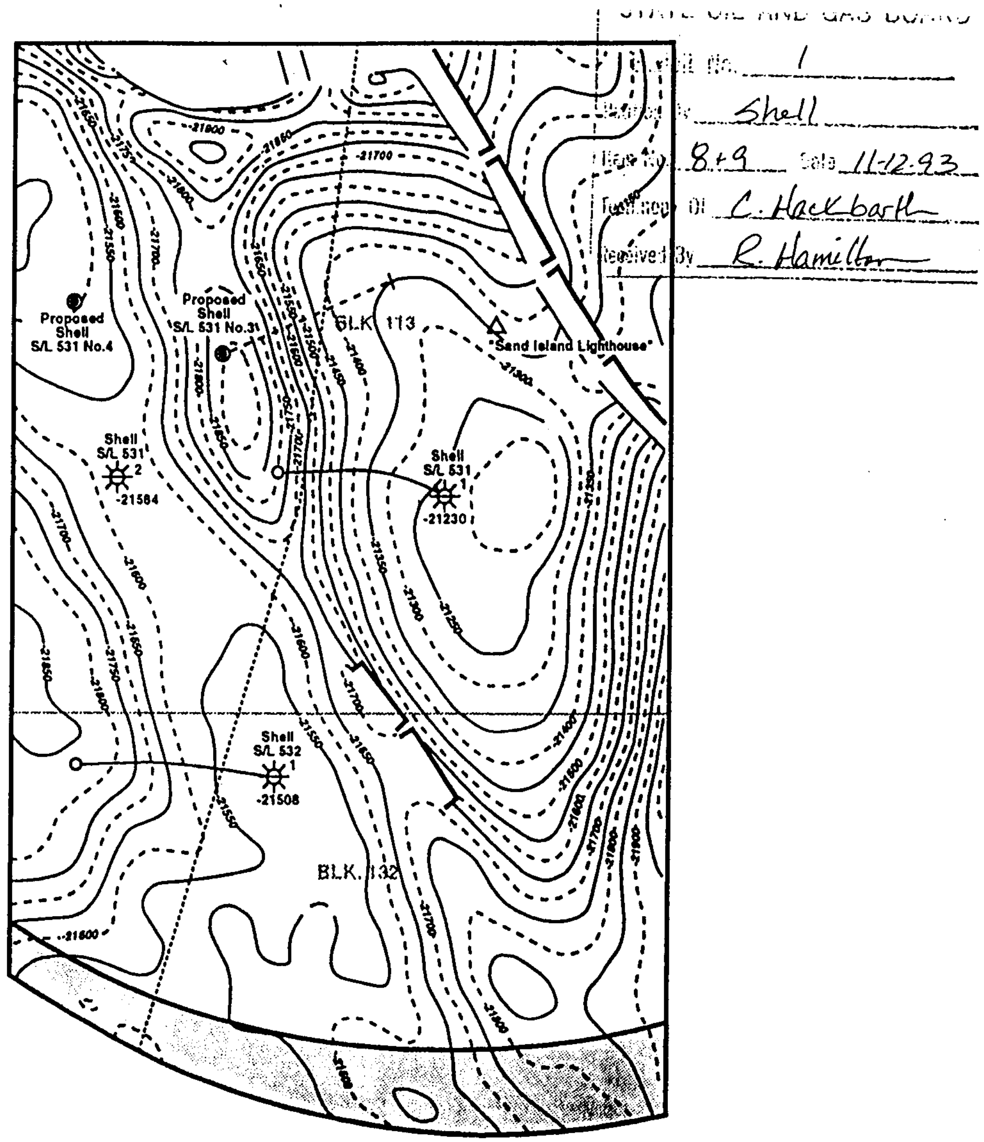


Figure 5.8. Shell Fairway Field Structure.

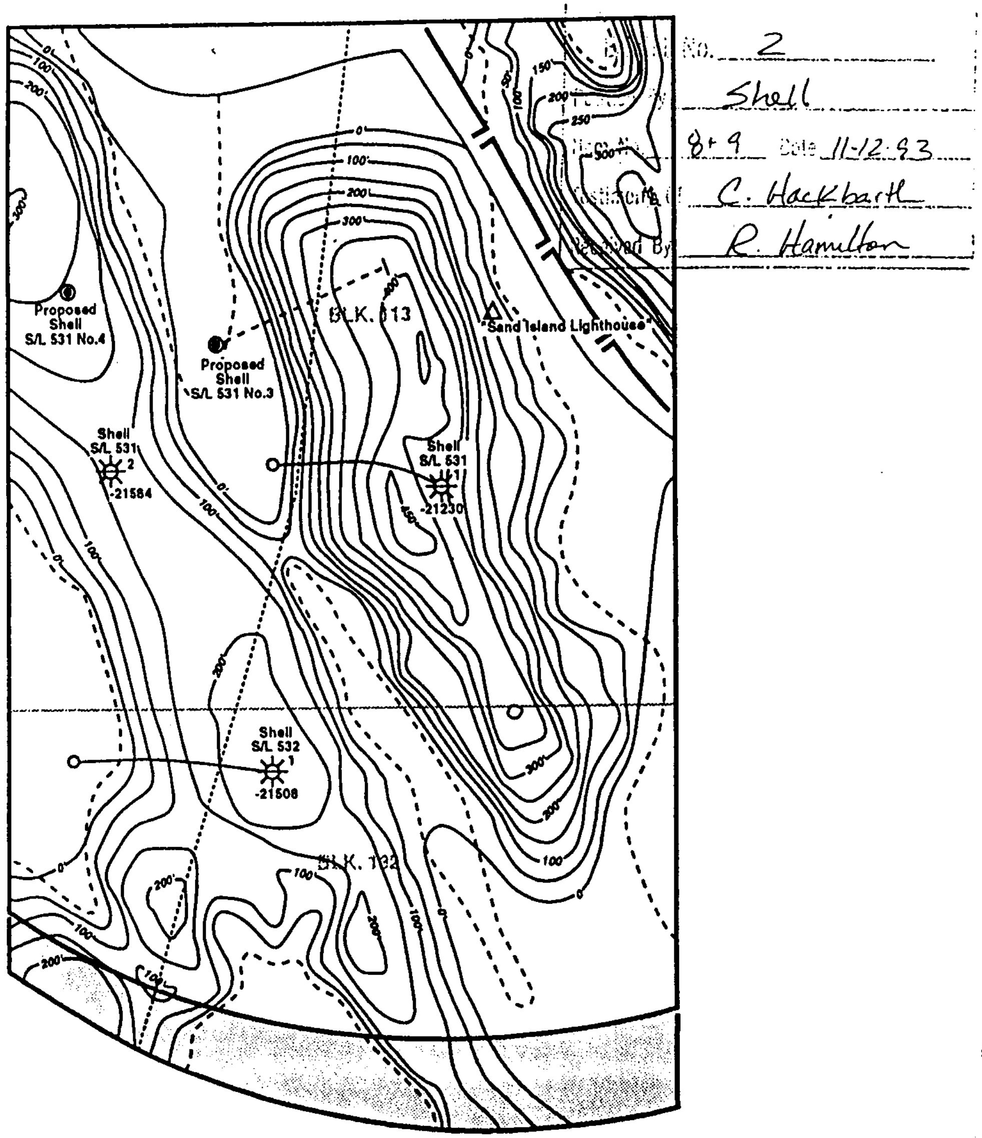


Figure 5.9. Shell Fairway Field Dunes.

that tracts 113 and 132 "consist of two Norphlet pods of varying thicknesses which extend into and across both tracts. . . . [T]he Norphlet has very good reservoir characteristics both in terms of porosity and permeability . . . [and] excellent lateral continuity which we feel equates to an extensive per well lateral drainage capability."[85]

The fault that separates the Fairway Field Unit from the 114 Unit is visible on Figure 5.8. Shell's witness stated that the bottomhole pressures between the 113-1 and the 114-1 differ by greater than 2000 psi, suggesting different reservoir accumulations. The witness also stated that a large fault located along the northern border of tract 113 separates Shell Fairway from the Mary Ann Field. The hydrocarbon trap in the Fairway Field salt anticline trends northwest-southeast.

Mr. Len Falsone testified that Shell intended to develop the field with five wells producing 40 MMCFD each beginning in the fall of 1991. These flow rates were thought to be high but consistent with reservoir properties and comparable data from Mobil tract 823-3 well which was tested at 62 MMCFD in 1990.

In 1993, Shell appeared with Exxon to confirm that the northeast corner of 113, separated by the fault is in a common Norphlet pool with the Exxon 114 Unit. Shell witness Claudia Hackbarth confirmed that the reservoir northeast of the fault in 113 extends to the "adjacent tracts to the north and east leased by Mobil and Exxon,"[86] as shown on Shell Figure 5.10. She further testified that "Exxon's tract 114-2 well will likely drain the entire central pool shown in this cross section."[87] This statement preceded Mobil's well 95-5 into the same reservoir. The location of MOEPSI's well 95-5 (not shown on the figure) in the southwest corner of MOEPSI's tract 95 clearly penetrates the common reservoir.

5.5 MOEPSI Aloe Bay Field

Mobil's Aloe Bay Field was established by AOGB Order 92-17 in Docket 2-6-92 to include tracts 74, 75 and parts of 92 and 93. The field is located west of the Mary Ann Field as shown on Figure 5.11. Mr. Peter Andronaco appeared as Mobil's witness to demonstrate that the Aloe Bay Field was discovered by well 75-1 and underlies much of Dauphin Island as can be seen on Mobil Figure 5.12. Figure 5.13 is the structure map of the Norphlet Formation in the Aloe Bay Field. The two westernmost Mary Ann wells 76-1 and 76-2, the 91-1 well and the Aloe Bay discovery well 75-1 are shown on the figure. The witness explained that "the structure tested by the 75-1 well is a syncline separated from both the Mary Ann Field structure to the east and the Tract 91-1 and 91-1ST wells to the west. . . . The gas-water contact associated with the Tract 75-1 discovery well is distinctly different from the gas-water contacts in the gas accumulation to the east and to the west. The 75-1 contact of 21,012 feet subsea is 133 feet shallower than the water contact in 91-1ST well to the west and 136 feet deeper than the water

[85]AOGB Docket 12-13-90165, p. 405-406.

[86]AOGB Docket 11-9-933, p. 266.

[87]AOGB Docket 11-9-933, p. 268.

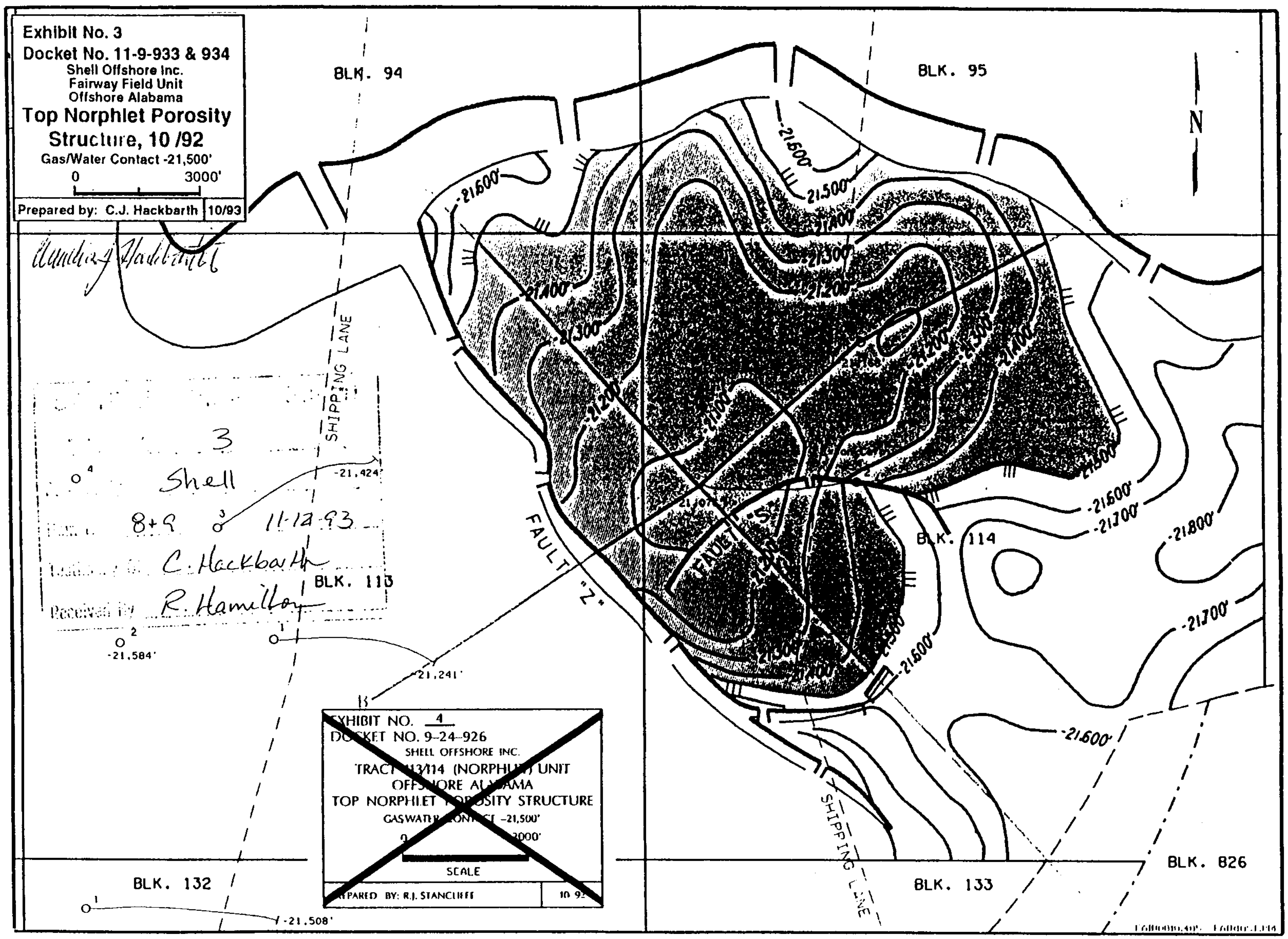


Figure 5.10. Exxon & Mobil Common Structure.

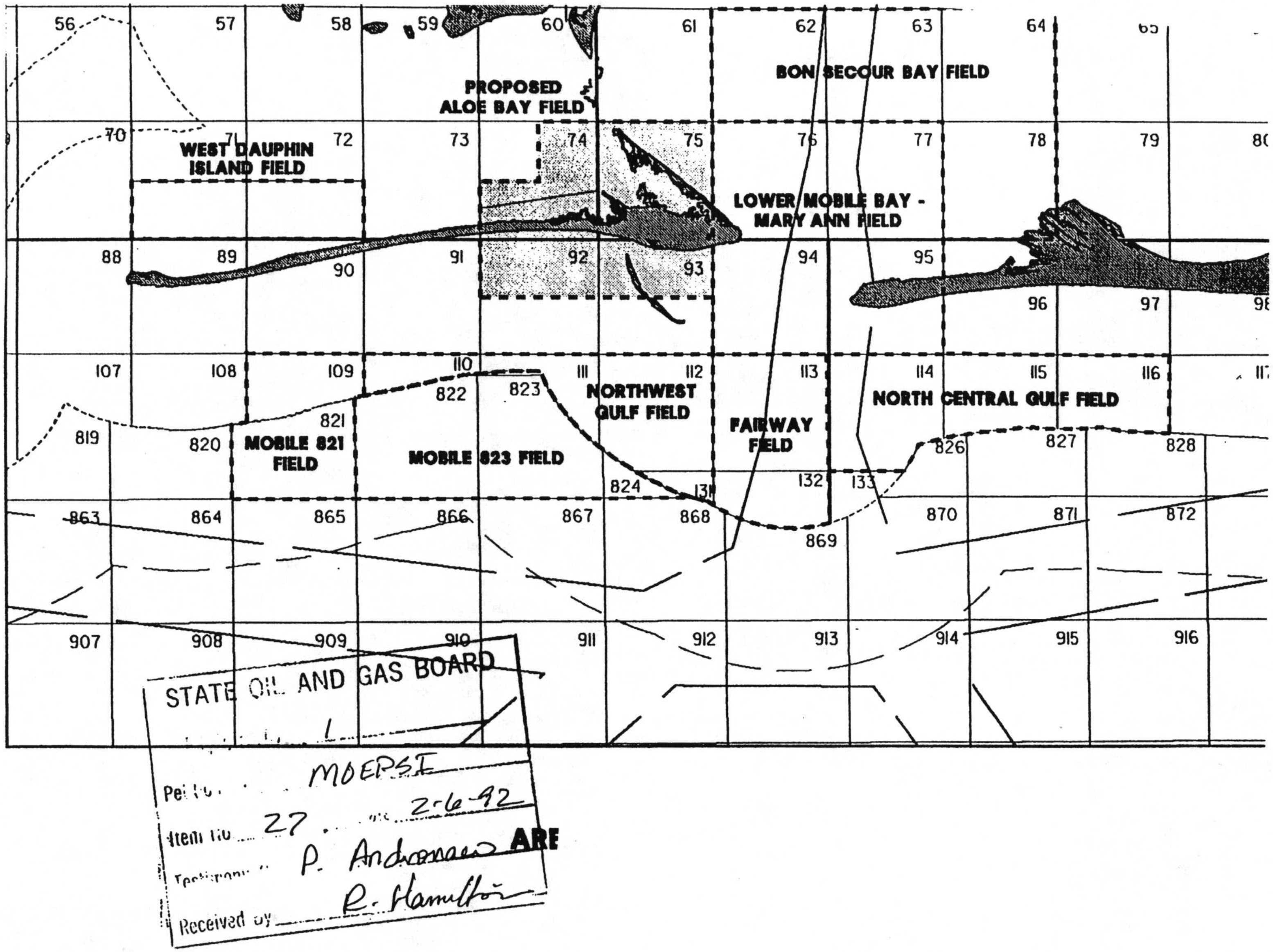


Figure 5.11. Mobil Aloe Bay Field Location.

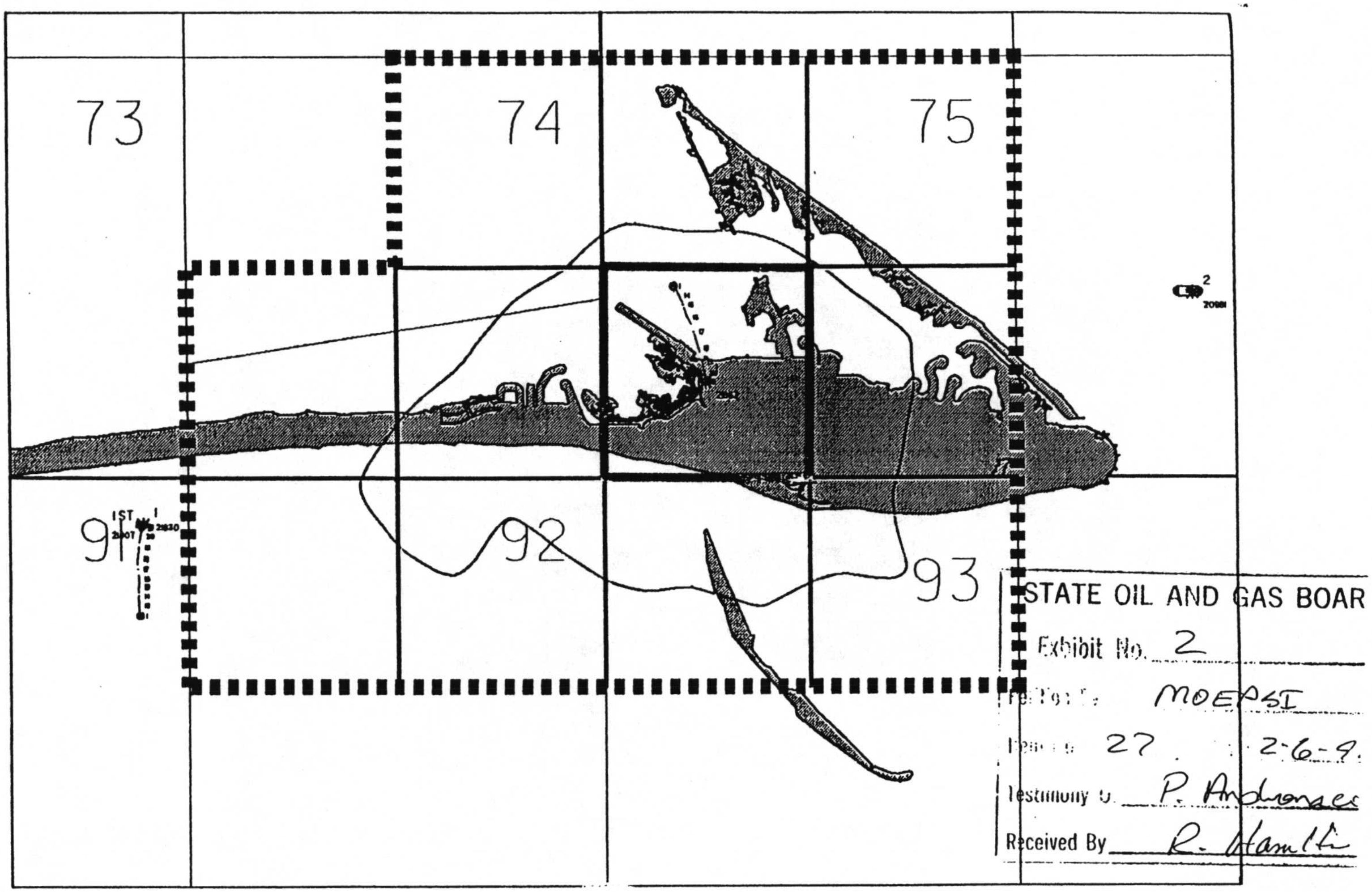


Figure 5.12. Mobil Aloe Bay Field.

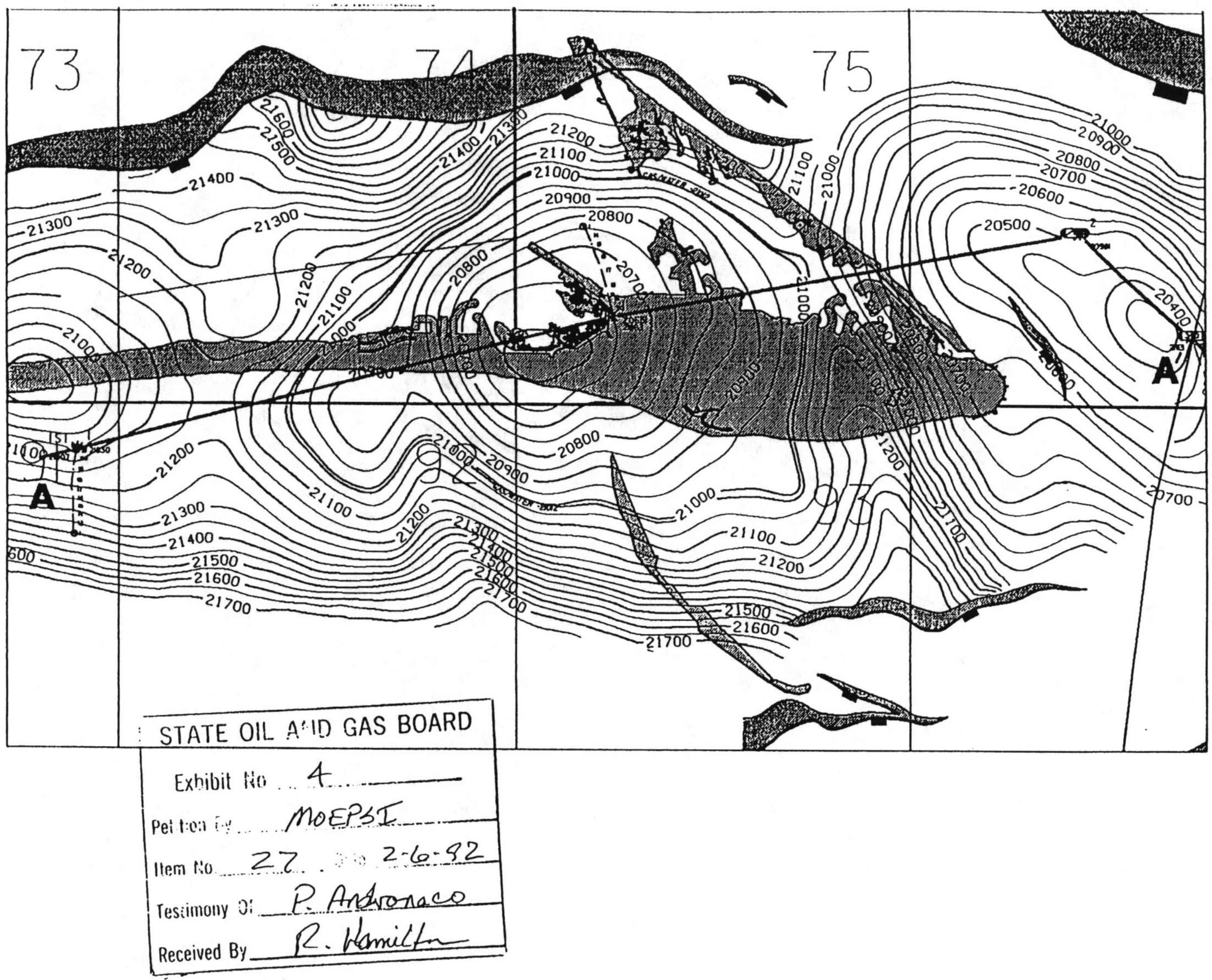


Figure 5.13. Mobil Aloe Bay Top Norphlet Structure.

contact established in the Mary Ann Field to the east. . . . Norphlet gas accumulation in the Aloe Bay Field is separate and distinct from both the Mary Ann Field and the 91 sidetrack."[88]

Full wellstream analysis of the test demonstrated that Aloe Bay gas is 8.4 percent H_2S, as shown on Table 5.2. The gas is sour like the Mary Ann Field gas.

Mobil's Mary Ann Field gas plant was debottlenecked in 1996-1997 with an oxygen plant to double its sulfur handling capacity to 480 LT per day to handle the Aloe Bay gas. Aloe Bay was completed and brought on line during late summer 1997.

Table 5.2
Aloe Bay Well 75-1 Full Wellstream Analysis

Component	State Lease 701 No. 1 Tract 75
Methane	87.13
Ethane	0.16
Propane	0.00
iso-Butane	0.00
n-Butane	0.00
iso-Pentane	0.00
n-Pentane	0.00
iso-Hexane	0.00
Heptanes Plus	0.00
Hydrogen Sulfide	8.37
Nitrogen	1.00
Carbon Dioxide	3.34
	100.00

Source: State Oil and Gas Board, Exhibit 7, Petition by MOEPSI, 2/6/92.

5.6 Lower Mobile Bay—Mary Ann Field: Revisited

Lower Mobile Bay-Mary Ann Field was established by AOGB Order 80-209 and amended to excise the northeast corner of tract 77 on April 15, 1992. Mobil reappeared July 17, 1996 to amend the Special Field Rules to "recognize the existence of the new pool within the unit area . . . a new Norphlet pool in the Mary Ann Unit and Field . . . in the same strata that can be

[88]AOGB Docket 2-6-924, p. 150, 153.

correlated with the Norphlet formation in the State Lease 347 Well [76-1]."[89] Figure 5.14 shows the wells that Mobil has drilled in the four leases. Mobil's witness Bob Jorden described the development of the southern portion of Tract 95 beginning with the spudding of the 95-5 well in July of 1994, which deviated 7400 feet east from a rig located outside the shipping fairway in tract 94. The well was eventually sidetracked to a better location 8100 feet east of the rig reaching total depth in October 1995. Platform 94-C was installed in late 1996 and production began in November 1996.

Figure 5.15 shows the general northwest-southeast trending dune structures that characterize the eolian Norphlet sands that Mobil's witness Mr. Gerald Greiner explained. "Contour intervals illustrate the broad anticlinal nature of the Norphlet . . . reflecting the alternating depositional thins and thicks respectively of the Norphlet interdune and dune areas."[90] The figure also shows the fault to the south of tracts 94 and 95 (Exxon's fault Y shown on Figure 5.3) that separates the Mary Ann Field into two Fault Blocks, labelled "A" and "B." Mr. Greiner made the point that 3-D seismic data were able to produce the figure thereby "clarifying the top and base of Norphlet, enabling accurate characterization of the reservoir [and] profoundly changing the aerial distribution of the Norphlet verses the 1986 map."[91] Figure 5.16 shows the gross isopach map of the Norphlet to illustrate its classic dunal nature with thicks and thins within Mobil's four tracts. Figure 5.17 shows the geologic depth cross section on the Well 95-5 and 95-5ST to emphasize the effects of 3D seismic data on well placement. ". . . [C]onventional 2D seismic could be relied upon to supply information on structural position only. . . . Well locations are now planned to maximize both structural height and stratigraphic thickness."[92] Moving the well 800 feet further east from its original bottomhole location improved porosity from 11.7 percent to 12.8 percent and increased productivity of the well markedly.[93]

The ST well tested 77.3 MMCFD on October 23, 1995. Mobil's witness referred to the gas as "a Norphlet pool previously undiscovered in the Mary Ann Unit" and asked that Special Field Rules be amended to recognize the new pool as included within the Mary Ann Field and Unit.[94]

5.7 State Geologic Structures Summary

Figure 5.18, taken from the Gulf of Mexico Atlas, pulls together AOGB exhibits presented in this section. State Norphlet reservoir tops and wells are depicted as of 1994. No representations of federal areas are available. This structure map shows the magnitude of the state Norphlet area.

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[89]AOGB Docket 7-17-964, p.95-96.

[90]AOGB Docket 7-17-964, p. 119.

[91]AOGB Docket 7-17-964, p. 119.

[92]AOGB Docket, 7-17-964, p. 123.

[93]AOGB, Docket 7-17-964, p. 131.

[94]AOGB Docket 7-17-964, p. 144.

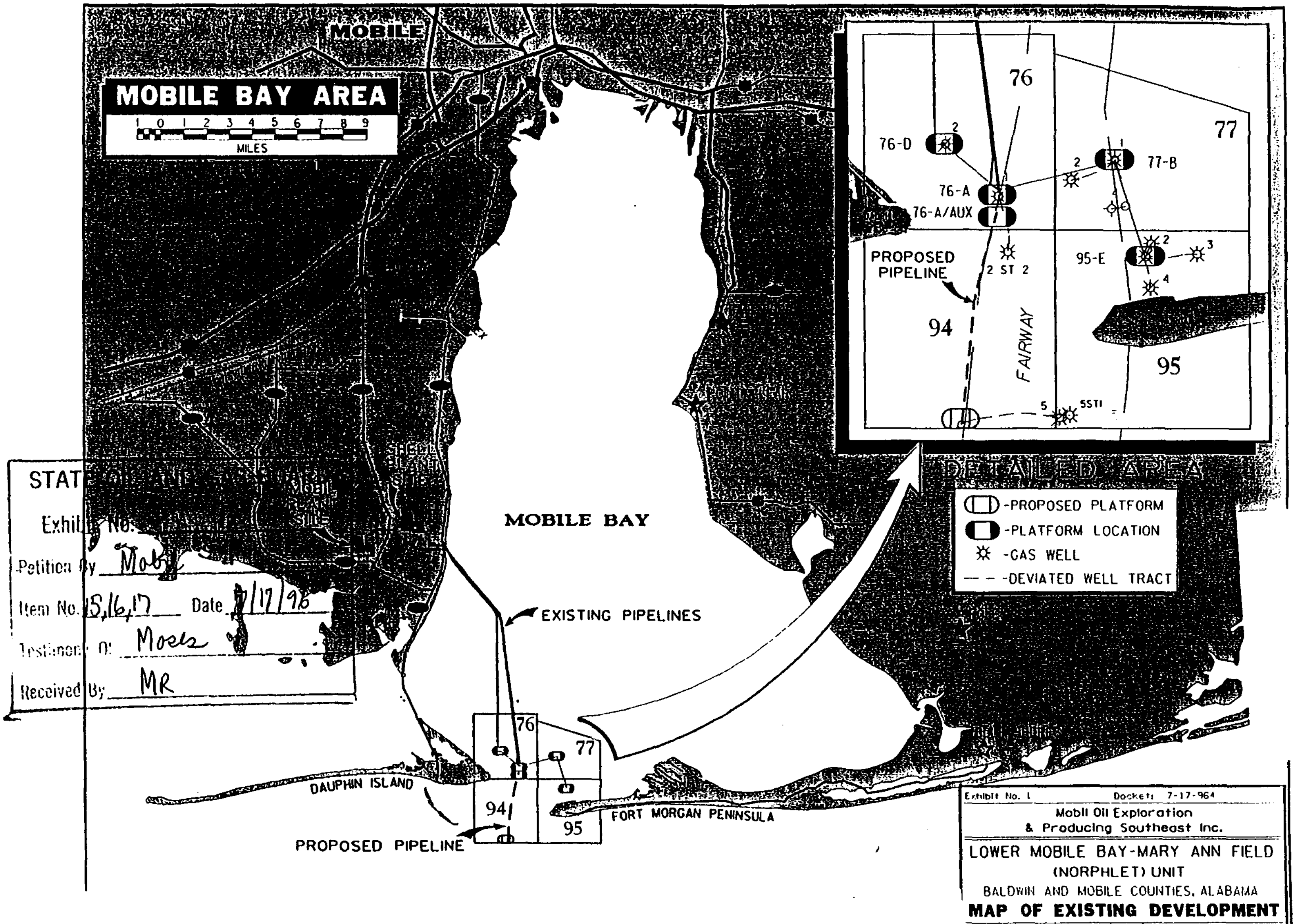


Figure 5.14. Map of Mary Ann Development.

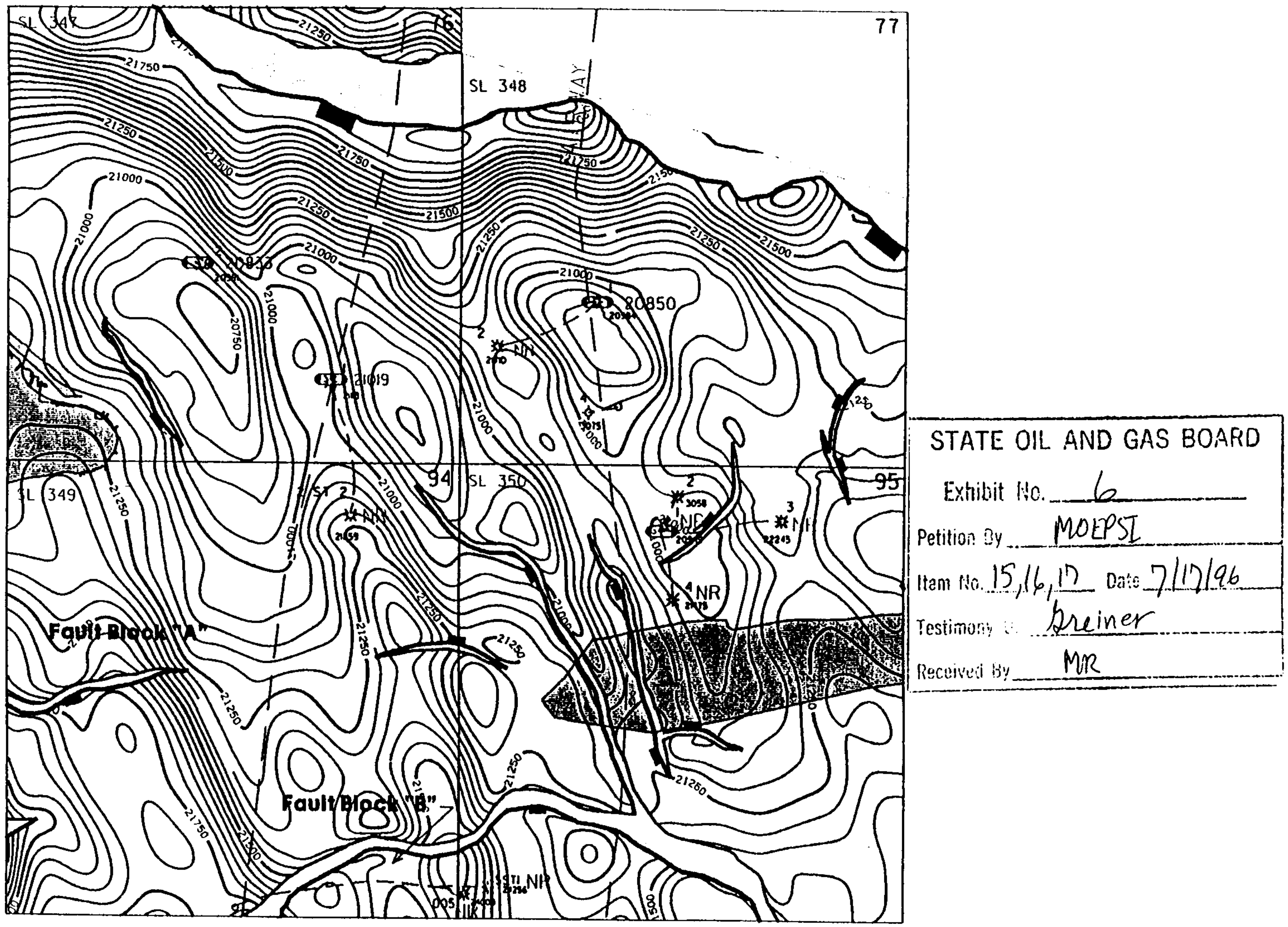
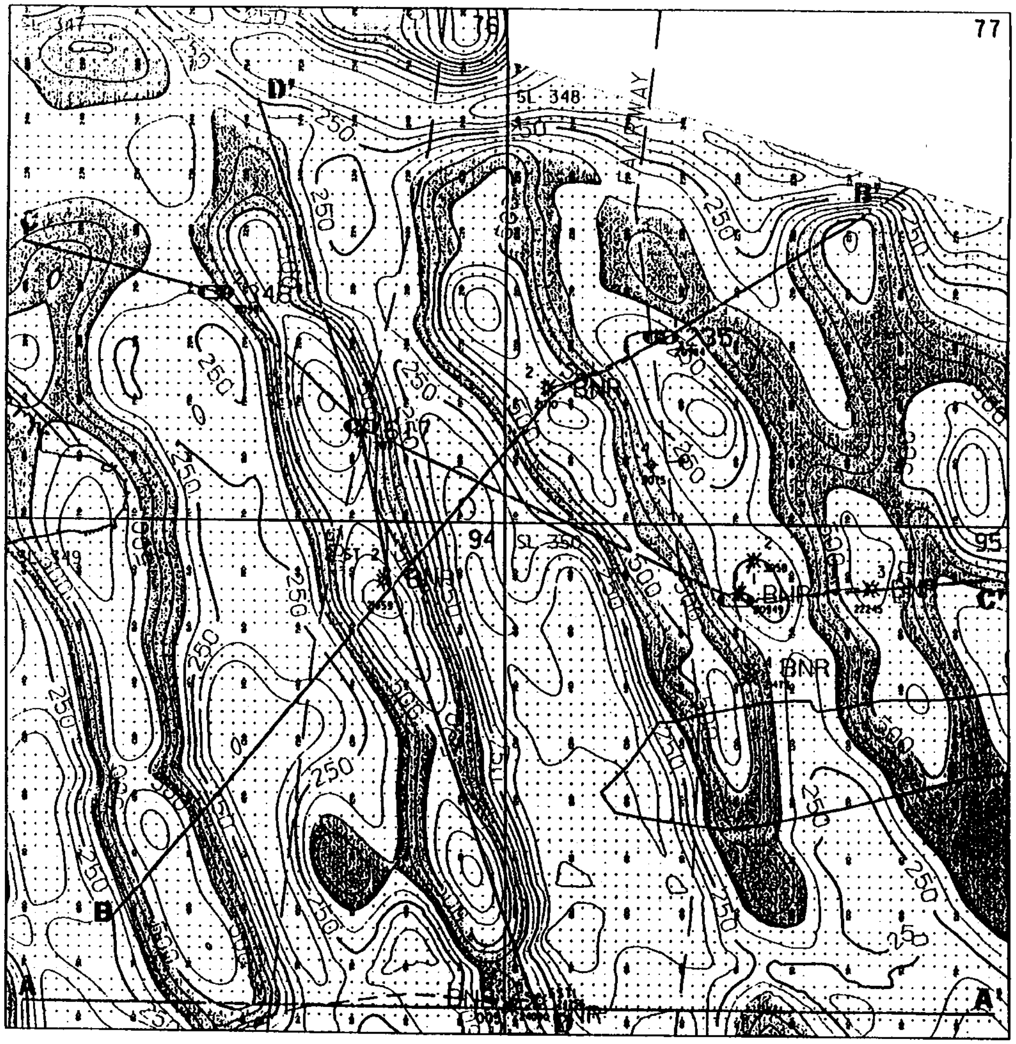
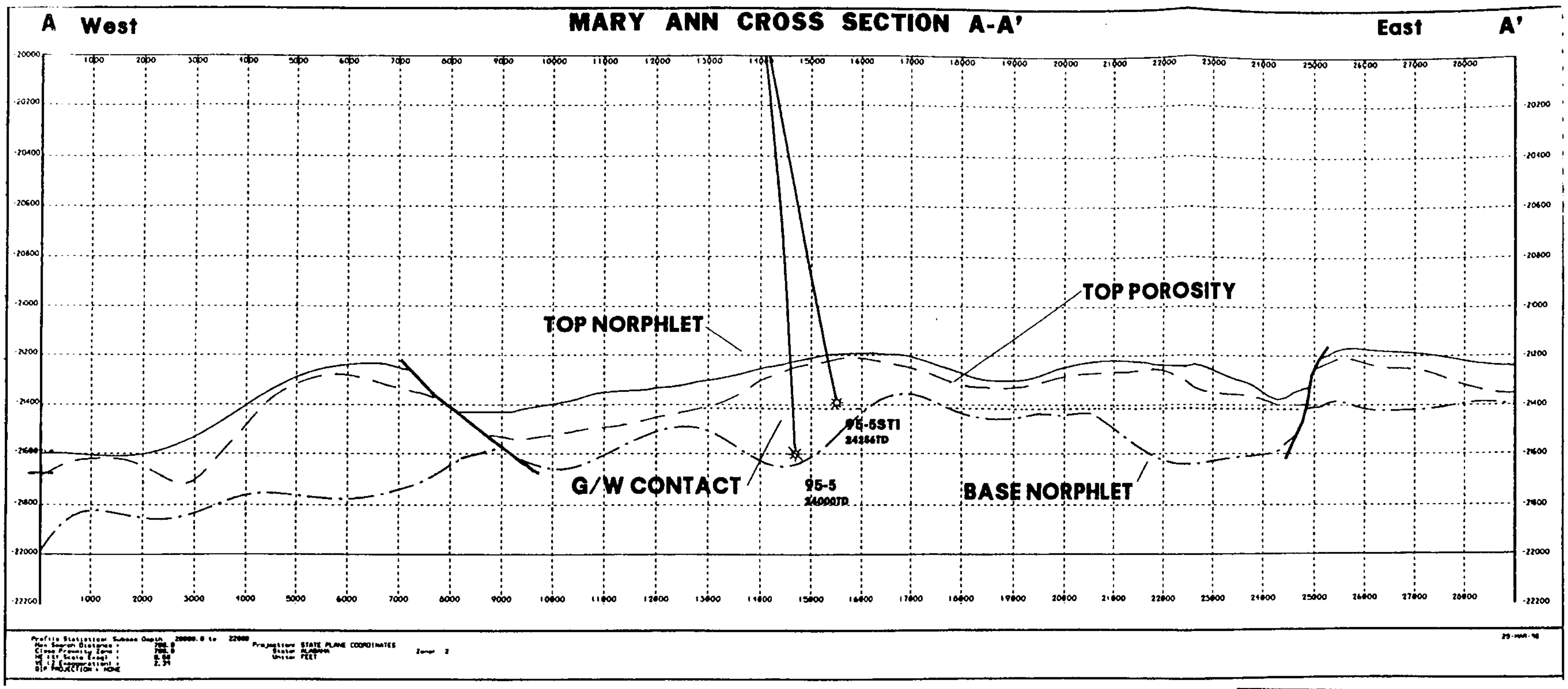


Figure 5.15. Mobil Mary Ann Field Base Norphlet Structure.



STATE OIL AND GAS BOARD
Exhibit No. 7
Petition By MOEPSI
Item No. 15,16,17 Date 7/17/96
Testimony Of Greena
Received By MR

Figure 5.16. Mary Ann Field Norphlet Gross Isopach.



STATE OIL AND GAS BOARD
Exhibit No. 9
Petition By MOEPSI
Item No. 15,16,17 Date 7/17/96
Testimony Of Greiner
Received By MR

Figure 5.17. Mobil Mary Ann Cross Section-95-5.

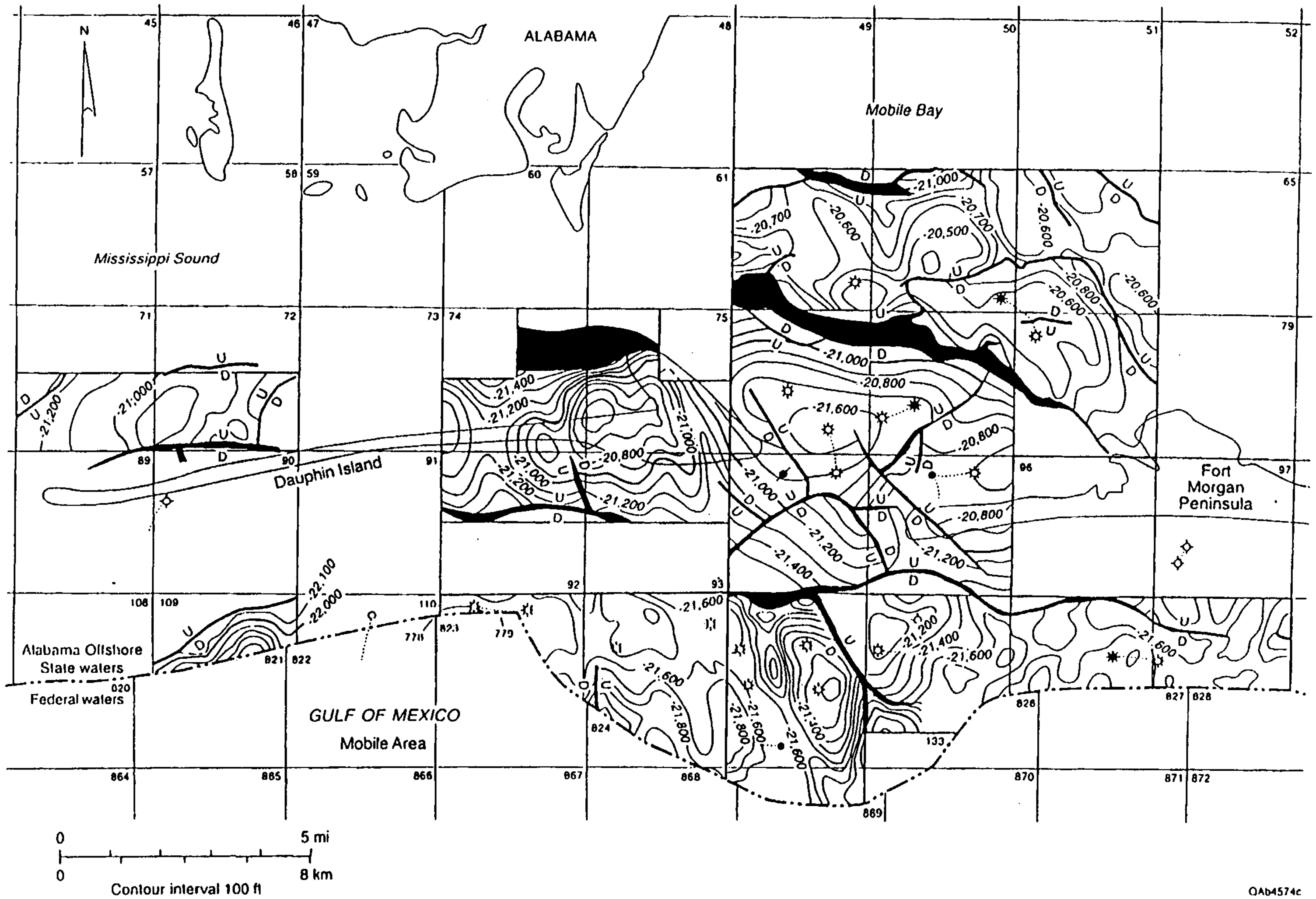


Figure 5.18. Alabama Norphlet Structure Map.

Source: U.S. DOI, MMS, 1994.

Figure 5.19 gives a view of the areal extent of the Coastal Alabama Norphlet play, which extends southeast towards Destin Dome, and west-southwest toward Union's 904 Field. The area directly south of Mobile Bay mostly has been explored and no economic reservoirs of Norphlet gas have been found.

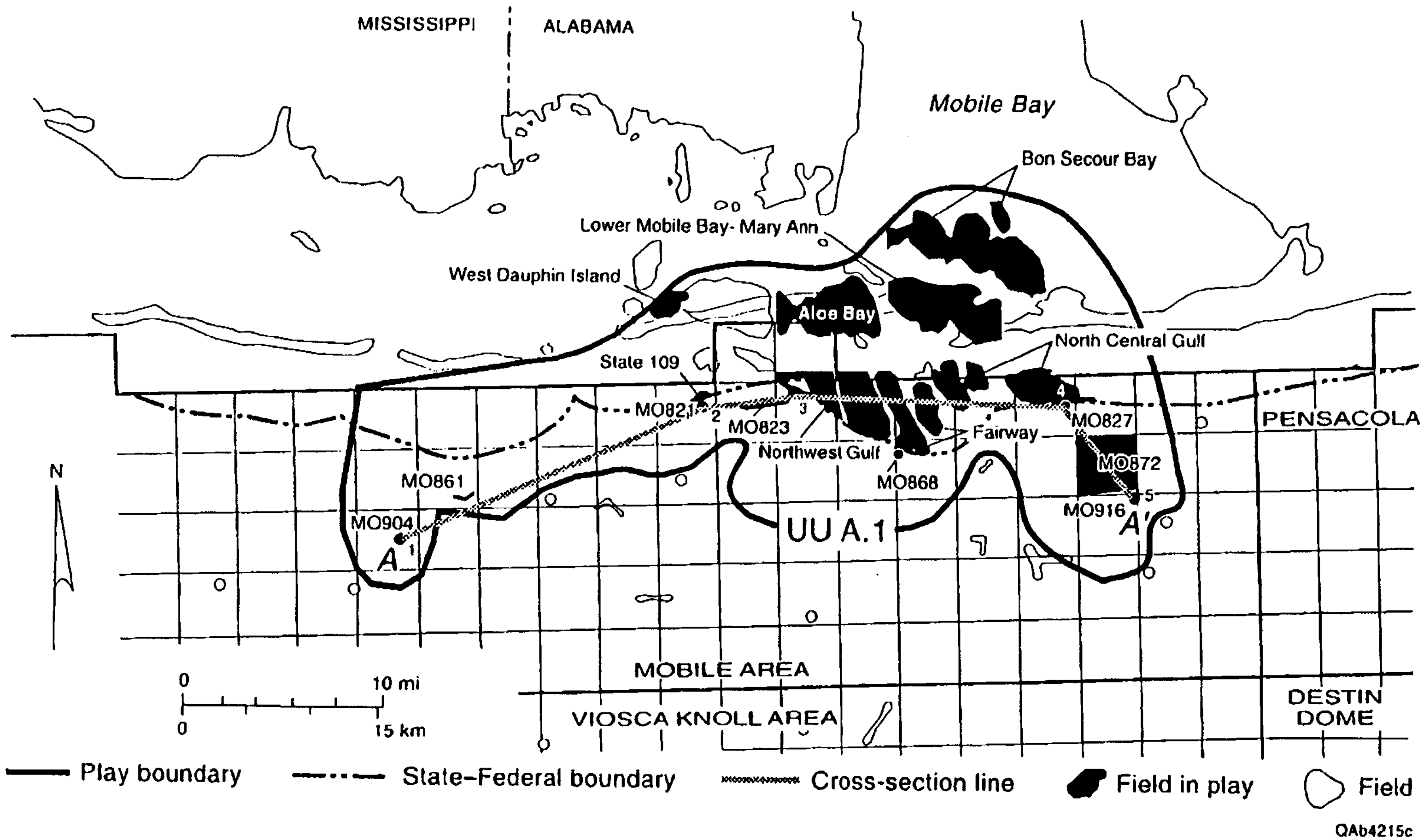


Figure 5.19. Norphlet Play Map.

Source: U.S. DOI, MMS, 1994.

6.0 Development Projects and Production History

Exxon describes Norphlet gas development as an integrated system involving specialized technologies for production, spur lines, and processing. Over $4.0 billion has been spent since the early 1980s installing these systems and drilling wells in addition to the $1.4 billion in bonus payments to acquire the leases. MOEPSI, Exxon, and Shell located sour gas processing plants onshore Mobile County. BP, first, and subsequently Union and Chevron, decided to process sour Norphlet gas on the platform, shipping pipeline-quality gas on DIGS and saving the cost of special carbon steel spur lines to shore. Shell uniquely transports corrosive wet gas to shore for dehydration and processing at the Yellowhammer Plant, relying on a proprietary corrosion inhibitor compound Shell developed in lieu of water separation on the platform.

This section describes the innovative approaches and technologies the companies applied to develop their Norphlet discoveries. Sections 6.1 - 6.4 discuss MOEPSI, Exxon, Shell and Union/Chevron. Section 6.5 tabulates facilities in place, summarizes production through 1997 and projects annual production into the future in relation to remaining recoverable reserves by field.

6.1 Development and Production of Mary Ann Field[95]

MOEPSI filed a formal Mary Ann Field development plan in September 1984, having already received a permit to construct a gas plant in South Mobile County, near Coden, to process the hot, sour, high pressure, corrosive Mary Ann Field gas. Design, development, and production was a challenge every bit as herculean as the environmental hurdles of the 1970s. Many aspects of the project required new technology or new applications of existing technology. Mobil repeatedly put the total cost of exploration and development of the Mary Ann Field at more than $400 million through start-up in 1988. Subsequent expansions and successes in the federal 823 and 869 Fields have raised Mobil's expenditures in Coastal Alabama to substantially more than $1.0 billion. OGJ[96] reported the following 1984 cost estimate for the Mary Ann Development:

[95]This section draws extensively from two articles:

J. R. Moseley, MOEPSI, "Mary Ann field facilities reflect Mobile Bay demands, conditions," OGJ, May 8, 1989, p. 36;

Richard A. Alexander, MOEPSI, "Environmental Method Controls Corrosion/Cracking in Mobile Bay," JPT, January 1990, p. 62 - 66.

[96]OGJ, "First development, gas strike listed off Alabama," September 24, 1984, p. 44.

Mary Ann Field Development	Millions
Well Drilling & Completion	$ 204
Platforms	122
Pipelines	31
Gas Plant	72
Total	**$ 429**

6.1.1 Safety and Environmental Considerations

The location issues alone, given the H_2S content of the Mary Ann Field gas, were overwhelming. The field is adjacent to resort, tourist and historic attractions. Laying between Fort Morgan on the Gulf Shores peninsula and Fort Gaines on Dauphin Island, Mary Ann Field is the site of Admiral Farragut's good fortune with those "damn . . . torpedoes" in 1864. Sunken ships from that battle and "literally thousands of cannonballs and other battle debris remain scattered across the bay."[97] The shipping fairway passes through the Mary Ann Field and serves traffic to Mobile, the 12th largest port in the United States. Mobile Bay's prized oyster grounds are just a few miles northwest of tract 76. The Mary Ann Gas Plant is four miles from the town of Coden and within two miles of unique, world famous Bellingrath Home and Gardens, which receives about 175,000 visitors a year.

A state-of-the-art environmental monitoring and warning system was installed to provide protection for the Mary Ann facilities and surrounding community. Six air monitoring stations were installed around the plant, on Dauphin Island and on the Fort Morgan Peninsula. Thirty-two H_2S sensors within the plant and 53 sensors on the offshore platforms detect H_2S and warn operating personnel.

6.1.2 Special Materials to Handle Norphlet Gas

Production of the Norphlet gas required new methods to deal with the unusual gas. The gas contains all the ingredients necessary for severe metal-loss corrosion—H_2S and CO_2 at relatively high pressures in contact with free water. All facilities had to be designed for 40-year life with zero risk of catastrophic failure. All of the platform's sour-process piping and vessels are made of carbon steel lined with corrosion-resistant alloy (CRA) tubing. Hastelloy C-276 was selected after 12 months of extensive testing as the CRA. This cold-worked, extremely tough alloy is recognized for its resistance to sulfide cracking and corrosion and its high temperature rating; but it costs as much as ten times the cost of ordinary steel tubing used in standard wells. The well stream from each wellhead is injected with corrosion inhibitor oil (CIO) to protect the surface equipment.

The Mary Ann Field development began with two platforms built by McDermott in Morgan City, LA, (76A and 77B), each designed for two wells producing 15 - 20 MMCFD, and one auxiliary platform (76Aux), designed as a central gathering platform bridge-connected to 76A. Platform 95E designed for 60 MMCFD was installed in 1988. Each well stream is cooled from

[97]"Damn the torpedoes. Full speed ahead," Shell article, undated.

temperatures over 230° F to 120° F on the platforms. Produced gas is dehydrated on the 76A, 77B and 95E platforms and dry, sour gas is pipelined ashore. Produced water and corrosion inhibitor oil (CIO) are pipelined to the plant for water disposal and reconditioning of CIO.

Completion of the first two production wells, 94-2 and 77-1, began in June 1986. Production was initially anticipated before year-end 1986. Leaks and problems ensued, however. A decision was made that the wells could not be safely produced without installing new casing liners because of corrosion. Four existing wells were reworked. First production did not flow until nearly two years later on April 5, 1988, from 77-2 at 15 MMCFD; 77-1 was brought on-line April 9, at 14 MMCFD.

Processing on the platforms worked well for about a month, when pressure drops were encountered across the 77-2 and 77-1 production cooler. Expecting a sulfur clogging problem, the system was shut down. Minute volumes of "a white powder was discovered which was analyzed as a rare hydrocarbon called diamonoid. This substance had been found in 1983 in Canada's Hanlan Swan Hills Gas Field. . . . [Experimentation revealed] that modifications . . . of the CIO . . . and piping modifications avoided the contamination."[98] Diamonoids, produced under heat and pressure from carbon, are a relative to the solid, hard mineral substance found in jewelry. MOEPSI found the "diamond as big as the Ritz" just a few million years too soon.

The fourth well, 76-2, brought field production up to 40 MMCFD sour gas in mid-July 1988. This well produced for two months and was shut in; it has never produced again. Production dropped back to 30 MMCFD by the fall of 1988. A year later Mary Ann was still producing three wells below 50 percent of design capacity—40 MMCFD of sour gas, yielding about 35 MMCFD of pipeline quality gas. Weak demand caused Mobil to delay installation of production equipment on its platform at the 95E location, which was brought on line in the summer 1989. Well 95-1 had a casing problem and was never produced. Two of MOEPSI's completed six wells, thus, developed mechanical problems, which caused them to be P&A'd. MOEPSI was the first to discover that maintaining production from $30 million Norphlet production wells is difficult.

6.1.3 Pipelines Used Special Techniques

The offshore facilities are connected to the onshore gas plant by five pipelines:

- 16-in. sour-gas pipeline;
- 6-in. bidirectional fuel-gas pipeline;
- 8-in. regenerated (CIO) to offshore pipeline;
- 6-in. CIO/produced water to the plant pipeline;
- 10-in. spare pipeline.

[98] J. R. Moseley, III, MOEPSI, "Lower Mobile Bay - Mary Ann Field Development," undated paper made available by Mobil.

The network is about 14 miles long, 10 miles offshore. The pipeline was buried deep under the ship channel by a boring technique instead of simple trenching to avoid any problems with shipping traffic. The boring technique was used to bring the pipeline ashore to avoid future problems with a deteriorating shoreline and at the Fowl River to avoid any intrusion with the bottom of the river. Oyster beds were carefully avoided. The rest was trenched

McDermott's Marine Construction Division began work in October 1985 and finished laying the pipelines in July 1986. Laying all five pipelines at once greatly reduced the risk of pipes crossing over each other, and being damaged, but required special equipment to inspect the welds on each pipe section. The logistics of getting all equipment and personnel on the laybarge was the first obstacle. Protecting the workers from substantial X-ray exposure while inspecting welds was a major challenge. Storing all waste water on board to achieve zero discharge was another challenge. Gutters were built around the barge so that rainwater would not flow over the barge into the Bay.[99]

6.1.4 Norphlet H_2S Variability and Mary Ann Gas Plant

Sulfur variability is a fact in the Norphlet fields. Not only does the H_2S content vary widely among the different dune structures of the Norphlet formation, it varies within fields and within tracts. Producing wells in the Mary Ann Field vary from 3.2 percent H_2S to 7.6 percent as shown on Table 6.1. The two wells in tract 77 range from 3.5 percent to 5.9 percent. The newest well in production in the Mary Ann Field, 95-5, is only 40 ppm H_2S while the forthcoming Aloe Bay gas is over 8 percent H_2S. H_2S in the 823 Field is less than 200 ppm in wells A1 - A3, but 2.3 percent in A4.

Table 6.1
H_2S Content of Producing Mary Ann Field Wells

Well	76-1	77-1	77-2	94-2	95-3	95-5
% H_2S	6-7%	3.5-5%	5.9%	7.6%	3.2-3.5%	0.004%

Source: Alabama Oil and Gas Board, 1997.

The original Mary Ann Gas Plant was sized to process about 80 MMCFD sour gas containing 7.5 percent (avg) H_2S and 4.5 percent CO_2, and produce 72 MMCFD pipeline quality gas with 225 long tons a day of liquid sulfur. The gas plant removes the sulfur, CO_2 and water. CIO is recaptured and regenerated for return to the wells.

6.1.5 Mary Ann Sales and Transport Problems

At the time of the 1979 discovery, the price of deep gas was about $4.00 MCF and expectations were that prices would rise to $7.00 MCF with the deep gas provisions of NGPA. Decontrolled

[99]Pipeline and Gas Journal, "Specialized Techniques Developed," March, 1987, p. 38 - 40.

section 107 gas actually sold for more than $10 MCF for a brief period. MOEPSI made the decision to develop in third quarter 1984 when U.S. gas prices averaged $2.62. When production started in April 1988, average U.S. gas prices were about $1.40 at the wellhead. Having invested more than 20 years and $400 million, the Mary Ann project was uneconomic when it started production based on then current prices, according to Executive VP, Paul J. Hoenmans.[100]

Mobil had difficulty finding a firm market for its Mary Ann production. Having surmounted the regulatory challenges of the 1970s and the technical challenges to develop and produce the Norphlet gas, finding a market became yet another challenge. When ANR Pipeline Co. said it could not take Mary Ann gas as scheduled, Mobil cancelled a contract with ANR in mid-1986. Transcontinental Gas Pipe Line Corp (Transco) later that year agreed to buy the gas for resale to Alabama Gas Corp in Birmingham. Algasco agreed to buy 18 BCF per year (50 MMCFD pipeline quality gas, or 58 MMCFD sour Mary Ann Field gas) for 15 years based on a formula that indexed to the price of alternate supplies. Transco built a lateral intrastate pipeline from the Coden plant north to connect to their trunk line at Butler, Alabama. Mobil received $2.15 MCF for its production, a premium of $0.60 above current spot, from Transco.

6.1.6 Mobil Mary Ann Field Production Profile

Production from the Mary Ann Field began in April 1988 but only climbed to plant design limits after wells 76-1 and 95-3 came online in January and November 1990. Well 95-4 was drilled and logged in May 1991, but never produced. Records show it temporality abandoned. Although eight wells have been completed, the Mary Ann Field original reservoir produces from five wells. Figure 6.1 shows the Mary Ann Field production profile through 1997. Aloe Bay 75-1 is included after July, 1997. Field production climbed from below 40 MMCFD in January 1990 to 80 MMCFD in February 1991. Mobil achieved planned utilization of original facilities during 1991 as well 95-3 was ramped up. Well 95-3 is the original Mary Ann Field's best well producing as much as 35 MMCFD during 1996, with lower than field average H_2S, 3.5 percent. Field production has varied between 50 MMCFD and 100 MMCFD over 1994 - 1996. Various technical problems—ranging from power outages to amine foaming problems—plus some self-curtailment to limit production when prices are low and maximize production when prices and seasonal demand are high explain the monthly variability in field production.

Mobil's newest well in the Mary Ann Field, 95-5, came on line during November 1996 producing 66 MMCFD during 20 days of November and averaging 71 MMCFD during December and January. Field production topped 160 MMCFD in December,1996, January and February, 1997. With 40 ppm H_2S, the 95-5 gas is in a different reservoir than the rest of Mary Ann production. This was the first of a new generation of Norphlet wells producing twice the average of the 823 Field wells, three to six fold as much as older Mary Ann Field wells, and more than any of Exxon's then-producing or Shell's wells. Enhanced 3D seismic capability to find the "best" place in the reservoir to produce, plus larger diameter pipes are key elements to the extremely high production rate of well 95-5. Mobil's first well into the reservoir was judged capable of producing about 50 MMCFD; they sidetracked the well and averaged 70 MMCFD

[100]OGJ, "Mobil steps up Norphlet gas flow off Alabama," July 18, 1988, p.18.

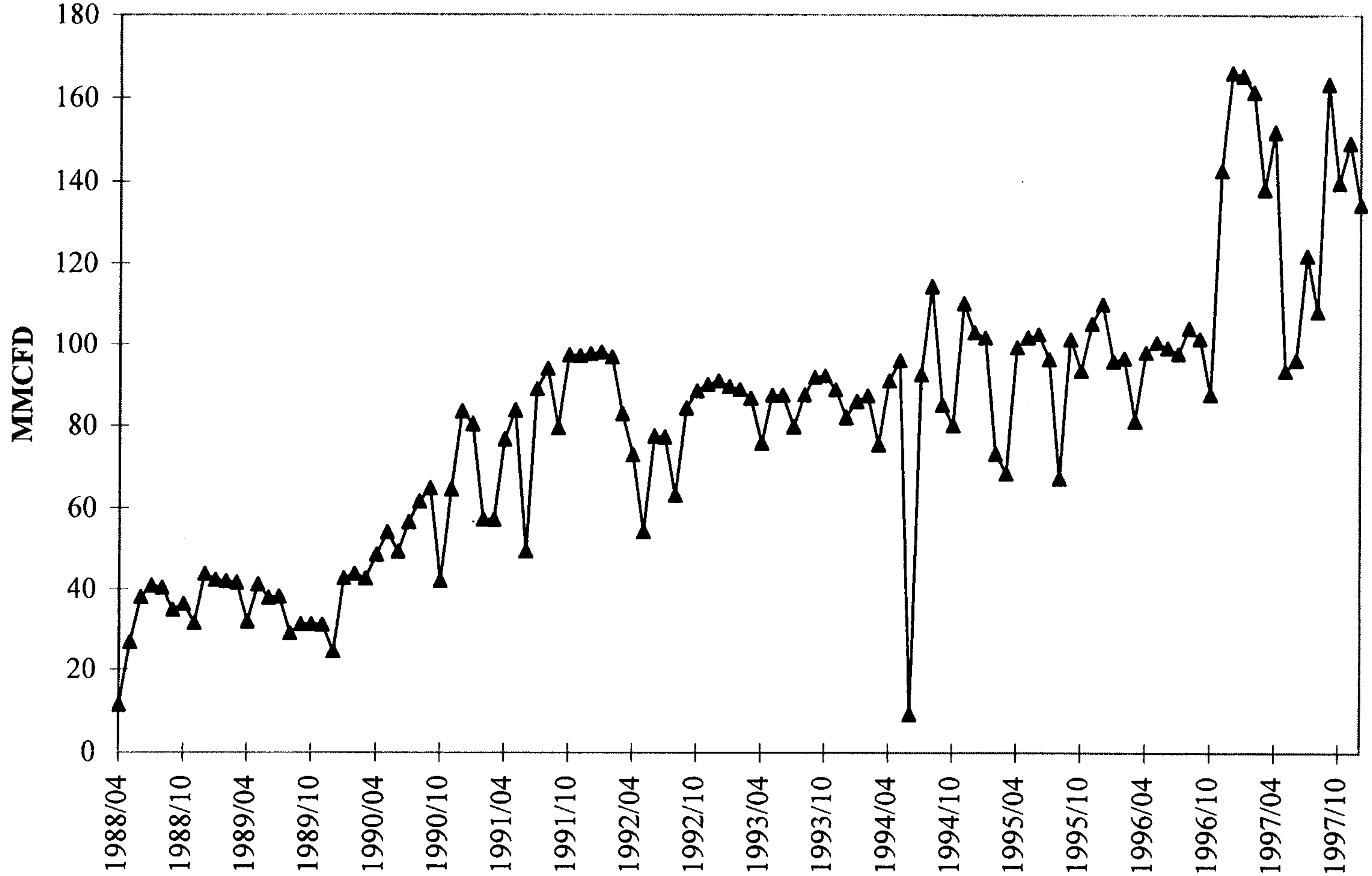


Figure 6.1. Mary Ann and Aloe Bay Fields Gas Production per Day.

Source: AOGB, 1998.

during November and December 1996. The well is drilled with a 30° angle, but not horizontally completed. The well is considered a "world offshore cementing record [for] using foamed cement on a 9 5/8-in. drilling liner."[101] The well technology plus the zero-discharge operating requirements were special challenges to completing the well. Keeping up production from the new well is also a problem. The well is on the edge of reservoir and close to water contact. Produced water and related scaling has become a problem. Production has declined from the high start-up rates to average 42 MMCFD during the fourth quarter, 1997. The well shut down for workover in April 1998.

Table 6.2 shows Mobil Mary Ann Gas Plant 1996 total intake, intake by well, gas sales and sulfur production. About 70 percent of the 95-3 gas production goes to the Mary Ann Plant. The balance is routed to Shell's gas plant to make room in the Mary Ann Plant for gas from Mobil's federal field well 823-A4, which came in with H_2S too high to process in the 823 plant. Mobil doubled its capacity of the Mary Ann plant to 160 MMCFD to take in the unexpectedly sour gas from 823-A4 well. That well tested 68 MMCFD with 2.8 percent H_2S from 22,570 feet on December 11, 1990. The high H_2S was a surprise; production was not started until March 1994, after the Mary Ann Plant sulfur handling capacity was increased. The low H_2S 95-5 gas goes to the 823 Plant.

6.1.7 Aloe Bay Field and Mary Ann Plant Expansion

The 8 percent H_2S Aloe Bay well 75-1 was brought online at 10 MMCFD in July, 1997. Design production is between 30 - 50 MMCFD; the well averaged 24 MMCFD during the fourth quarter, 1997. The Aloe Bay Field is producing from a single platform just north of Dauphin Island. A three pipeline bundle transports gas and utilities between the tract 75 platform and the existing 76A platform in the Mary Ann Field for processing in the Mary Ann Plant. During the first quarter 1997, the Mary Ann plant averaged 141 MMCFD. Debottlenecking in early 1997 increased the sulfur recovery capacity of the Mary Ann Plant from 285 LTD to 470 LTD to handle the Aloe Bay well and give the plant capacity for 180 MMCFD high sulfur gas. Production declines, well problems and warm 1997-1998 winter conditions have not tested the capacity limits of the Mary Ann Plant since Aloe Bay was added to production, as can be seen on Figure 6.1 and Table 6.2. Mobil is considering adding a second Aloe Bay well, 75-2, during 1998.

The Aloe Bay pipeline bundle is bored deep beneath the northwest trending section of Little Dauphin Island between tracts 75 and 76 to avoid oyster beds and other sensitive environmental areas.[102] The route is shown on Figure 6.2.

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[101]Glen Benge, Jim McDermott, Joey Langlinais, and James Griffith, "Foamed cement job successful in deep HTHP offshore well," OGJ, March 11, 1996, p. 58 - 63.

[102]Army Corps of Engineers, "Joint Public Notice: Emplacement of Pipeline System, Mobile Blocks 75 and 76, Aloe and Mobile Bays," October 28 1996.

Table 6.2
Mobil Mary Ann Plant Gas Per Day 1/96 - 12/97
MMCFD

	Total gas	Wells								Gain thr. Plant	Sales	Sulfur Production Long tons
		76-1	77-1	77-2	94-2	95-3	95-5	823-A4	Aloe Bay 75			
Jan 96	147.230	12.025	10.243	23.685	12.115	26.923	0.000	62.239			132.190	232.510
Feb	148.263	13.923	11.770	24.691	13.984	23.737	0.000	60.158			133.303	245.200
March	121.440	9.682	8.830	19.902	10.824	21.909	0.000	50.294			109.123	219.232
April	145.228	13.191	11.245	25.212	13.076	25.432	0.000	57.073			131.596	252.703
May	147.448	12.947	11.563	26.170	13.720	25.439	0.000	57.610			132.902	262.949
June	151.415	12.758	11.353	25.429	12.996	25.319	0.000	63.571			137.280	246.742
July	148.565	13.689	11.702	24.946	13.070	22.912	0.000	62.245			134.917	259.189
August	151.396	13.838	12.097	25.327	13.889	24.685	0.000	61.560			137.032	261.932
Sept.	151.926	13.435	12.781	26.222	13.581	25.242	0.000	60.664			137.826	260.424
Oct.	128.140	11.261	10.902	23.625	11.130	23.365	0.000	47.856			114.486	213.881
Nov.	142.864	14.597	13.248	28.777	14.998	13.870	0.119	57.254			127.480	220.206
Dec	138.311	13.189	12.777	27.778	13.916	14.742	0.213	55.696			125.283	279.793
Jan 97	136.253	14.584	12.852	27.736	14.031	14.967	0.201	51.884			124.166	249.545
Feb.	155.038	16.190	13.678	29.744	14.875	16.656	0.160	63.735			141.802	276.423
Mar	140.034	14.624	12.354	26.865	13.436	15.044	0.145	57.567			128.079	249.672
April	132.284	14.637	11.930	26.148	11.479	11.372	0.233	56.486			119.599	228.504
May	67.098	7.712	6.973	15.211	4.077	1.182	0.148	30.529		1.265	60.099	124.613
June	20.812	3.109	3.277	6.444	2.061	3.474	0.148	2.299		0.000	17.126	0.684
July	66.566	10.303	9.615	18.447	10.042	0.017	0.241	7.641	5.528	4.731	58.083	175.665
August	47.072	4.773	6.458	13.027	4.361	4.162	0.133	3.434	9.518	1.207	39.058	104.140
Sept.	139.614	12.218	12.828	23.849	11.815	4.838	0.090	45.812	27.257	0.000	127.765	242.282
Oct.	137.782	11.291	10.485	21.256	10.948	9.696	0.071	47.953	25.419	0.662	126.112	269.833
Nov.	134.468	11.186	11.012	22.808	11.523	5.025	0.130	47.775	24.197	0.000	121.682	260.461
Dec	122.669	9.725	10.297	21.230	10.472	10.776	0.105	39.151	20.912	0.000	110.459	253.097

Source: Alabama Oil and Gas Board, 1997.

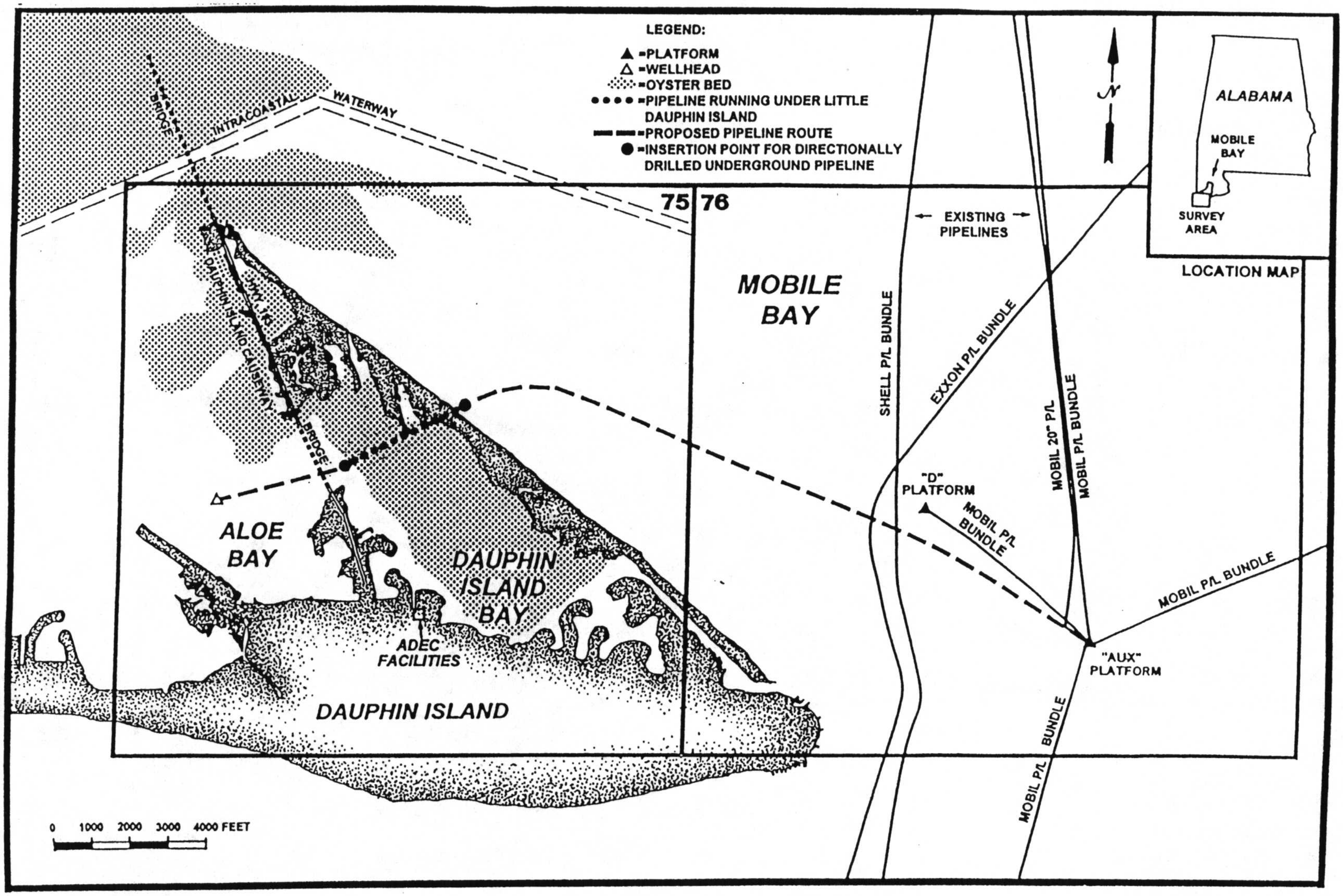

Figure 6.2. The Aloe Bay Pipeline Route.

Source: MOEPSI, "Environmental Information for a Pipeline Route Within Blocks 75 and 76 Mobile Bay Area, Alabama," August 28, 1996.

6.1.8 Federal 823 and 869 Fields

Mobil received MMS approval to construct the 823 platform and gas plant facilities in September 1989 as the first Norphlet development in federal waters. McDermott Marine Construction engineered, constructed and installed the platforms and facilities in Mobil's 823 Field. Platform 823A, a single well platform, went in mid-1991 at a cost of $41 million. The platform includes facilities for separation and dehydration of the gas. Production is separated and dehydrated for corrosion abatement on the platform.[103] The Mobile 823 Gas Plant facilities began construction in 1990 and were completed in the third quarter 1991.

Gas started flowing at 40 MMCFD from a single well in November 1991. Two more wells brought production to 160 MMCFD in March 1992 with less than 200 ppm H_2S.[104] At year end 1993, MOEPSI was producing 150 MMCFD from three wells in 823 to its 250 MMCFD capacity Mobile 823 plant.

A 20-inch gathering pipeline system was installed from the 823 processing Platform A to the Mary Ann Auxiliary Platform for delivery to the 823 onshore treatment plant. Planned with a 250 MMCFD capacity, construction was contracted in late 1989. A separate 8-inch line was required to deliver sour 823-A4 gas to the tract 76Aux Platform for delivery to the Mary Ann plant.

Mobil's most recent well started production from the 869 Field in late January 1997 at about 60 MMCFD. H_2S is about 90 ppm. The well produced 78 MMCFD in February, 85 MMCFD in March, and averaged 64 MMCFD during the fourth quarter, 1997. The gas is transported to the 823A platform and then to the 823 Plant for processing.

Figure 6.3 shows the 823 and 869 Fields' production history from the start-up of 823 in November 1991. Production averaged about 160 MMCFD from three 823 wells during most of 1992. Production from Well 823-A2 was shut down for most of 1993, bringing field production down to 100-120 MMCFD. The high H_2S well brought production above 190 MMCFD in the highest producing months of 1994. Production from the four wells varied between the 194 MMCFD peak and 170 MMCFD until late 1995, then dropped off in late 1996 as wells 823-A1 and 823-A2 declined from peak. Well 823-A5, spudded in December, 1997, will stave off decline. Mobil produced close to 250 MMCFD of federal gas in March 1997 after 869-3 came online. Production from the two federal field averaged 203 MMCFD during the fourth quarter, 1997. Mobil, acting with partners Enron and Chiefton, spudded well 914-4 in December, 1997, to the southeast of producing well 869-3 to add to production from this area.

Table 6.3 shows the 823 plant gas throughput. Beside the low H_2S 823 wells, the plant is taking Hunt's 25 percent share of Exxon's tract 114 production, plus most of the gas from 95-5 and gas from the 869 Field. The plant capacity has been debottlenecked to 300 MMCFD. In January 1997 the plant received 193 MMCFD and sold 189 MMCFD. In February, March, and

[103]OGJ, "Norphlet gas development set in federal water," October 9, 1989, p. 24.

[104]OGJ, "Gas flowing from field off Alabama," November 11, 1991, p. 27.

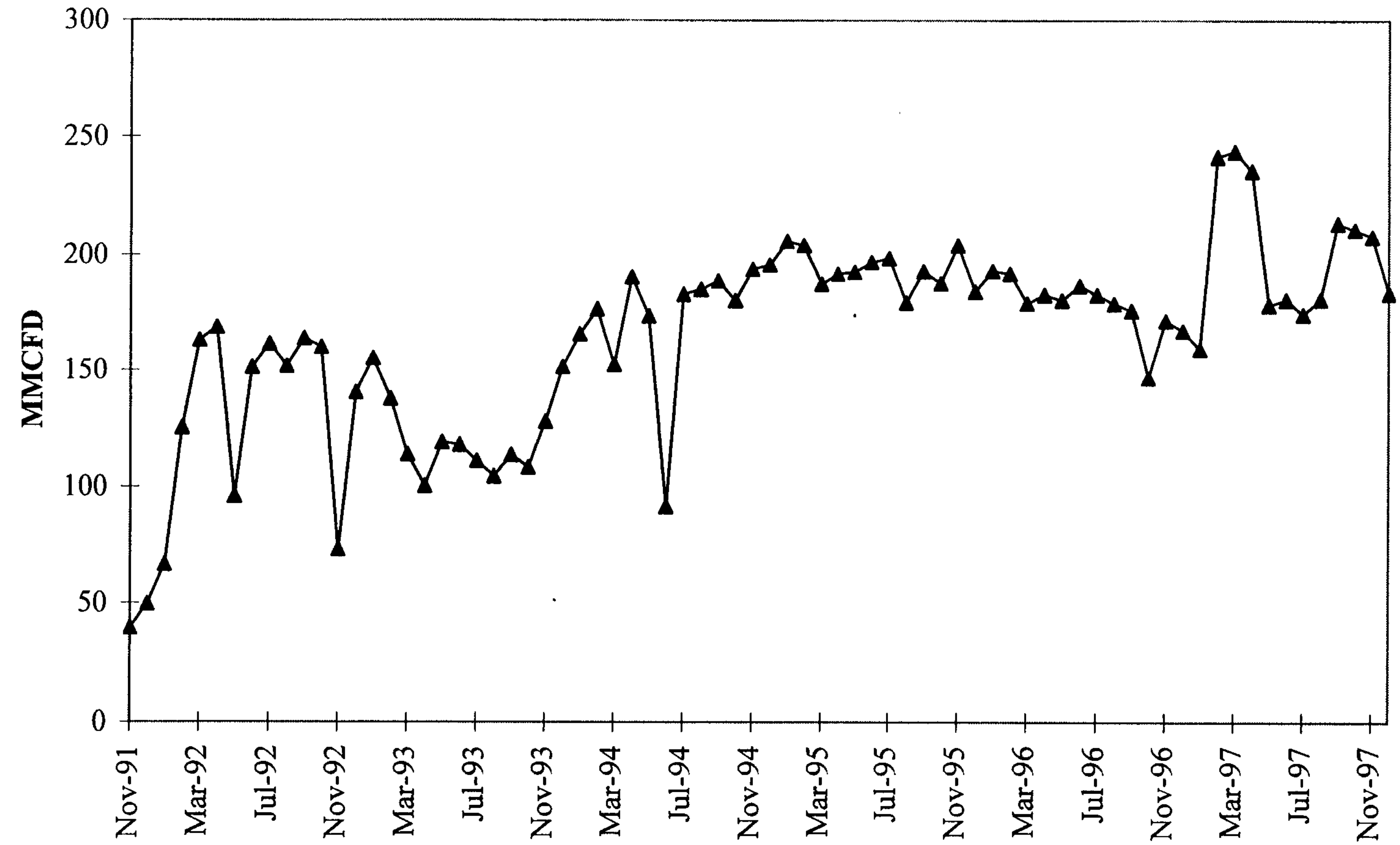

Figure 6.3. Mobile 823 and 869 Fields Norphlet Production.

Source: Dwights/PI, 1998; Foster Associates, Inc., 1998.

Table 6.3
Mobil 823 Plant Gas Per Day 1/96 - 12/97
MMCFD

		Lease		Hunt 25% Share			Sulfur Production Long tons
	Total Gas	**95-5**	**823-A1, 2, 3**	**114**	**869-3**	**Sales**	
Jan 96	163.554		147.914	15.640		160.130	
Feb	167.972		152.037	15.935		164.350	
March	165.805		149.372	16.434		161.643	
April	170.585		150.183	20.402		167.150	
May	167.954		147.515	20.439		164.395	
June	168.796		148.115	20.682		165.274	
July	162.448		143.564	18.884		161.707	
August	146.477		133.985	12.491		142.778	
Sept.	144.617		131.948	12.669		141.181	
Oct.	121.813		111.934	9.879		119.123	
Nov	175.821	44.115	118.746	12.961		171.351	0.399
Dec	200.171	71.956	83.624	12.333		194.506	0.304
Jan 97	192.813	69.378	110.390	12.044	1.001	189.931	0.318
Feb	269.047	67.335	112.229	11.740	77.743	265.561	3.736
Mar	247.731	44.396	107.011	10.928	85.396	244.221	2.117
April	258.844	61.635	105.084	12.079	80.046	254.693	3.432
May	202.552	40.918	85.028	9.286	67.321	200.083	1.868
June	252.890	58.273	108.006	11.671	74.940	244.880	3.105
July	227.874	46.692	105.079	10.045	66.058	218.032	7.271
August	236.206	42.649	111.347	11.570	70.640	230.037	7.553
Sept.	230.271	49.061	101.351	11.637	68.222	225.252	1.692
Oct.	211.977	38.425	95.903	10.411	67.238	207.936	2.579
Nov	219.163	47.805	95.473	11.029	64.856	213.023	2.796
Dec	191.123	39.630	83.687	7.194	60.613	186.645	5.151

Source: Alabama Oil and Gas Board, 1997; US DOI, MMS, 1998.

April, with 869-3 hitting 78 - 85 MMCFD, the plant processed 247 - 269 MMCFD, the high for 1997.

6.1.9 Mobil Production Summary: 1997

Mobil's Aloe Bay and Mary Ann fourth quarter, 1997, average production, 134 MMCFD, was well below the spring peak. The 823 and 869-3 wells fourth quarter average production averaged 203 MMCFD. Combined, Mobil produced 337 MMCFD at the end of 1997, about 70 percent of their plant processing capacity.

6.2 Development and Production of Exxon Project[105]

With discoveries in Bon Secour Bay (BSB), North Central Gulf (NCG), and Northwestern Gulf (NWG) state fields, plus 827 and 867 federal fields, Exxon announced the second Mobile Bay project in October 1986 to develop its extensive leaseholds. OGJ subsequently reported that Exxon's discoveries in state waters amounted to 2.8 TCF.[106] Exxon hoped to produce as much as 600 MMCFD from its fields, according to the OGJ article. Exxon filed plans with the COE to install multiple production platform complexes in tracts 64, 112, 114, 827, 867 and 868. The platforms on state tracts 62, 63, 111, 112, 114 & 115, and the platform on OCS tract 827 are currently producing. The 868 reserves were developed by the Mobil-operated well 869-3, with Exxon a 30 percent partner. 867 is planned for development in 1998.[107] Exxon referred to a gas sales contract as one hurdle to overcome during the development process.[108] Exxon, like Mobil, was caught-up in the middle of the "gas bubble."

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[105]This section is based on five Exxon papers delivered at the May 1994 OTC.

Johnson, H. E., R. J. Kartzke, and R. M. Kruger, "The Mobile Bay Project," OTC 7447.

Gallagher, M.J., T. T. Arthur, D. E. Boening, and K. A. Sortland, "An Overview of the Mobile Bay Project Offshore Facilities and Installation Approach," OTC 7448.

Gordon, J.R., D.V. Johnson, S.R. Herman and J.B. Darby, "Well Design and Equipment Installation for Mobile Bay Completions," OTC 7571.

Arthur, T. T., E. L. Cook, and J.K Chow, "Installation of the Mobile Bay Offshore Pipeline Systems," OTC 7572.

Page, W. A., R. D. Teague, "Mobile Bay Project Quality Management Program," OTC 7449.

[106]OGJ, "Industry slates more exploration, development in gulf Norphlet trend," March 6, 1989, p. 15 - 18.

[107]Exxon note to William Wade, May 5, 1997.

[108]OGJ, "Development activity dots Mobile Bay trend," April 6, 1987, p. 27

6.2.1 Integrated Norphlet Production and Processing Facilities

Exxon described its Mobile Bay Project as the world's largest offshore sour gas development. Their reported costs included $1.0 billion for facilities to produce and process 400 MMCFD from its three state fields (including 827) plus nearly $600 million bonus payments and $30 million each to drill and complete each well.[109] *Offshore* magazine estimated the project cost at $2.0 billion for the 30 year project, including the bonus payments.[110] Exxon's project emphasizes that developing Norphlet gas requires an integrated system of field production facilities, processing plant and gathering lines designed specifically for the gas from specific fields.

Exxon's basic plan entailed development of its three state fields simultaneously, plus the federal 827 Field within the tract 115/116 development plan, and bringing the sour gas ashore for treatment at a single plant. Brown and Root designed the production facilities and flow lines. Fluor-Daniel designed the gathering system. H. B. Zachry, San Antonio, designed the onshore treating plant, with Stearns-Roger, Denver, subcontractor for plant construction.[111]

The offshore work was done under rigid environmental stipulations that required all discharges to be collected and barged for onshore disposal. Siltation was avoided to protect nearby oyster beds. Production of sour gas from hot, high pressure reservoirs required exceedingly high standards of equipment integrity and reliability. Risks associated with the sour gas, and high cost wells and facilities, made quality of products used a high priority.

Like MOEPSI, Exxon's project had to deal with H_2S that varied greatly among tracts and even among wells in different dunes within tracts as shown on Table 6.4. H_2S on tract 111 varies by a factor of 300-fold between wells. (100 ppm equals 0.01 percent.) Tract 62 gas is nearly 10 percent H_2S—1000 times greater than well 112-2 H_2S.

Table 6.4
H_2S Content of Exxon's Wells

Well	111-1	111-2	112-1	112-2	114-2	115-1	116-1	62-1	63-1	78-1	827-1
H_2S	100 ppm	3%	.2%	100 ppm	.3%	100 ppm	120 ppm	9.7%	1.5%	1.4%	90 ppm

Source: Alabama Oil and Gas Board, 1997.

The onshore gas plant was originally designed to treat a mix of gas containing 95 percent hydrocarbon, 4 percent CO_2 and the range of H_2S content gas shown on Table 6.4.[112] The varying compositions in the produced sour gas led to a plant design that incorporated two sulfur

[109] OGJ, "Mobile Bay gas flow rising in response to E&D campaigns," Jan 10, 1994, p. 22.

[110] Offshore, "Exxon USA's massive Mobile Bay Project getting underway," October, 1991, p. 34.

[111] OGJ, "Exxon to develop gas reserves off Alabama," September 24, 1990, p. 46.

[112] OGJ, "Exxon to develop gas reserves off Alabama," September 24, 1990, p. 46.

trains, one initially designed to handle 110 long tons (LT) sulfur per day and the other 40 LT sulfur per day, and required what Exxon described as a unique air-emissions permit.[113] The plant was designed for 300 MMCFD, but with minor modifications was debottlenecked in 1994 to process 400 MMCFD. Subsequent sulfur plant modifications to pumps and valves have enabled Exxon to take in gas with higher average H_2S content. Capacity remains rated at 400 MMCFD, with a higher average sulfur content producing as much as 228 LT of sulfur per day in early 1997. By winter 1997 Exxon could extract 285 LT of sulfur per day.

Figure 6.4 shows that eleven wells on Exxon's three state fields and federal 827 Field are produced to Exxon's onshore treating facility. Besides the varying H_2S content, all of the gas has high pressure (Initial bottom hole pressures were 10,500 to 13,500 psi.) and high temperature (as high as 385 - 420° F). Production from the NCG Field flows to the NWG Field and then to shore. BSB gas is added to the 24 inch-pipeline that takes the combined gas to shore.

Each field has a production platform that separates and dehydrates gas on the platform. Separation sends a dry sour-gas stream and a liquids (mostly water) stream ashore for processing. Solid corrosion resistant nickel alloy (CRA) is used in all the flowlines to withstand the pressure, temperature and corrosive nature of the gas. To absorb diamonoids and prevent plugging, fresh diesel is injected into well streams, if needed. All wells were completed with 3.5 and 4-inch CRA tubing. Four early exploration wells with steel production casing at total depth were retrofit with the CRA liners. Different classes of CRA were used in the wells dependent on the H_2S, bottomhole pressure and temperature of the gas produced in the well. This saved the project substantial money while assuring safety and quality of materials.

Nearly 200 miles of high pressure alloy and carbon steel pipe is installed to connect the three production platforms and five well templates with the onshore treating facility. Like Mobil, a five line gathering system connects the onshore plant with the production platforms to transport diesel, fuel gas, produced gas produced liquids and dilution water. Water depths along the right-of-way range from 2 to 50 feet in both the protected inshore Mobile Bay waters and the high current, open waters outside the Bay.

A separate 42-person living quarters is bridge-connected to the NWG production platform. This houses offshore personnel from all three fields. Each platform has a separate bridge-connected template for one or more producing wells. There are five remote well templates.

6.2.2 Project Management and Quality Control

Planning and management of the construction and installation of platforms, production equipment, and flowlines among three fields and an onshore treating plant simultaneously was yet another herculean milestone in the Norphlet story. Quality, supervision and inspection were planned for at the inception to assure that the project met program objectives:

- Assure that completed facilities met design, functional and regulatory requirements;

[113]OGJ, "New Mobile Bay complex exploits major sour gas reserve," May 23, 1994, p. 49 - 51.

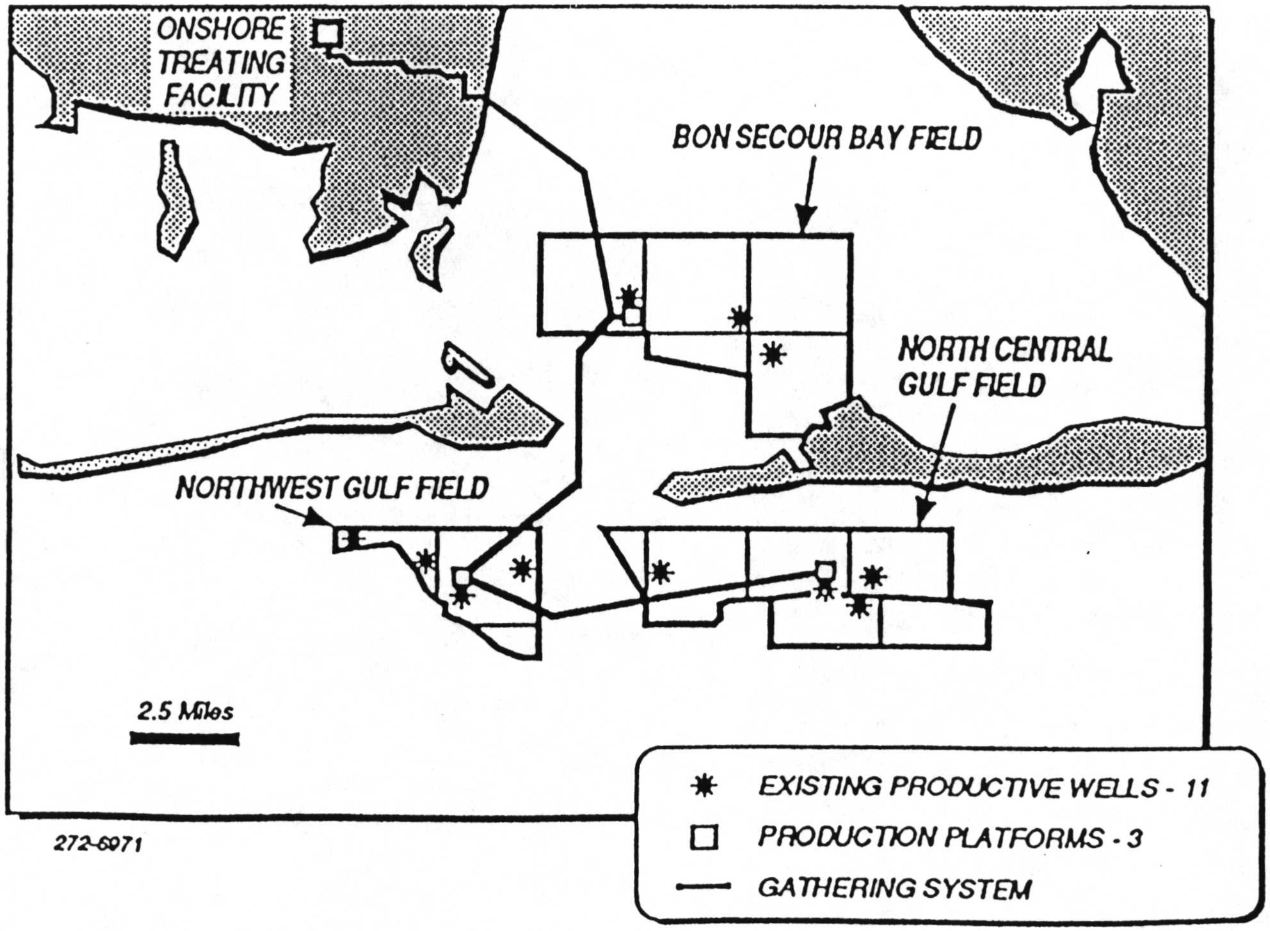


Figure 6.4. Mobile Bay Area.

Source: Exxon, 1997.

- Ensure timely documentation and compliance;
- Build in quality to virtually eliminate risk of failure.

A project management plan was implemented to assure quality by lines of responsibility, anticipated audits and inspections, and documentation. Eight thousand units of pipe, valves, fittings, and welds were inspected with only one reject found. Exxon designed critical components with zero tolerance for failure.

Exxon developed much new or untried technology. Cold-worked CRA was identified early as an optimum material for flowlines. A pipe-in-pipe insulated system was selected. This created a challenge for welding technology because cold-worked materials had not previously been considered candidates for welding applications. A welding procedure had to be developed that would produce high strength, repeatable welds in an offshore environment. Welders had to be trained to perform the welding with repeatable exactitude. At the initiation of the welding development program, Gas Tungsten Arc Welding (GTAW) took about seven hours to complete a weld. By the time field welding was to begin, this time had been reduced to 35 minutes. Full documentation of each weld including X-rays and interpretation by a small group of specialized personnel assured the integrity of the welding program.

Pipelines were installed during the summer months of 1991 and 1992. The BSB pipe bundle was installed in 80-foot joints in a common ditch using conventional lay methods. The 1992 workscope achieved the following:

- Offshore flowlines were installed;
- Nearshore gathering lines were installed;
- Offshore gathering lines were installed;
- Inshore gathering line from the tie-in at the east end of Dauphin Island to the beach approach was installed.

This entailed directionally drilled crossings, which required much coordination between pipe string layout, drilling and excavation contractors. Exxon specially constructed a laybarge to allow the installation of five pipelines in the bundle simultaneously.

Planning for the project started in early 1986. Wells were drilled between 1983 and 1993, with six final wells tested and completed in 1993. Offshore work was accomplished between 1991 and 1993 with 2.7 million contractor hours. Figure 6.5 shows the scheduling of the offshore work, exclusive of drilling, by month. The onshore plant work was completed during the same period. At one time Exxon had 2,000 contractors working with 200 Exxon people. Over 100 contractor firms were involved with various aspects of the work, with Exxon assuming an overall coordination role. The offshore pipelines team used 1.5 million of the entire 2.7 million-

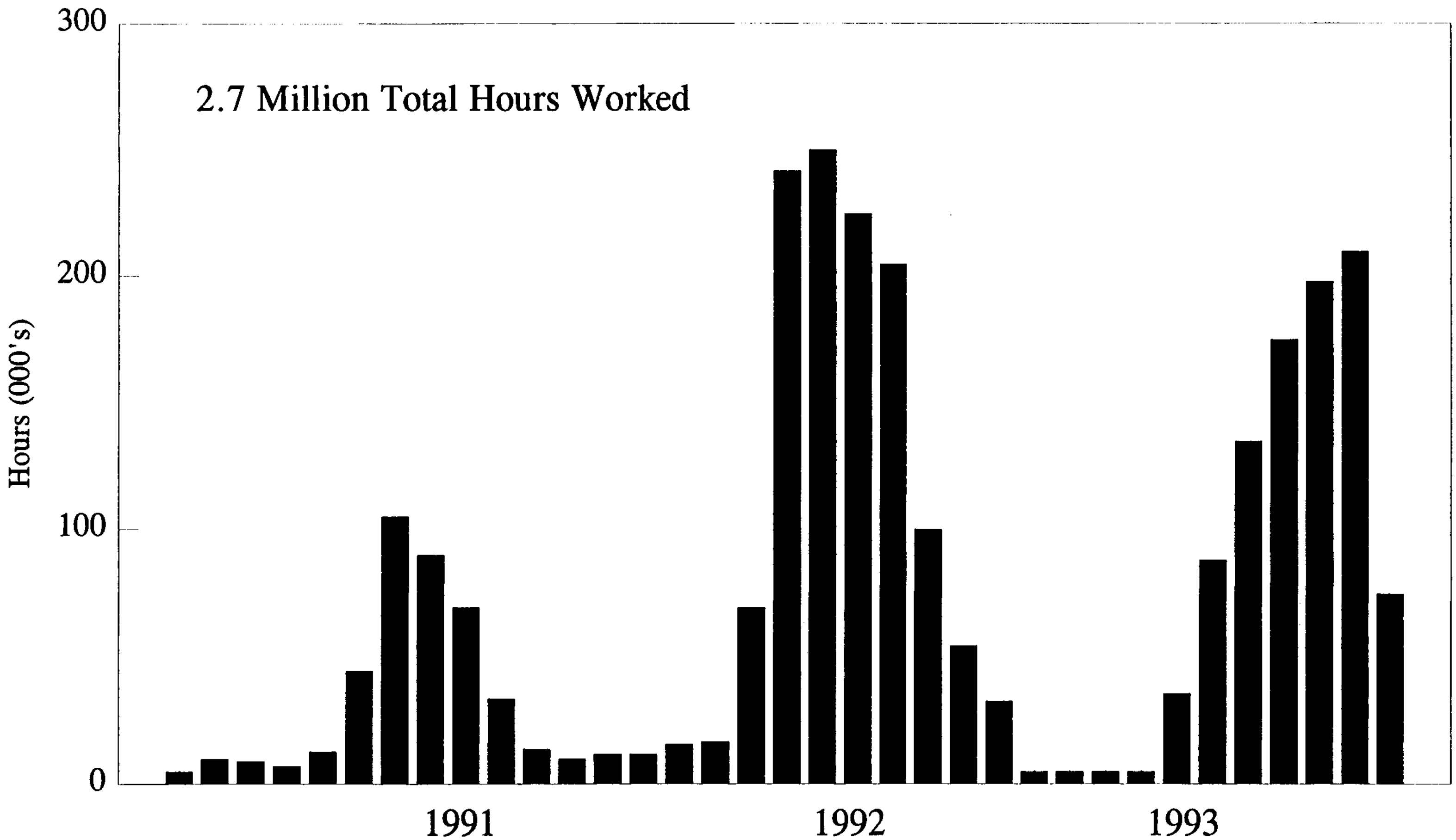


Figure 6.5. Exxon Project Contractor Hours Worked Offshore.

Source: Exxon, 1997.

hour project. There were no significant environmental incidents and no "lost time" safety incidents. The pipeline segment of the project came in 20 percent under budget.

6.2.3 Exxon Project Production Profile

Startup of the eleven wells in state and federal waters was completed over a 45-day period beginning with the Northwest Gulf Field in October 1993. Figures 6.6 - 6.8 show the monthly production rates from the three state fields, including production from 827-1 on Figure 6.6. By March 1994 Exxon was producing at the following rates:

Field	MMCFD
NCG	93
827	19
NWG	189
BSB	80
Total	**381**

The NCG/827 Field has maintained the nearly 120 MMCFD production rate with only occasional variation since start up. This gas is lower in H_2S than BSB. The spike in September 1994, common to all fields, reflects routine maintenance at the onshore treating facility. Exxon spudded well 114-3 in March, 1997, to offset Mobil's 95-5 well. Production started February 10, 1998, and ramped to 65 MMCFD March 5, 1998.

The NWG Field has had periodic production problems, illustrated by the shutdown of its 112-1 well on June 12, 1996; 112-1 is reported to have had mechanical problems. The well produced 42.3 MMCFD in January 1996—the high for the year. The well returned to service in September 1997. Well 112-2 was shut down in April 1997 for a workover to clean scaling and repair the SCSSV, which was completed in August 1997. Production in the field for the three months ending January 1997 averaged 105 MMCFD, about 55 percent of the average for the three months ending March 1994. Keeping Norphlet wells producing at design rates is a challenge. Exxon brought well 111-3 online in March 1997 at 77 MMCFD to supplement production. Exxon refers to its high initial production as "a typical NWG well with standard diameter tubing; processing capacity was available [for high production rate] and well facilities were designed for maximum initial rate."[114] Returning wells 112-1 and 112-2 to service brought field production back to 200 MMCFD in October.

BSB production increased from 40 MMCFD at start up to 120 MMCFD in December 1996. The same three wells have ramped up consistently since they came on line in November 1993. BSB wells were ramped up even further to maintain plant throughput and sales commitments after the 112-1 well was taken out of production in 1996 for a workover. BSB wells averaged 106 MMCFD during the fourth quarter, 1997. Mobil and Exxon are planning a joint well on

[114]Exxon note to William Wade, May 5, 1997.

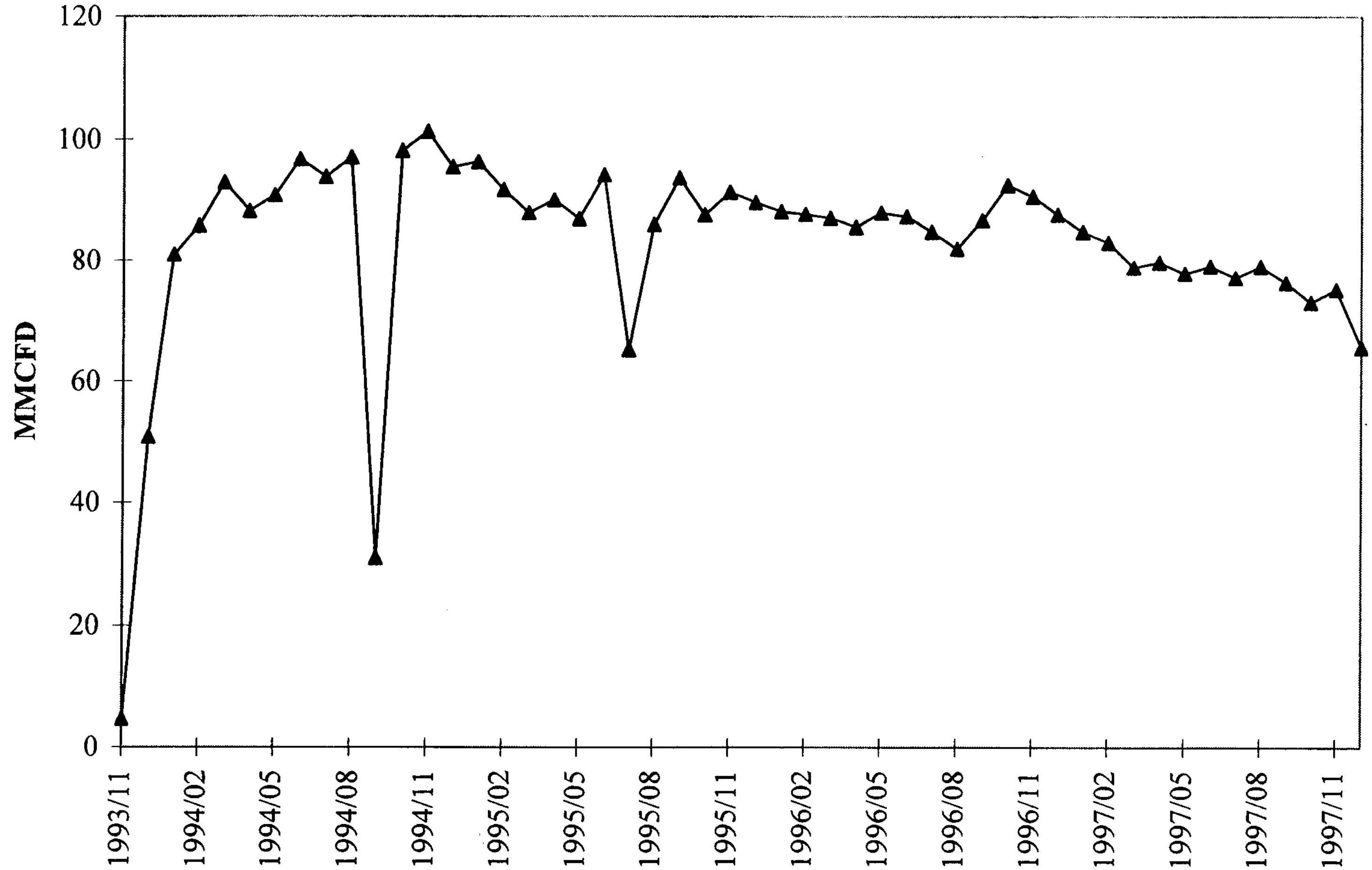


Figure 6.6. North Central Gulf/Mobile 827 Field Gas Production per Day.

Source: AOGB, 1998.

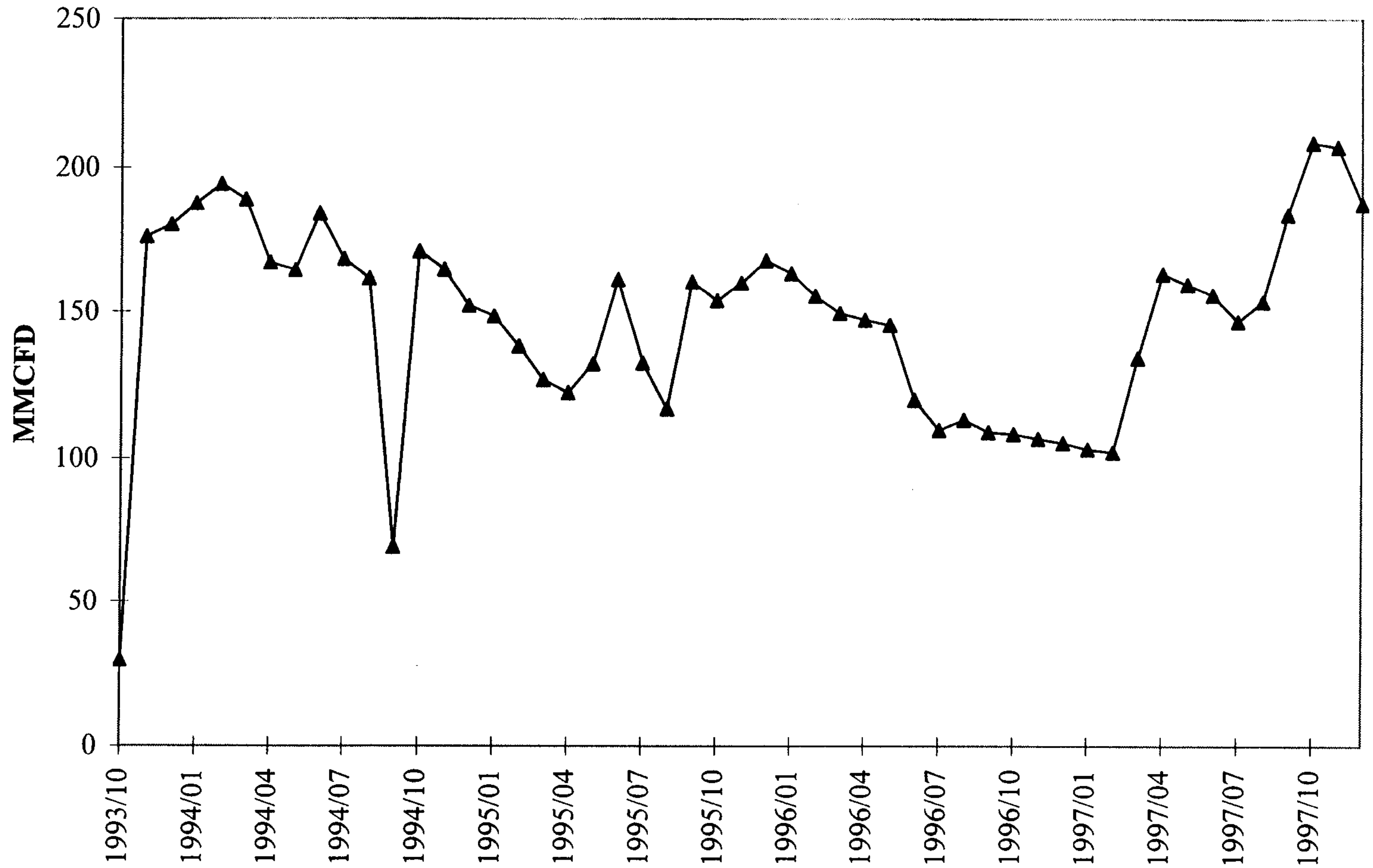


Figure 6.7. Northwest Gulf Field Gas Production per Day.

Source: AOGB, 1998.

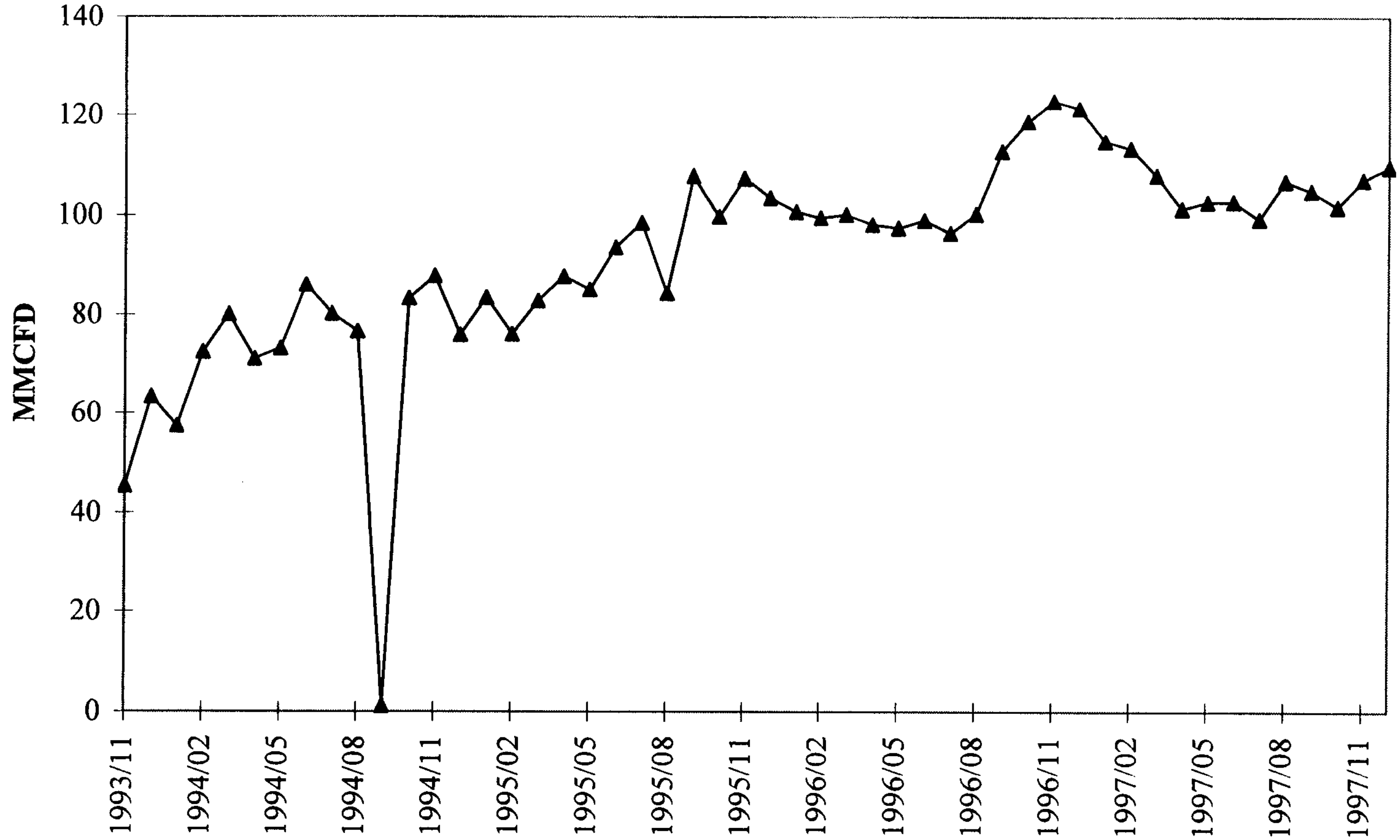


Figure 6.8. Bon Secour Bay Field Gas Production per Day.

Source: AOGB, 1998.

Mobil's tract 61 during 1998, which will add production from the BSB reservoir, and be processed in the Mary Ann Plant.

Table 6.5 shows the Exxon Gas Plant's 1996-1997 gas intake, intake by well, sales gas and sulfur production by month. This does not include the Hunt gas produced from NCG. Hunt, with 25 percent ownership of tract 114 within NCG, takes its gas in kind and processes the gas in Mobil's 823 plant. Sales gas declined from 94.5 percent to 93.9 percent of intake gas from January to December because of the much more sour BSB gas production that was increased to replace the lost production from NWG well 112-1. Sulfur production increased nearly 20 percent since mid-1996 when BSB production was lower. The Exxon plant is reported to be sulfur removal limited with the current mix of gas; the plant averaged 274 long tons per day during the fourth quarter, or 96 percent of its reported 285 lt sulfur capacity.

6.2.4 Exxon Production Summary: 1997

With Exxon's well 111-3 sustaining production over 70 MMCFD, Exxon's Gas Plant approached estimated capacity of 400 MMCFD at year end 1997. Well 114-3, producing near 65 MMCFD in April, 1998, pushed Exxon's production to 445 MMCFD, above plant capacity, even though the federal well 827-1 was shut in for balancing. Production from Exxon's 867 field, slated for 1998, clearly gives Exxon producibility exceeding plant capacity.

6.3 Development and Production of Shell's Fairway Field and Yellowhammer Project[115]

Shell Offshore Inc (Shell), having discovered gas on their $57 million state tracts 113 and 132, announced plans to develop the Fairway Field on November 8, 1989. Construction began in the first quarter 1990; the onshore plant and offshore production came on line December 5, 1991. Shell's Fairway Field was the second field brought into production. Natural gas was selling for $0.93 per MCF when Shell initiated production—about 10 percent of the industry's price outlook when Shell bid on the leases within the State's first lease sale ten years earlier.

6.3.1 Development Avoided Shipping Channel and Civil War Artifacts

With its May 1986 discovery well 113-1 confirmed by the late 1988 132-1 delineation well, and with time running on its lease, Shell filed for an application for an air permit on December 5, 1988, to develop and produce the Fairway Field three miles south of the entrance to Mobile Bay. Individual well platforms are connected to a Central Production Facility (CPF). Production from

[115]This section is based on the following articles:

Gallaher, Dale and Michael J. Mahoney, "New technologies used in development of sour Fairway gas," OGJ, February 22, 1993, p. 57 - 62.

Gallaher, Dale and Michael J. Mahoney, "Fairway sour gas development proves new materials, monitoring," OGJ, March 1, 1993, p. 76 - 79.

"Yellowhammer: Alabama's Newest Resource," Shell internal undated publication.

Table 6.5
Exxon Plant Gas Per Day 1/96 - 12/97
MMCFD

		Wells												Sales	Sulfur Production
	Total gas	62-1	63-1	78-1	111-1	111-2	111-3	112-1	112-2	115-1	116-1	114-2	827-1		long tons
Jan 96	369.803	18.342	26.255	56.190	26.293	66.699		42.251	28.146	10.912	27.049	33.872	33.794	349.356	197.184
Feb	361.918	17.460	26.151	55.971	26.584	66.622		38.000	24.390	11.179	26.838	32.984	35.740	341.231	188.793
March	354.276	16.604	26.320	57.309	25.489	65.851		31.322	26.919	10.753	26.293	33.148	34.268	333.180	189.715
April	343.533	15.684	27.426	55.109	24.805	64.476		30.564	27.352	10.373	26.346	27.477	33.927	322.650	175.432
May	342.871	15.955	26.098	55.480	24.776	64.103		31.311	25.319	10.503	28.036	27.809	33.481	323.156	179.809
June	318.139	15.844	27.122	56.093	23.869	62.716		9.728	23.772	10.498	27.766	27.674	33.056	299.799	176.438
July	303.820	14.927	26.438	55.115	23.933	61.041		0.000	24.902	10.150	25.060	29.838	32.416	285.236	171.502
August	305.442	15.073	27.305	54.670	23.802	60.348		0.000	25.634	9.692	19.468	37.142	32.310	286.616	165.085
Sept.	326.871	25.932	32.609	54.082	25.028	59.219		0.000	24.945	10.135	26.745	36.763	31.414	307.437	211.976
Oct.	345.252	29.649	34.330	54.703	25.880	58.617		0.000	24.094	11.233	30.946	40.240	35.559	324.367	225.331
Nov.	342.790	31.833	35.017	55.994	25.194	58.232		0.000	23.435	10.906	29.584	37.036	35.559	320.568	228.521
Dec	336.454	31.324	33.505	56.499	24.698	57.543		0.000	23.199	9.887	28.691	36.479	34.628	315.998	233.454
Jan 97	323.529	27.930	30.670	55.238	24.778	56.785		0.000	22.078	9.529	26.708	36.488	32.891	304.461	216.844
Feb.	319.873	26.106	29.612	56.750	23.933	58.930		0.000	22.916	7.321	26.457	34.893	33.709	298.624	209.479
Mar	342.898	21.568	29.380	56.936	23.033	58.562	36.162	0.000	16.527	9.310	25.097	32.794	33.529	322.317	227.720
April	364.524	16.143	29.291	55.961	23.489	57.886	81.905	0.000	0.000	9.227	24.140	34.176	32.307	342.205	254.940
May	362.082	19.067	28.826	54.781	22.906	56.425	80.262	0.000	0.000	9.550	22.476	36.230	31.558	342.406	264.948
June	357.120	19.416	28.334	55.001	22.651	55.011	78.344	0.000	0.000	8.671	25.244	33.445	31.002	334.106	260.923
July	342.793	20.662	26.560	52.118	21.567	50.991	74.111	0.000	0.000	9.373	24.757	32.856	29.799	319.802	247.640
August	358.390	26.261	26.625	53.874	21.805	51.154	74.830	0.000	5.853	9.531	25.120	33.061	30.276	335.166	271.217
Sept.	383.054	25.642	25.141	54.058	21.346	50.503	73.294	17.586	21.161	8.409	23.916	32.659	29.340	360.993	269.194
Oct.	401.757	24.157	23.332	54.290	22.446	51.822	72.691	41.023	20.672	8.367	22.572	31.663	28.723	377.521	282.238
Nov.	407.684	23.543	28.998	54.581	21.439	53.296	74.502	38.424	19.486	9.590	22.661	31.893	29.281	380.804	273.828
Dec	383.913	23.806	31.295	54.453	21.252	51.563	70.359	24.825	19.480	8.709	22.896	26.772	28.504	360.298	266.545

Source: Alabama Oil and Gas Board, 1997.

the CPF is pipelined 17 miles to Shell's Yellowhammer gas treatment plant. The plant, named for the Alabama state bird, is located east of the Mobil Mary Ann Plant in the general vicinity of Coden, Alabama. The plant is sized to process 200 MMCFD of sour gas (0.8 percent average H_2S) and produce 190 MMCFD sales gas, 60 LTD sulfur and as much as 2,300 b/d mixed NGLs.

The Shell Fairway gas contains about 3 percent CO_2, NGLs that are not present in either Mobil's or Exxon's dry gas, and H_2S in the wells that ranges from 100 ppm to 1.5 percent within tract 113; 150 ppm in well 132-1. The gas in the west dune of Shell's tract 113 has lower H_2S than the gas in the east dune. (See dunes in Figures 5.8 and 5.9.)

Like Mobil's and Exxon's plants, Shell's plant was built to achieve rigorous environmental protection and safety standards. Computer operated electronic sensors, automatic shutdown devices, and warning systems monitor all processes. Electronic sensors throughout the surrounding community constantly monitor for H_2S.

Downhole production tubing, wellheads, well flow lines and primary processing on the CPF employ bimetallic nickel-alloy CRA materials. Downstream of the corrosion inhibitor injection, Shell employs carbon steel for the pipelines to shore. In contrast to Exxon's and Mobil's processing approach, Shell's gas is dehydrated onshore, rather than on the platform. Shell avoids corrosion of the pipeline and fittings by using Champion T265 corrosion inhibitor chemical, which Shell developed. As pipeline corrosion is a significant concern, and Norphlet gas has all of the ingredients necessary for severe metal-loss corrosion—H_2S, CO_2 and free water—Shell's approach is unique among the Norphlet producers. The liquid hydrocarbons and water are separated in the first step at the plant. Then the contaminants in the gas are removed—H_2S and CO_2—and the gas, NGLs and sulfur are sold. Pipelines from the offshore field bend around Dauphin Island to avoid underwater magnetic anomalies possibly related to sunken ships and artifacts from the Battle of Mobile Bay.

Shell planned for a budget of $440 million to develop gas wells, offshore facilities, pipeline system, and the Yellowhammer plant, broken into the following categories. The plant was designed to accommodate peak production rather than a reduced flat production profile.

	Millions
Wells	$175
Platforms/Jackets	$20
Offshore Facilities	$25
Pipelines/flowlines	$55
Yellowhammer Plant	$90
Future wellfield improvements	$75
Total	$440

The construction contract for the plant was awarded to a team comprised of BE&K of Birmingham and Davy McKee Corp of Tulsa. Davy performed the engineering and major equipment procurement services. BE&K constructed the plant. Local contractors, David Volkert and Associates of Mobile, and J. H. Adams of Chickasaw constructed the plant office building and access roads. Construction of the plant, building and roads required about 400 workers. During construction, the Yellowhammer plant created more than 500 jobs, primarily instate. Construction started in 1989 and was completed in later 1991. Start up occurred on December 5, 1991. The plant operates with 23 technicians and 14 staff. Offshore operations are handled by four crews of two technicians each.

6.3.2 Shell Fairway Field Production History

Figure 6.9 shows that Shell's production was sustained near their 200 MMCFD plant capacity between September 1992 and March 1994. Production has declined since. The field also has scaling problems related to calcium fluoride and calcium carbonate. Well 113-3 has been down for a workover since December, 1997. The Yellowhammer gas plant processed between 92 - 170 MMCFD during 1996 and 1997 including 10 - 11 MMCFD from Mobil's 95-3 well as shown on Table 6.6. With Shell's declining production, Mobil's 3.2 percent H_2S gas fits into Shell's processing capacity. Shifting the gas to Shell made room in the Mary Ann Plant for Mobil to take in the 823-A4 gas. Gas from Chevron's 1.6 percent H_2S well 863-3, which came online in February 1997 at 18 MMCFD, is now being processed at Shell's plant. The well averaged 39 MMCFD during the fourth quarter, 1997. Shell still has unused capacity in its Yellowhammer plant.

6.3.3 Federal 821 Field and Shell Summary

Shell purchased the producing BP joint federal/state 821/109 Field in August 1996 (92.5 percent federal/7.5 percent state). BP had only the one successful Norphlet discovery. The 821 gas, 100 ppm H_2S, will continue to be processed offshore on the 821 platform. Pipeline quality gas is brought to shore in Mobile County on DIGS for connection with the interstate pipeline. Figure 6.10 shows the 821 production history. The field shut down in October 1994 with a severe scaling problem that plugged the well. After that, BP constrained production to 15 MMCFD to manage the scaling accumulation problem. Shell hopes to restore production to about 20 MMCFD. Shell is evaluating a second well on tract 821.

6.4 Development and Production of Union and Chevron Federal Projects

Union and Chevron dominate recent Norphlet development activities on the eastern and western edges of the federal Mobile Bay OCS. These companies acquired the acreage for much lower lease bonus amounts as shown in Section 3.0 because they started later, after gas prices dropped. But nothing is low cost when dealing with the Norphlet.

Development of Union's and Chevron's Norphlet discoveries in western Mobile Bay OCS overcame superpressurized reservoirs (>15,000 psi) as well as the other hostile downhole challenges encountered in Norphlet reservoirs: H_2S, CO_2, water, 420° F temperatures.[116] Several gas wells have been damaged or lost during either completion or start-up, as show on

[116]Offshore, "Unocal building range of solutions for drilling deep Norphlet environment," June, 1995, p. 32 - 33.

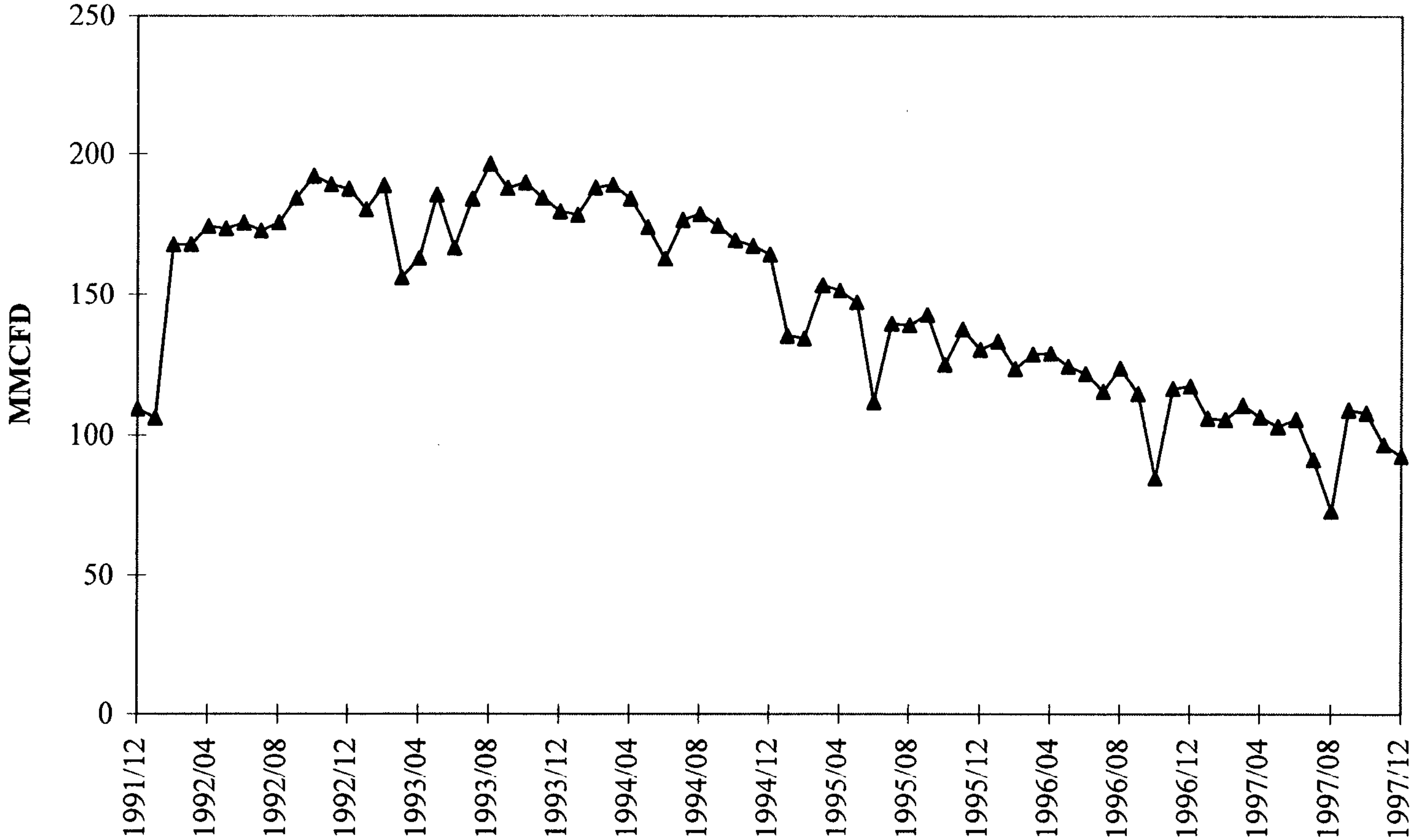


Figure 6.9. Shell Fairway Field Gas Production per Day.

Source: AOGB, 1998.

Table 6.6
Shell Gas Per Day 1/96 - 12/97
MMCFD

		Wells								Sulfur
	Total gas	113-1	113-2	113-3	113-4	132-1	Mobil 95-3	Chevron 863-3	Sales Gas	Production Long tons
Jan 96	144.154	29.085	30.529	22.494	22.623	28.416	11.008		135.381	20.129
Feb	132.013	26.115	26.913	15.104	29.889	25.360	8.726		124.048	16.552
March	138.640	27.108	29.288	15.288	30.946	25.944	10.066		131.261	18.935
April	139.006	26.437	27.872	19.968	29.160	25.501	10.068		131.761	22.933
May	135.156	26.098	26.962	18.109	28.349	24.818	10.821		130.597	23.000
June	133.049	25.724	25.894	19.205	27.373	23.401	11.429		128.371	21.833
July	126.902	24.730	24.775	17.193	26.436	22.157	11.610		121.729	18.226
August	130.641	25.631	26.453	18.345	26.514	22.691	11.008		124.348	16.194
Sept.	124.971	25.876	24.680	16.496	25.039	22.467	10.414		120.674	19.633
Oct.	92.185	19.692	18.844	10.362	18.862	17.129	7.296		86.592	13.806
Nov.	129.369	26.510	25.359	15.419	26.042	23.016	13.023		121.110	17.100
Dec	128.751	26.958	24.346	18.395	25.083	22.421	11.548		119.200	17.387
Jan 97	122.447	26.690	22.684	16.497	23.545	21.428	11.603		107.792	18.452
Feb	123.769	26.294	23.068	10.989	23.675	21.606	11.449	6.688	114.658	18.714
Mar	144.375	26.084	22.678	17.595	23.222	20.977	12.623	22.417	134.982	21.548
April	164.969	25.178	21.150	15.176	21.751	19.763	15.508	42.622	150.287	20.484
May	166.298	25.577	21.491	14.317	22.212	19.540	19.544	45.508	157.597	22.323
June	170.454	24.390	20.466	17.372	21.327	18.713	20.960	43.756	155.647	22.355
July	122.265	24.904	20.483	5.103	21.635	19.405	23.465	9.541	116.075	17.871
August	96.344	22.877	12.657	6.481	19.350	11.662	25.816	0.000	90.745	15.129
Sept.	134.840	23.542	20.602	14.874	19.716	26.733	22.035	5.122	121.980	20.032
Oct.	154.597	24.641	20.723	13.723	21.289	27.565	13.508	34.455	147.574	31.903
Nov.	155.539	23.685	19.192	6.158	19.215	25.511	15.926	42.377	144.116	30.032
Dec.	142.843	26.143	18.856	0.517	19.212	28.018	12.543	38.768	134.380	49.548

Source: Alabama Oil and Gas Board, 1997.

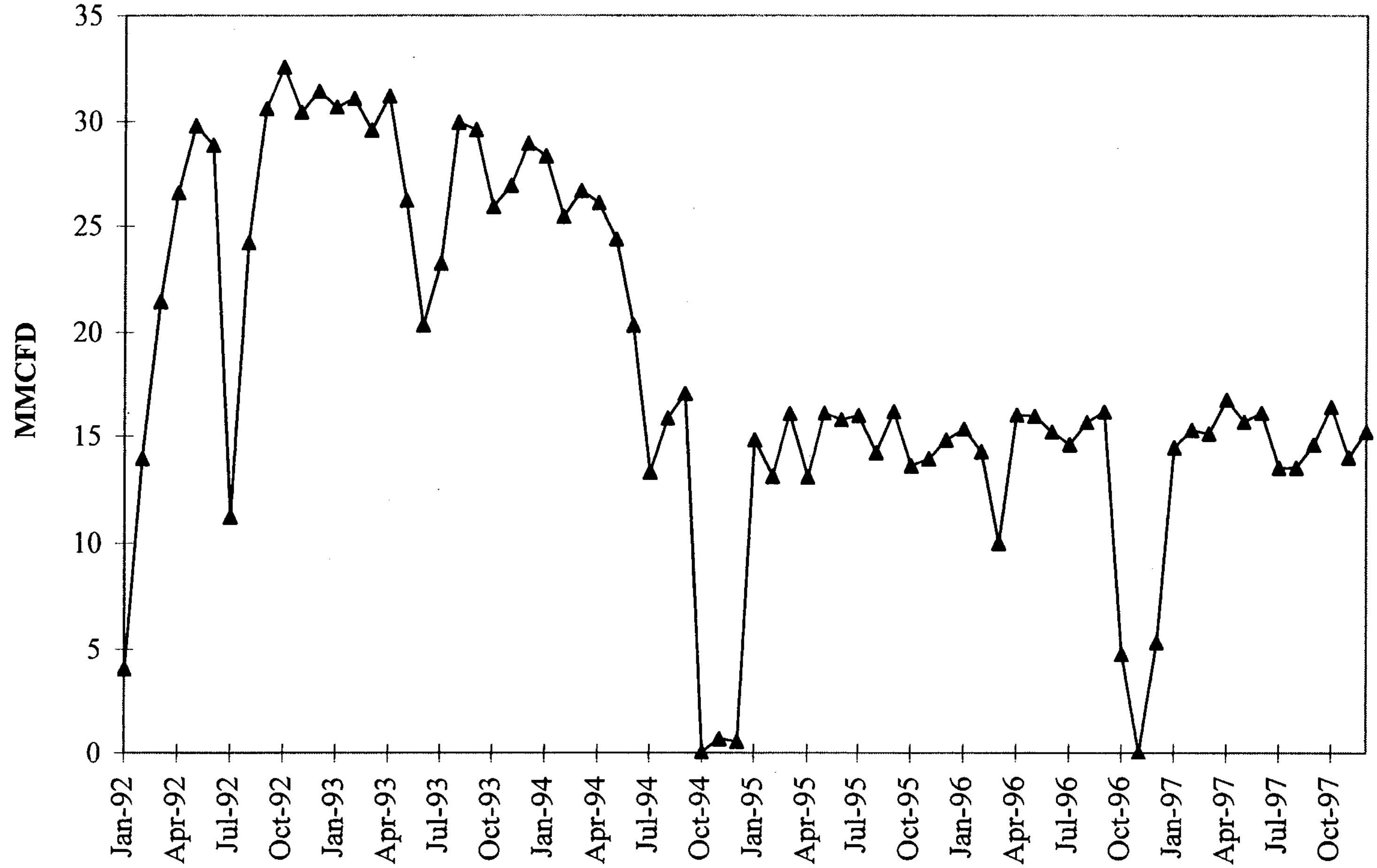


Figure 6.10. State 109 / Mobile 821 Field Gas Production per Day.

Source: Dwights/PI, 1998; AOGB, 1998.

Table 6.7. Chevron's well 861-1 blew out underground in 1985 after discovering Norphlet gas. Three of the wells have a produced water problem; i.e., so much water has intruded that the wells are either P&A'd or only can produce at a reduced rate. This is the same problem that Shell has with the BP-completed well 821-1. Norphlet wells that are completed too close to the water contact at the bottom of the reservoir can develop a water coning problem due to the tight rock. Assuming a cost of close to $30 million to drill and complete a Norphlet well, these six wells represent a $180 million problem with a lot of lost production.

Union and Chevron combined are producing close to 150 MMCFD Norphlet gas at year end 1997 with plans that could add at least 100 MMCFD of new production by the end of 1998. The problem wells have resulted in lost production easily in the range of 150 MMCFD. Assuming $1.00 per MCF netback to wellhead these losses total nearly $55 million annually. Everything is big when it comes to Norphlet wells.

Table 6.7
Union's and Chevron's Problem Wells

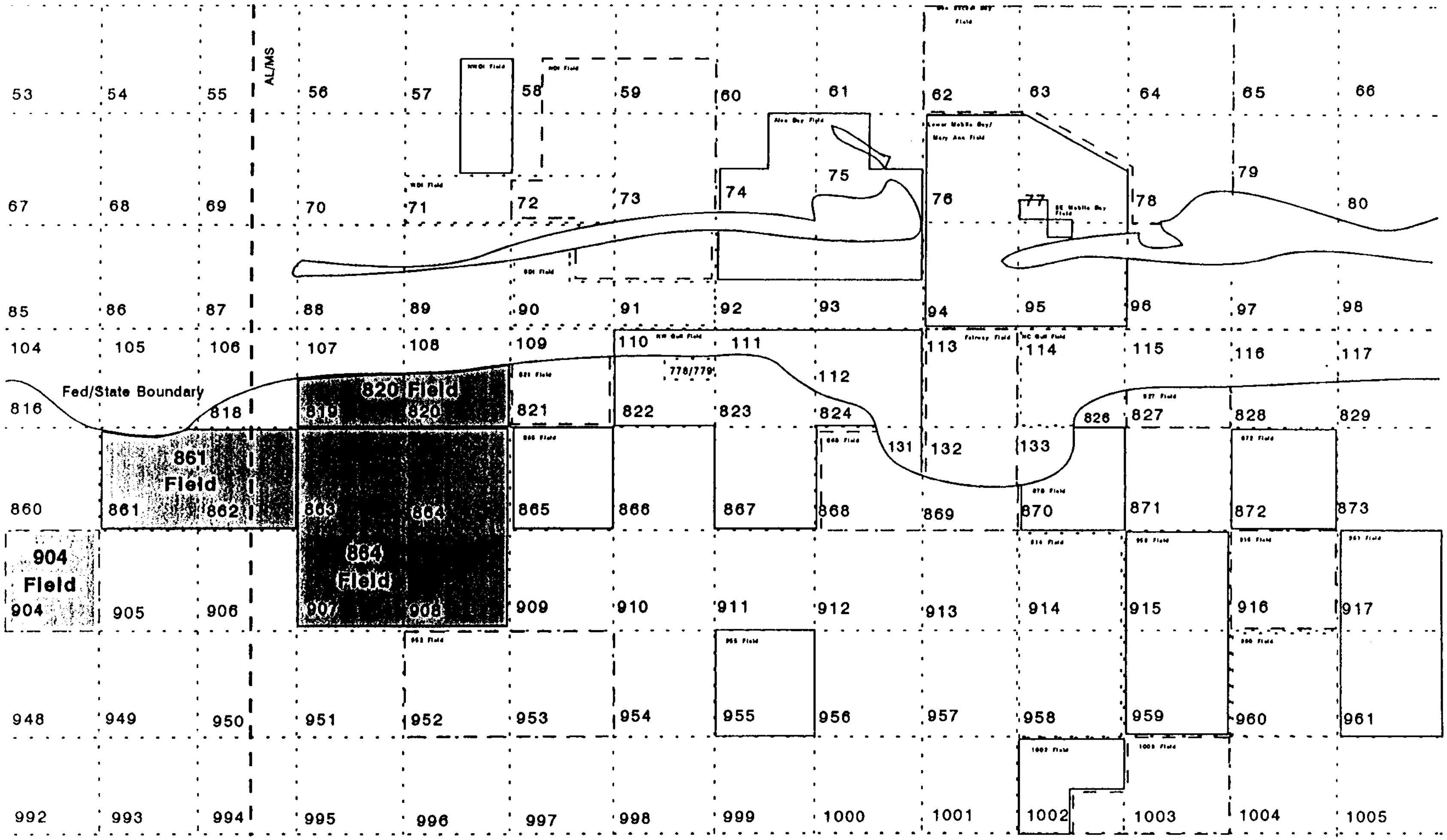
Well	Operator	Problem	Problem Date	Status 12/97
861-1	Chevron	Underground Blowout	1985	P&A
861-8	Chevron	Water Intrusion	August 1994	producing at reduced rate
904-1	Union	Casing/Tubing excessive wear	August 1994	P&A
864-3	Chevron	Water Intrusion	August 1996	P&A
916-B3	Union	Water Intrusion	June 1995	P&A
872-1	Chevron	Formation Plugged by Kill Fluid	September 1995	producing at reduced rate

Source: Telcons with Union and Chevron Personnel, April 1997.

6.4.1 Western Mobile OCS

Union and Chevron are developing discoveries in the 861, 904, 820 and 864 Units on the Mississippi side of the Mobile OCS. These include processing on Central Processing Facilities (CPF) on platforms at tracts 864 and 904. Together these facilities can process 230 MMCFD of Norphlet gas. Figure 6.11 shows the location of these fields.

Union's 904 platform includes two wells and processing capacity sized to handle 80 MMCFD of Norphlet gas plus separate crew quarters. Four crew members serve a seven day rotation. Processing anticipates 120 ppm average H_2S. Gas from tracts 904 and 861 is processed on the 904 platform and flows to shore via a 10-inch connection to the Chandeleur pipeline to the Pascagoula refinery, where it connects to the Koch Gateway Interstate.



Source: AL Oil and Gas Board, 1986, 1993a; MMS, 1991, 1993a.
Blocks and structures not drawn to scale.

Figure 6.11. Western Mobile OCS Union & Chevron Fields.

Unocal's initial production came from the 904 Field, which started with 904-1 on December 22, 1993 at 20 MMCFD, as can be seen on Figure 6.12. The well reached a peak production rate of 22.3 MMCFD—well below its record test rate—but was lost in August 1994. The well has been P&A'd. Chevron started production from 861-8 March 1994, flowing to Union's 904 facility. The gas is 120 ppm H_2S. The well initiated production at 30 MMCFD, but developed water problems and was off production from August 1994 until January 1995. It has never produced near the high rates of its initial production, currently maintaining 10 - 12 MMCFD. This was the only production to the 904 facilities after 904-1 was lost until Union brought a new well 904-2 on line December 24, 1996 at 32 MMCFD. The well stepped up to 52 MMCFD in February 1997. This well solved the water coning problem encountered in so many Norphlet wells by being completed at the top of the reservoir sand, just below the pyrite zone found between the Norphlet and Smackover. The ultimate production rate from the 904 field is yet unknown.

Chevron initiated production from its 820-1 well October 21, 1996 at 25 MMCFD, ramping up to 50 MMCFD for the month of April 1997. The well averaged 34 MMCFD during the fourth quarter 1997. This well is 100 ppm H_2S. Chevron's well 864-3 started production at 20 MMCFD October 21, 1996, but encountered a water production problem and was shut in. It was P&A'd April 1997. Well 864-4 spudded in July, 1997, to replace 864-3. The well came online in December, 1997, at 16 MMCFD, 40 ppm H_2S. Ultimately, the well is expected to produce 30 MMCFD. Well 863-3 initiated production February 19, 1997 at 18 MMCFD. The well tested with H_2S unexpectedly high, 1.6 percent, to process on the 864 platform. Production was delayed until a pipeline could be installed to Shell's Fairway Field for processing in the Yellowhammer Plant. Well 863-3 produced 44 MMCFD April thru June 1997, encountered a mechanical problem with the safety valve and was shut-in through April 1988 for repairs. The well returned to service at 44 MMCFD. Figure 6.12 shows that Chevron's and Spirit's western Norphlet fields reached peak production April thru June, 1997, before they were beset with problems. Lost production from 863-3 and the downturns of 820-1 and 904-3 explain the October, 1997, dip. Added new production from 864-4 partially explains the December, 1997, upturn.

Chevron spudded well 819-1 September 1, 1996. The well reached total depth (TD) December 1996 and confirmed gas. The well was completed in December, 1997, and added to production January 1, 1998, at 22 MMCFD. Flowlines were constructed between the well and the 864B Central Production Facility. Flowline bundles are described as a six-inch gas pipeline, a three-inch solvent pipeline and a two-inch fuel gas pipeline.

Chevron contracted Ralph M. Parsons to provide design and procurement services for a $50 million natural gas treatment plant to be built at Pascagoula. The plant was described as the first of three phases, each providing 300 MMCFD of capacity. Planned completion was 1994.[117] Chevron decided, however, to forego onshore processing and treat its gas either on its own 864 platform, or Union's 904 and 916 platforms. This saved the cost of lengthy, expensive carbon steel pipelines from the eastern and western Mobile Bay OCS areas to Pascagoula. Instead, Chevron delivers its pipeline quality gas to DIGS for conveyance to the Chandeleur Pipeline to

[117]OGJ, Industry Briefs, October 19, 1992, p. 40.

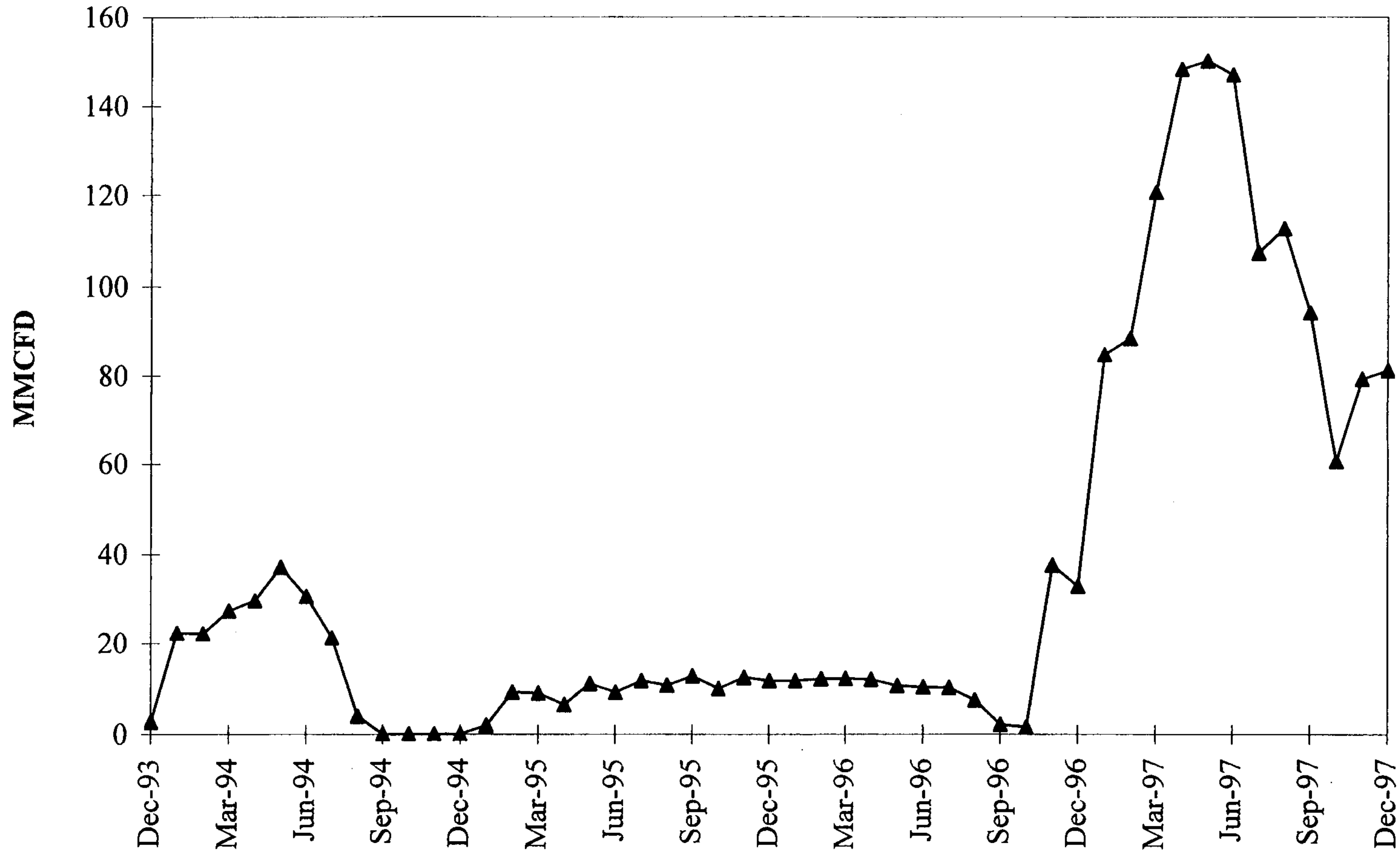


Figure 6.12. Mobile 820, 861, 863/4 and 904 Fields Norphlet Production.

Source: Dwights/PI, 1998; Foster Associates, Inc., 1998.

Pascagoula and the Koch interstate connection.

Chevron constructed facilities on the 864B platform Central Production Facility capable of processing 150 MMCFD of sour gas. In April 1998, Chevron is treating approximately 75 MMCFD gas from its wells 820-1, 864-4, and 819-1 on the platform. Spirit is treating 904-2 and 861-8, about 50 MMCFD, on the 904 CPF. Planned new well 904-3 will be treated on the 904 CPF.

Table 6.8 summarizes Union's and Chevron's activities on the western side of the Mobile OCS. Counting January 1998 production plus the 863-3 workover well, five wells produced about 170 MMCFD, with about 120 MMCFD of that being processed in either the 904 or 864 CPFs. Chevron's planned 862-1ST, a second well in the producing 863 reservoir, 863-4, planned for later in 1998, and 819-2 likely will fill the capacity of their 864 processing facility during 1999. A Miocene well, 861-9, was completed in December 1996. This well is reported to be pressurized with the Norphlet gas that escaped from Chevron's 1985 blowout. It is treated on the 904 platform before transport to Pascagoula on the Chandeleur pipeline.

Table 6.8
MO 904, 861, 820 & 863/4 Production Summary & Plans

Well	Operator	Formation	Start Up Date	Production Rate 1/98 MMCFD
904-1	Union	Norphlet	12/93	P&A
904-2	Union	Norphlet	12/96	39
861-8	Chevron	Norphlet	3/94	10
861-9	Chevron	Miocene	12/96	7
864-3	Chevron	Norphlet	10/96	P&A
820-1	Chevron	Norphlet	10/96	32
863-3	Chevron	Norphlet	2/97	Workover 44-April 1998
864-4	Chevron	Norphlet	12/97	~16
819-1	Chevron	Norphlet	1/98	~22
Total		**Combined**		**~170**
862-1ST	Chevron	Norphlet	1999	gas
863-4	Chevron	Norphlet	1999	gas
819-2	Chevron	Norphlet	1999	gas
904-3	Union	Norphlet	1999	gas

Source: U.S. DOI, MMS, 1998; Chevron, 1998; Union, 1998.

6.4.2 Eastern Mobile OCS

The eastern area of Mobile OCS includes Chevron's 100 percent owned 872 Field comprised of tracts 872 and 873 plus the 916 Unit consisting of 6-1/4 blocks shown on Figure 6.13—871 S/4, 915, 916, 917, 918, 961, and 962. Union and Chevron are equal 45.7 percent owners of the 916 Unit, with Bechtel's Fremont Energy Corp owning the rest. Union is the operator, although Chevron has drilled individual wells that provide gas to the processing facilities. The state boundary likely artificially truncates the Norphlet play in the area to the Alabama side of the line.

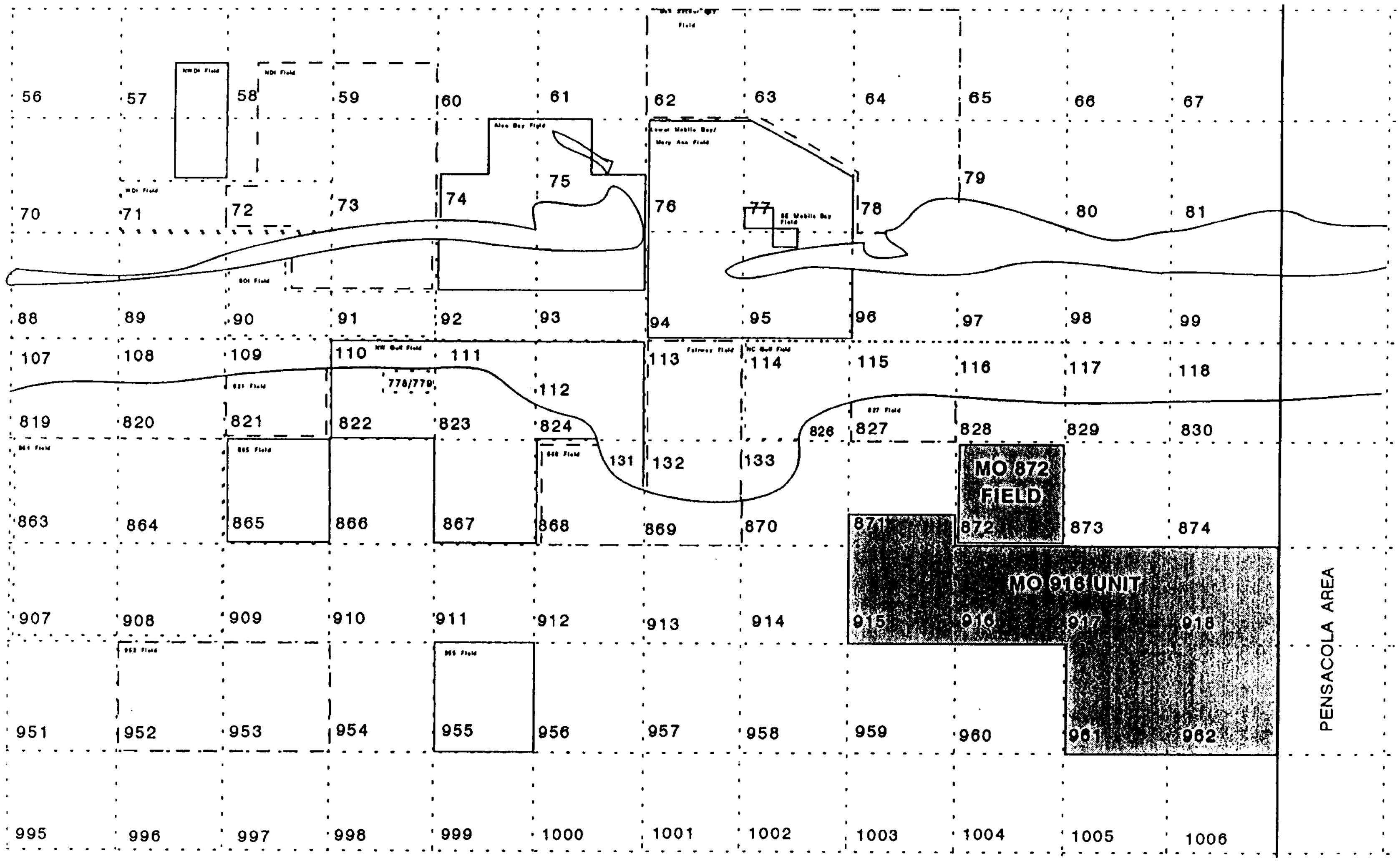
The Mobile 916 area facilities are called the Fort Morgan Complex because the field is located about 12 miles southeast of Fort Morgan. Facilities include a Central Processing Facilities platform, crew quarters platform, two wellhead platforms and two caisson wells. The three bridge-connected platforms are capable of producing and treating on the platform 150 MMCFD sour gas and 30 MMCFD sweet Miocene gas. The Norphlet is 60 ppm H_2S, 4.5 percent CO_2 flowing at 300° and 15,835 psi. The commingled pipeline quality gas is shipped on the 20-inch DIGS pipeline to the Mobile County Interstate connection. Enercon Engineering Inc, Houston, provided the engineering and procurement for the production facility.[118] Like other Norphlet developments, extensive CRA is used for flowlines upstream from dehydration. Eight crew members serve a seven day on/off rotation.

The Fort Morgan Complex initiated production in April 1995. Union started production from 916-A2 in April 1995 at 17 MMCFD; this ramped to 32 MMCFD in June and averaged 25 MMCFD through the end of 1995. 916-B3 came on line in April and hit 15 MMCFD in June 1995 before encountering a water intrusion problem.[119] Chevron started-up well 917-A2ST in April 1995 producing 40 MMCFD, 80 ppm H_2S. Production was down to 11 MMCFD in April 1997. Union, which had a different view of the structure's geology, is not a partner in this well. Chevron's 100 percent-owned well 872-A1 began production March 1996 and averaged 11 MMCFD in mid-year. Well 961-A2 initiated production July 31, 1996 at 24 MMCFD. The well ramped up to 50 MMCFD in February, 1997, and averaged 35 MMCFD during the fourth quarter, 1997. Union's two Miocene wells began production in April 1995.

Figure 6.14 shows Norphlet production from the two fields in the eastern Mobile OCS.
Union and Chevron produced between 100 - 110 MMCFD Norphlet gas delivered to the 916 platform facilities from five Norphlet wells from September, 1996, thru April, 1997. The loss of 916-B3 and a repair on 916-A2 caused the spike shown down to 58 MMCFD in June, 1997. Table 6.9 summarizes the producing wells to the 916 CPF.

[118]OGJ, "Another Mobile Block production facility nears completion," Jan. 30, 1995, p. 91.

[119]OGJ, "Unocal steps up gas/condensate production," May 29, 1995, p. 24.



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Source: Foster Associates, Inc., 1997.

Figure 6.13. Mobile 916 & 872 Units.

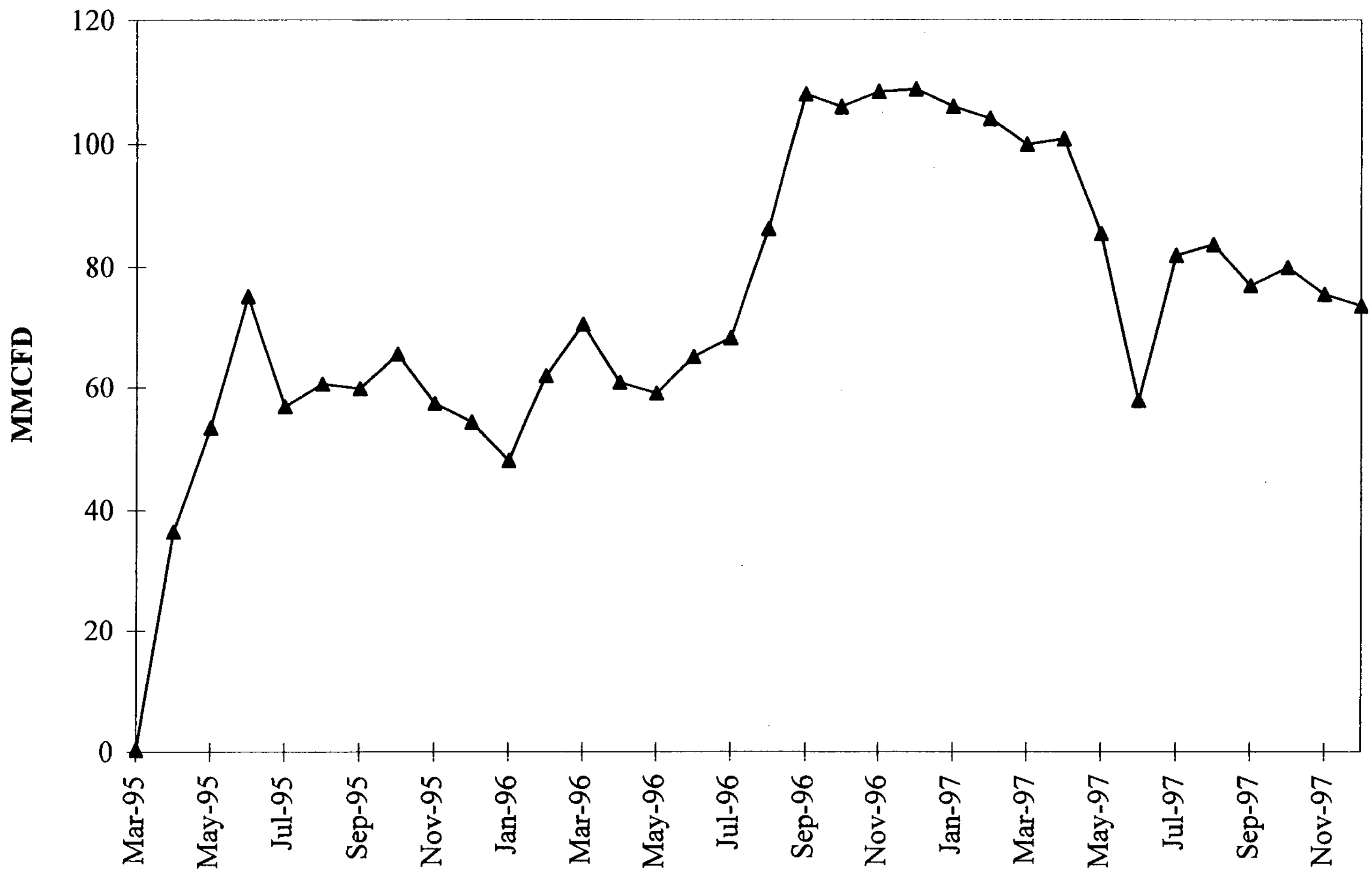


Figure 6.14. Mobile 916, 961, and 872 Fields Norphlet Production.

Source: Dwights/PI, 1998; Foster Associates, Inc., 1998.

Table 6.9
MO 916 Processing

Well	Operator	Formation	Start Up Date	Production Rate 4Q/97 MMCFD
916-A2	Union	Norphlet	4/95	19
916-B3	Union	Norphlet	4/95	P&A
917-A2	Chevron	Norphlet	4/95	10
872-A1	Chevron	Norphlet	3/96	12
961-A2	Union	Norphlet	7/96	34
915-1	Union	Miocene	4/95	2
961-1	Union	Miocene	4/95	2
Total		Combined		79

Source: U.S. DOI, MMS, 1998.

Union and Chevron will spud two wells in the area, 918-1 and 871-1 during 1998. Plans include a drilling schedule that will add as many as 12 more Miocene and Norphlet wells between 1998 and 2004 as economics justify.

6.5 Production Facilities Summary

Extensive gas industry activity in Coastal Alabama has yielded over 7.5 TCF recoverable reserves and annual production over 1.0 BCFD from 17 active Norphlet fields. Six state Norphlet fields and ten federal Norphlet fields are producing with one more, Destin Dome, scheduled to begin development activity when its DPP, submitted December 1996, is approved. Production will begin in 2001. One joint state/federal field, 821/109 straddles the three-mile line with 92.5 percent of the field and production considered federal.

6.5.1 Producing Fields and Production Increases by End of 1998

Forty wells were producing 1.1 BCFD in the active 17 Norphlet fields in February, 1998, averaging 27.5 MMCFD per well. Over the last 24 months, production ramped from 880 MMCFD in January, 1996, to a peak over 1.1 BCFD in April 1997, and then dropped below 1.0 BCFD at the end of 1997. Figure 6.15 shows that state production has remained stable near 600 MMCFD over this period, as Exxon's 112 workovers and new production from Mobil's 95-5 and 75-1 overcame declines from Shell's Fairway field. Federal production increased from 300 MMCFD beginning in October, 1996, to 530 MMCFD at its peak in April, 1997. Production thereafter was offset by lost production from problem wells (863-3 & 916-B3) and natural decline observed in Mobil's 823 field. New federal wells increased year end 1997 net production by 80 MMCFD above the January, 1996, production level. Table 6.10 shows ten

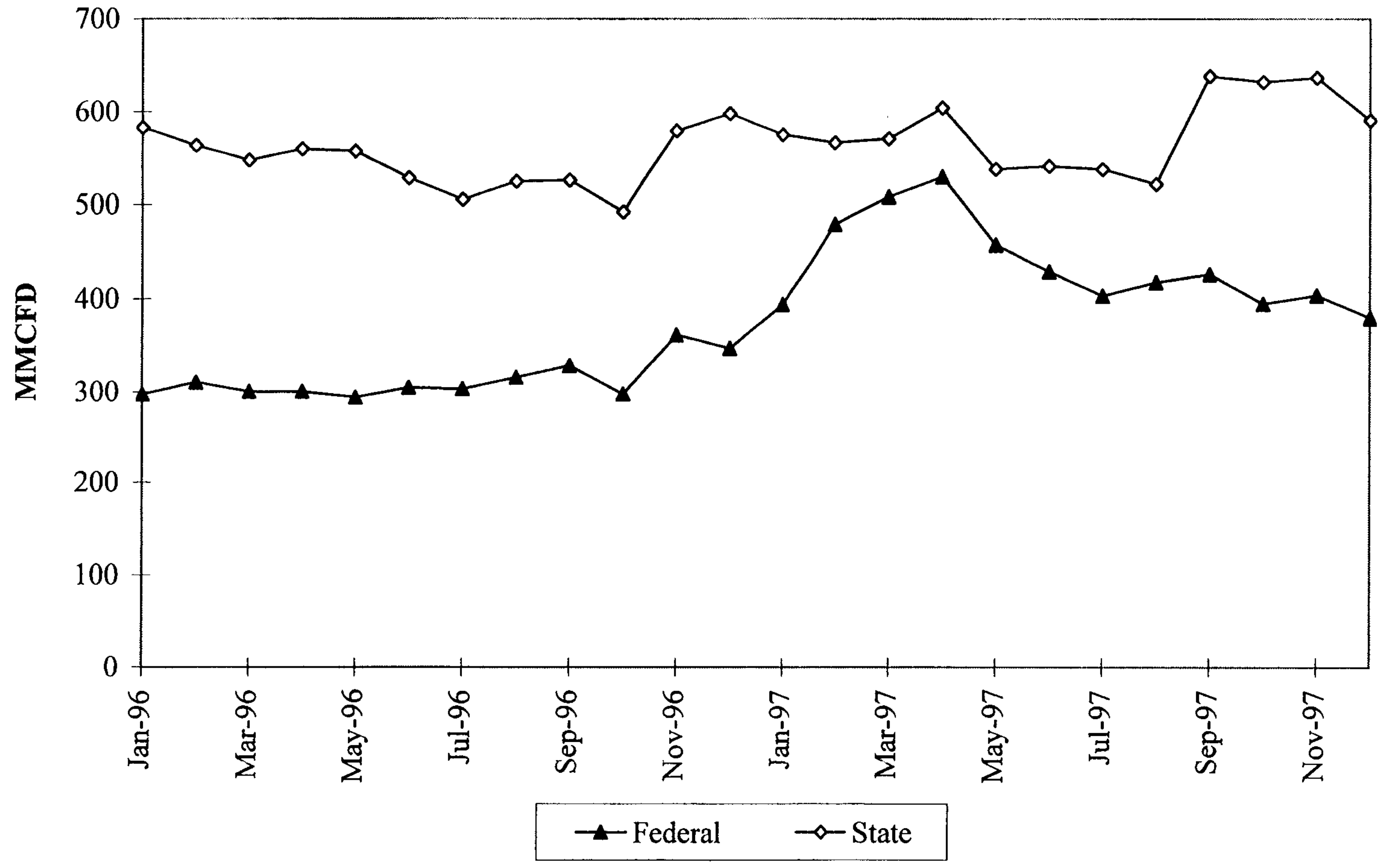


Figure 6.15. State and Federal Norphlet Production Offshore Alabama (1996 - 97).

Source: AOGB, 1998; Dwights/PI, 1998; Foster Associates, 1998.

new wells added to production during 1996-1997, plus two added in January-February, 1998. Ten wells added 499 MMCFD of new production at their peaks, sustaining 368 MMCFD based on year end 1997 data. Recent information about the new Chevron and Exxon wells adds 76 MMCFD of new production.

Table 6.10
Norphlet Wells Added to Production during 1996-97

Operator	Field	Well	Start-up	Peak Production MMCFD-Date	Recent Production
Chevron	872	872-1	3/96	14-3/97	13
Spirit	961	961-1	7/96	50-1/97	32
Chevron	820	820-1	10/96	50-4/97	32
Mobil	Mary Ann	95-5	11/96	72-12/96	40
Spirit	904	904-2	12/96	60-8/97	39
Mobil	869	869-3	2/97	83-3/97	61
Chevron	863	863-3	2/97	44-5/97	44
Exxon	NWG	111-3	3/97	82-4/97	70
Mobil	Aloe Bay	75-1	7/97	28-9/97	21
Chevron	864	864-4	12/97	16-12/97	16
Chevron	820	819-1	1/98	22-2/97	22
Exxon	NCG	114-3	2/98	54-4/97	54
Total Added Production			**1997**	**499**	**368**
			4/98	**575**	**444**

Source: Telcons with operators.

Besides the five wells planned for the Destin Dome Field development, 16 wells are shown on Table 6.11 that potentially will added to production by year end 2000. The wells are listed as TA, drilling, workovers, or under evaluation for spudding within 12 months. Table 6.11 shows their December 1997 status.

Table 6.11
Norphlet Wells to Add to Potential Production by Year-end, 2000

Operator	Field	Well	Status December, 1997
Chevron	820	819-1	TA; Start-up January 1, 1998
Exxon	North Central Gulf	114-3	TA; Start-up February 10, 1998
Mobil	823	823-A5	TD; 2/98
Mobil	914	914-4	Drilling
Shell	Fairway	113-3	Complete Workover
Chevron	861	862-1	Spud Sidetrack, 1998
Chevron	863	863-4	Spud, September 1998
Chevron	819	819-2	Planning
Mobil	Mary Ann	95-4	TA; reevaluation 1998
Exxon	867	867-1	TA; Produce 1998
Mobil	BSB	61-1	Spud project w/Exxon, 1998
Mobil	Aloe Bay	75-2	Spud, 1998
Spirit/ Chevron	916	918-1 871-1	Spud, May 1998 Planning
Shell	821	821-2	Planning
Spirit	904	904-3	Spud, After 918-1

Source: Telcons with operators.

6.5.2 Sour Gas Processing Capacity and Utilization

The start up of Mobil's Aloe Bay Field, Mobil's 823-5 and 914-3 wells, expansion of Chevron's 820 and 864 Fields by two producing wells, recovery of Shell's 113-3 workover, and Exxon's 114-3 well will move production from Coastal Alabama fields toward capacity of existing gas treating facilities during 1998. Table 6.12 shows the existing processing capacity and amounts of sour gas processed in these facilities during December 1997. The plants operated at 72 percent of capacity at year end, 1997.

Table 6.12
Gas Processing Facilities in Mobile Bay Region
(MMCFD)

Operator	Onshore Capacity	Offshore Capacity	Total Capacity	Capacity Use 4Q Avg/ 1997
Mobil Mary Ann	180	0	180	132
Mobil 823	300	0	300	207
Shell (821)	0	60	60	15
Yellowhammer	200	0	200	151
Exxon	400	0	400	398
Unocal 916	0	150	150	62
Unocal 904	0	80	80	50
Chevron 864	0	150	150	79
Total Capacity	**1080**	**440**	**1520**	**1094**

Source: Foster Associates, 1997; Alabama Oil and Gas Board, 1997.

6.5.3 Gas Production Summary through 1997

Mobile Bay Norphlet production exceeded 1 BCFD on a sustained basis for the first time in 1997, averaging 1.02 BCFD for 1997, 371 BCF for the year--18 percent more than 1996 production of 863 MMCFD Norphlet gas. Annual state production since 1988 is shown on Table 6.13. Annual federal production is shown on Table 6.14. Cumulative production has amounted to 1.7 TCF of Norphlet; 288 BCF Miocene. Miocene is in decline.

State Norphlet production rose to nearly 550 MMCFD during the first quarter of 1997 with the addition of MOEPSI's well 95-5 and Exxon's well 111-3. State production stepped up in the late summer when Aloe Bay well 75-1 came online and when Exxon's workovers on 112-1 and 112-2 come back online. State production averaged 580 MMCFD for the year. Federal Norphlet production increase by 38 percent in 1997 over 1996 and averaged 435 MMCFD.

Gas production began in Alabama state waters in 1987 when MOEPSI first produced gas from its Miocene well in the Southeast Mobile Bay Field. Production from this well was limited and was used solely as fuel for ongoing operations. Production ceased after 1989. The Mary Ann Field began production in 1988. Shell's Fairway Field started up in late 1991 along with MOEPSI's federal 823 Field. BP brought its 821/109 Field online in early 1992, and Exxon started its three fields in late 1993.

Table 6.13
Summary of Gas Production in Mobile Bay State Waters by Reservoir and Field (BCF)

State Field	Current Operator	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Cumulative Thru 1997
Miocene Fields												
East Mississippi Sound	Legacy	-	-	-	-	-	-	-	0.1	1.8	0.1	2.0
Goose Bayou	Legacy	-	-	-	-	-	-	-	0.1	1.3	0.1	1.5
North Dauphin Island	Callon	-	-	-	0.2	19.3	15.9	11.1	7.4	3.8	2.1	59.8
Northeast Petit Bois Pass	Offshore Group	-	-	-	-	-	-	0.4	0.1	1.2	0.5	2.1
Northwest Dauphin Island	Offshore Group	-	-	-	-	0.6	0.9	2.0	1.2	0.9	0.6	6.2
South Dauphin Island	SCANA	-	-	-	-	-	0.6	3.5	2.6	1.5	0.7	8.9
Southeast Mobile Bay	MOEPSI	0.2	0.1	-	-	-	-	-	-	-	-	0.3
Subtotal Miocene		0.2	0.1	-	0.2	19.9	17.4	17.0	11.5	10.5	4.1	80.9
Norphlet Fields												
Aloe Bay	MOEPSI	-	-	-	-	-	-	-	-	-	3.5	3.5
Bon Secour Bay	Exxon	-	-	-	-	-	3.3	25.8	33.8	38.7	38.7	140.2
Fairway	Shell	-	-	-	3.4	63.1	65.8	64.2	50.1	43.7	36.7	326.9
Lower Mobile Bay - Mary Ann	MOEPSI	9.3	12.8	19.9	29.3	29.8	31.6	31.4	34.2	38.8	45.8	283.0
North Central Gulf Mobile Area	Exxon	-	-	-	-	-	1.7	32.0	32.2	32.0	28.3	126.2
Northwest Gulf Mobile Area	Exxon	-	-	-	-	-	11.8	60.0	52.3	46.8	58.1	229.0
State 109/ Federal 821	Shell	-	-	-	-	0.7	0.8	0.5	0.4	0.3	0.4	3.1
Subtotal Norphlet		9.3	12.8	19.9	32.7	93.5	115.0	213.8	203.1	200.2	211.5	1,111.9
Total BCF		**9.5**	**13.0**	**19.9**	**32.9**	**113.4**	**132.4**	**230.8**	**214.6**	**210.7**	**215.6**	**1,192.8**
MMCFD		**26.0**	**35.6**	**54.6**	**90.0**	**310.8**	**362.8**	**632.5**	**587.8**	**577.2**	**590.6**	--

Source: Alabama Oil & Gas Board, 1998.

Table 6.14
Summary of Gas Production in Federal OCS Waters by Reservoir and Field
(BCF)

OCS Field	OCS Blocks	Current Operator	1991	1992	1993	1994	1995	1996	1997	Cumulative Thru 1997
Miocene Fields										
Mobile 823	778, 779, 822, 823, 824, 867	Scana	-	-	2.3	6.8	5.2	3.2	2.1	19.5
Mobile 861	860, 861, 862	Chevron USA	-	-	-	-	-	0.0	2.0	2.0
Mobile 864	863, 864, 907, 908, 909	Chevron USA	-	18.8	20.5	18.2	13.8	11.5	8.7	91.5
Mobile 865	865	Scana	-	-	-	2.9	3.4	2.8	1.5	10.6
Mobile 866	822, 866	Scana	-	-	-	0.9	0.9	1.0	0.6	3.4
Mobile 870	870	Enron	-	-	-	1.1	4.7	5.3	5.6	16.7
Mobile 914	914, 958	Enron	-	-	-	1.0	2.5	1.5	0.7	5.6
Mobile 945	945	Apache	0.1	1.1	0.8	0.6	0.5	0.2	0.1	3.5
Mobile 947	947	Apache	0.1	1.9	1.6	1.0	1.1	0.9	0.6	7.3
Mobile 952	952, 953	Murphy	-	0.8	1.1	1.0	1.0	1.3	3.4	8.6
Mobile 955	955	Murphy	-	1.0	1.4	1.2	1.1	1.0	0.9	6.7
Mobile 959	915, 959	OEDC/Unocal	-	-	-	-	4.9	3.1	1.4	9.5
Mobile 959	960	OEDC	-	-	-	-	0.9	0.6	0.4	1.9
Mobile 961	917, 961	Unocal	-	-	-	-	1.4	1.3	0.8	3.5
Mobile 990	990, 991, VK22	Apache/Enron	0.4	4.3	3.9	2.9	2.5	1.8	1.2	16.9
Subtotal Miocene			**0.6**	**27.9**	**31.7**	**37.5**	**44.0**	**35.4**	**30.0**	**207.1**
Jurassic Fields										
Mobile 819	819	Chevron USA	-	-	-	-	-	-	-	- [1]
Mobile 820	820	Chevron USA	-	-	-	-	-	2.2	14.5	16.7
Mobile 821	821	Shell	-	8.7	10.1	6.0	5.4	4.4	5.5	40.1
Mobile 823	778, 779, 822, 823, 824, 867	MOEPSI	2.7	49.4	44.4	63.1	70.7	65.1	49.8	345.3
Mobile 827	826, 827	Exxon	-	-	0.5	7.0	4.1	11.9	11.0	34.5
Mobile 861	861, 862	Chevron USA	-	-	-	2.0	3.5	3.2	3.3	11.9
Mobile 864	863, 864	Chevron USA	-	-	-	-	-	-	5.1	5.1
Mobile 868	868, 869, 914	MOEPSI	-	-	-	-	-	-	23.3	23.3
Mobile 872	872	Chevron USA	-	-	-	-	-	3.2	4.6	7.8
Mobile 904	904	Unocal	-	-	0.1	3.9	-	0.2	15.9	20.2
Mobile 916	916	Unocal	-	-	-	-	9.7	11.3	7.0	28.0
Mobile 961	917, 961	Unocal/Chevron	-	-	-	-	4.7	13.3	18.7	36.8
Subtotal Jurassic			**2.7**	**58.1**	**55.2**	**82.0**	**98.1**	**114.7**	**158.8**	**569.7**
Total BCF			**3.4**	**86.0**	**86.8**	**119.6**	**142.1**	**150.1**	**188.7**	**776.8**
MMCFD			**63.4**	**247.6**	**265.6**	**347.6**	**404.4**	**456.3**	**518.6**	--

Sources: Dwights/PI, 1998; U.S. Dept. of Interior, MMS, 1998.

[1] Production beginning in 1998.

Chevron initiated its federal Miocene production in 1992 in the 864 Field and started Norphlet production in 1994 in the 861 Field. Unocal started production in the 904 Field in 1993 and the 916/961 Fields in 1995.

Shell and Exxon required 10 and 12 years from the 1981 lease sale to first production, with no significant regulatory delays. MOEPSI took nine years from first discovery to first production, after a ten year regulatory delay. These lead times match Alaska petroleum project lead times. The frontier nature of the Norphlet geology and the associated production engineering and technology challenges closely substituted for the challenges of Alaska's harsh, remote locale. Only the major oil and gas companies could afford the billions of dollars and years of investment necessary to bring the Norphlet into production.

6.5.4 Remaining Recoverable Reserves by Field

Cumulative Norphlet production through year end 1997 totals 1.7 TCF. Shell's Fairway Field and Mobil's 823 Field, both of which initiated production in 1991, have produced the most, over 325 BCF each. Table 6.15 shows that Fairway's 1996 cumulative production amounts to 38 percent of discovered gas in place (GIP); 823 Field 1996 cumulative production amounts to 23 percent of GIP. Fairway Field was shown on Figure 6.9 to have been in decline since mid-1994. Shell, sizing plant and equipment to peak, produced approximately 20 percent of GIP on peak before natural decline set in. Mobil and Exxon, by comparison, have sized plant and equipment to sustain a flat production rate longer, and have produced a substantially lower percentage of discovered reserves over comparable lengths of time. Nonetheless, some wells in 823 are showing signs that natural decline set in during 1996. If so, the 823 Field decline set in at about the same 20 percent of produced GIP as Shell.

Discovered state reservoirs are shown on Table 6.15 to be generally larger than federal reservoirs. Between 4 - 4.4 TCF state recoverable reserves remain. Between 1.3 - 1.9 TCF federal recoverable reserves remain at year end 1996. These GRI estimates are in line with, but somewhat larger than AOGB and MMS estimates shown in Section 2.1. Reserve estimates tend to differ among practitioners.

The 1997 average production rate, 1.02 BCFD, results in a remaining reserve to production ratio (R/P) at year end 1996 of 14 to 17. This is in line with the R/P calculated with AOGB and MMS reserve estimates in Section 2.1, which was 13 - 19. Shell, which has produced their field at the highest recovery rates, has the lowest R/P, 4 - 8. Fairway Field production in 1997 amounted to 56 percent of peak year 1993 production.

Table 6.15
Remaining Recoverable Reserves by Field: Year End 1996
(BCF)

Field	Cumulative Production 12/96	Discovered Gas in Place	Percent Produced 12/96	Remaining Recoverable at 75%	Remaining Recoverable at 55%
Fairway	290	765	38%	284	130
Mary Ann	237	1,400 (excl 95-5 GIP)	17%	813	533
Northwest Gulf	171	1,125	15%	673	448
Bon Secour Bay	102	1,335	8%	899	632
North Central Gulf	98	985	10%	641	444
State 109	3	20	15%	12	8
Aloe Bay	0	1,500	0	1,125	825
Total State	**901**	**7,130**	**13%**	**4,446**	**4,020**
823	297.8	1,325	23%	696	431
821	35.6	125	29%	58	33
827	23.4	275	8%	183	128
916/961	38.2	715	5%	498	355
861	9.4	55	17%	32	21
868	0	315	0%	236	173
904	5	170	3%	123	89
872	3.5	185	2%	135	98
820/864	2.4	>200	1%	148+	108+
Total Federal	**415.3**	**3,365+**	**12%**	**2,109+**	**1,436+**

Source: Production from Tables 6.13 & 6.14; Reserve estimates from GRI, MMS and industry contacts.

6.5.5 Norphlet and Miocene Platforms

A total of 39 fixed structures and platforms are located in Alabama state waters. Twenty five of the structures are platforms; the remainder are single well caissons. Table 6.16 summarizes the types of platforms located in each field by operator. MOEPSI initiated production from the first platforms installed in 1988. Six of the seven structures installed in 1991 are operated by Shell, with the remaining platform operated by Callon Petroleum (originally owned and installed by ARCO). Exxon installed 11 platforms and caisson wells in preparation for first production from its three state fields in 1993.

The number of structures installed on the Mobile OCS near Alabama waters to support production totals 44, comprised of platforms and well caissons. Table 6.17 summarizes the number of structures installed in each field by operators within the Mobile Area OCS. The first Mobile OCS platform was installed by Chevron on Mobile Block 861. The next to be installed was also by Chevron in 1987 on Mobile Block 862.

Table 6.18 shows annual platform installation for Mobile OCS waters compared to those placed in Alabama state waters since 1979.

6.5.6 Forecast of Mobile Bay Gas Development & Production

The forecast for gas production in Coastal Alabama, including total Miocene and Norphlet gas production through 2010, is shown on Table 6.19 along with 1996 and 1997 actuals. Norphlet production for 1998 will increase 10 percent over 1996 levels. Miocene production is declining. Coastal Alabama production will increase about ten percent annually for each of the three years, 1998 - 2000. Destin Dome will supplant declining Coastal Alabama after 2001, and sustain Norphlet production levels above or near 1.4 BCFD through 2005.

To create Norphlet production estimates for 1998 and beyond, wells in production in December, 1997 plus the wells on Table 6.11 that have advanced beyond the planning stages are assumed to be added to existing reservoirs, produce 30 percent of discovered GIP on peak, and then decline at rates of between six and twelve percent annually until between 55 - 75 percent of GIP is produced. (See Table 6.15 for GIP.) The new wells (which are delineation and development wells) are assumed to be successful, and produce at an average rate of 33 MMCFD. Varying decline rates for different fields are specified based on historic and current production data, reserve estimates, and miscellaneous operator intelligence. Production forecasts for Chevron's Destin Dome unit were furnished by the operator.

Miocene production averaged 98 MMCFD for 1997, down from 125 MMCFD for 1996 and 150 MMCFD in 1995. The decline in state and federal fields is assumed to continue at a rate of ten percent annually. No significant new Miocene production has been announced.

Mobile Bay region Norphlet production will rise to near-peak levels of over 1,300 MMCFD (annual average) in 2000. The region's gas treatment capacity of approximately 1,520 MMCFD (excluding forthcoming Destin Dome capacity) may be utilized near capacity during the winter, 1999-2000 and forthcoming years. After 2002, existing Mobile Bay Norphlet production will

Table 6.16
Offshore Structures Located in Alabama State Waters

Offshore Field	Operator	Type of Platform	Installed
Bon Secour Bay	Exxon	Well Platform (1)	1993
		Bridge-Connected Well Platform (1)	
		Production Platform (1)	1993
Fairway	Shell	Well Platform (4)	1991
		Bridge-Connected Well Platform (1)	1991
		Production Platform (1)	1991
Goose Bayou	Legacy	Single Well Caisson (1)	1995
Lower Mobile Bay — Mary Ann	Mobil	Well/Production Platform (4)	1988
		Bridge-Connected Well/ Production Platform (1)	1988
		Production Platform (1)	1988
North Central Gulf	Exxon	Well Platform (1)	1993
		Bridge-Connected Well Platform (1)	1993
		Production Platform (1)	1993
North Dauphin Island	Callon Petroleum	Production Platform (1)	1991
		Single Well Caissons (5)	1991
Northwest Dauphin Island	Offshore Group	Production Platform (1)	1994
		Single Well Caissons (3)	
Northwest Gulf	Exxon	Well Platform (2)	1993
		Production Platform (1)	1993
		Bridge-Connected Living Quarters Platform (1)	1993
		Bridge-Connected Well Platform (1)	1993
Northeast Petit Bois Pass	Offshore Group	Single Well Caisson (1)	1994
South Dauphin Island	Scana	Single Well Caissons (3)	1992
East Mississippi Sound	Legacy	Production Platform (1)	1995
		Single Well Caisson (1)	

Source: AL Oil and Gas Board, 1997.

Table 6.17
Platforms and Caissons in Mobile OCS Waters

Field Name/ Block Number	**Operator**	**Structure Name**	**Year Installed**
MO821			
821	BP	A-QUARTERS	1991
MO823			
822	Scana	A	1993
822	MOEPSI	B	1994
823	MOEPSI	A	1991
MO827			
827	Exxon	CB	1992
MO861			
861	Chevron	A	1985
861	Chevron	AB	1991
MO864			
863	Chevron	#2 CAISSON	1990
863	Chevron	A	1994
864	Chevron	A-5064	1991
864	Chevron	BA(#3)	1994
864	Chevron	B	1995
864	Chevron	BQ	1995
908	Chevron	A-5071	1991
908	Chevron	SAT. #2	1991
MO865			
865	Scana	#3	1994
MO866			
822	OEDC	A	1993
822	OEDC	B	1994
MO868			
868	MOEPSI	A	1992
869	MOEPSI	A	1990
MO870			
870	Enron	#2 PLAT.	1988
870	Enron	A	1994
MO872			
872	Chevron	#1 CAISSON	1996

Table 6.17 (continued)
Platforms and Caissons in Mobile OCS Waters

Field Name/ Block Number	**Operator**	**Structure Name**	**Year Installed**
MO904			
904	Unocal	AP	1993
904	Unocal	AQ	1993
904	Unocal	AW	1993
MO914			
914	Enron	A	1994
MO916			
916	Unocal	#1 CAISSON	1987
916	Unocal	#2	1991
916	Unocal	AP	1994
916	Unocal	AQ	1994
916	Unocal	B	1994
MO945			
945	Apache	#1 CAISSON	1990
MO947			
947	Apache	#1 CAISSON	1990
MO952			
952	Murphy	#1	1992
953	Murphy	#1	1992
MO955			
955	Murphy	#2	1992
MO959			
915	OEDC	#1 CAISSON	1988
959		A	1994
MO960			
960	OEDC	A	1995
MO961			
917	Unocal	A	1994
961	Unocal	#1 CAISSON	1987
MO990			
990	Apache	#1 CAISSON	1990
990	Enron	A	1991

Source: US DOI MMS, 1998.

Table 6.18
Mobile Bay Offshore Structure
Installations by Year

	State	Federal
1985	0	1
1986	0	0
1987	0	2
1988	6	2
1989	0	0
1990	0	5
1991	12	8
1992	3	5
1993	11	5
1994	5	12
1995	2	3
1996	0	1
Total to 1997	**39**	**44**

Sources: US DOI MMS, 1998; AL Oil & Gas Board, 1997.

Table 6.19
Mobile Bay Offshore Gas Production Forecast
Annual Average (1996 - 2010)
(MMCFD)

	Year	Norphlet				Miocene			Total Gas Production
		Coastal Alabama		Destin Dome	Total Norphlet	Coastal Alabama		Total Miocene	
		Alabama State	Mobile OCS			Alabama State	Mobile OCS		
HISTORY	1988	26	-	-	**26**	0.5	-	**0.5**	**26**
	1989	35	-	-	**35**	0.4	-	**0.4**	**36**
	1990	55	-	-	**55**	-	-	-	**55**
	1991	90	7	-	**97**	0.5	1.7	**2.2**	**99**
	1992	254	159	-	**414**	55	76	**131**	**545**
	1993	313	151	-	**464**	48	87	**134**	**598**
	1994	585	225	-	**809**	47	103	**149**	**959**
	1995	555	269	-	**824**	32	120	**152**	**976**
	1996	548	298	-	**846**	29	97	**126**	**972**
	1997	581	423	-	**1,004**	11	77	**88**	**1,092**

Source: Foster Associates, 1998.

begin a slow decline, falling below 900 MMCFD by 2008, if no other reserves are brought on line. The addition of Chevron's Destin Dome production in 2001 will sustain peak regional production levels for five years over 1.4 BCFD into 2005.

Production of natural gas from the Destin Dome Area located in the Eastern Gulf of Mexico is shown on Table 6.19. Destin Dome gas production will start up in 2001 with estimated production of 42 BCF, or 115 MMCFD, that year. Destin Dome gas production is projected to reach peak at 110 BCF in 2004, producing 300 MMCFD, and to remain on peak for seven years. By 2004, Mobile Bay production (excluding Destin Dome) will have declined to about 1,210 MMCFD from its 2000 - 2001 peak near 1,400 MMCFD. Destin Dome's contribution to total Mobile Bay regional production is shown on Figure 6.16. Destin Dome production will account for a quarter of total regional Norphlet production after 2005.

Combining both the Alabama state and federal OCS baseline offshore production, the forecast for total offshore production in the area is shown on Figure 6.16. This figure plots monthly production data. Coastal Alabama and Florida natural gas production will rise to 1.4 BCFD in 2000 and remain above 1.4 BCFD through 2005—with no more discoveries. The forecast on Figure 6.16 yields over 9.5 TCF cumulative production of Norphlet and Miocene by 2015.

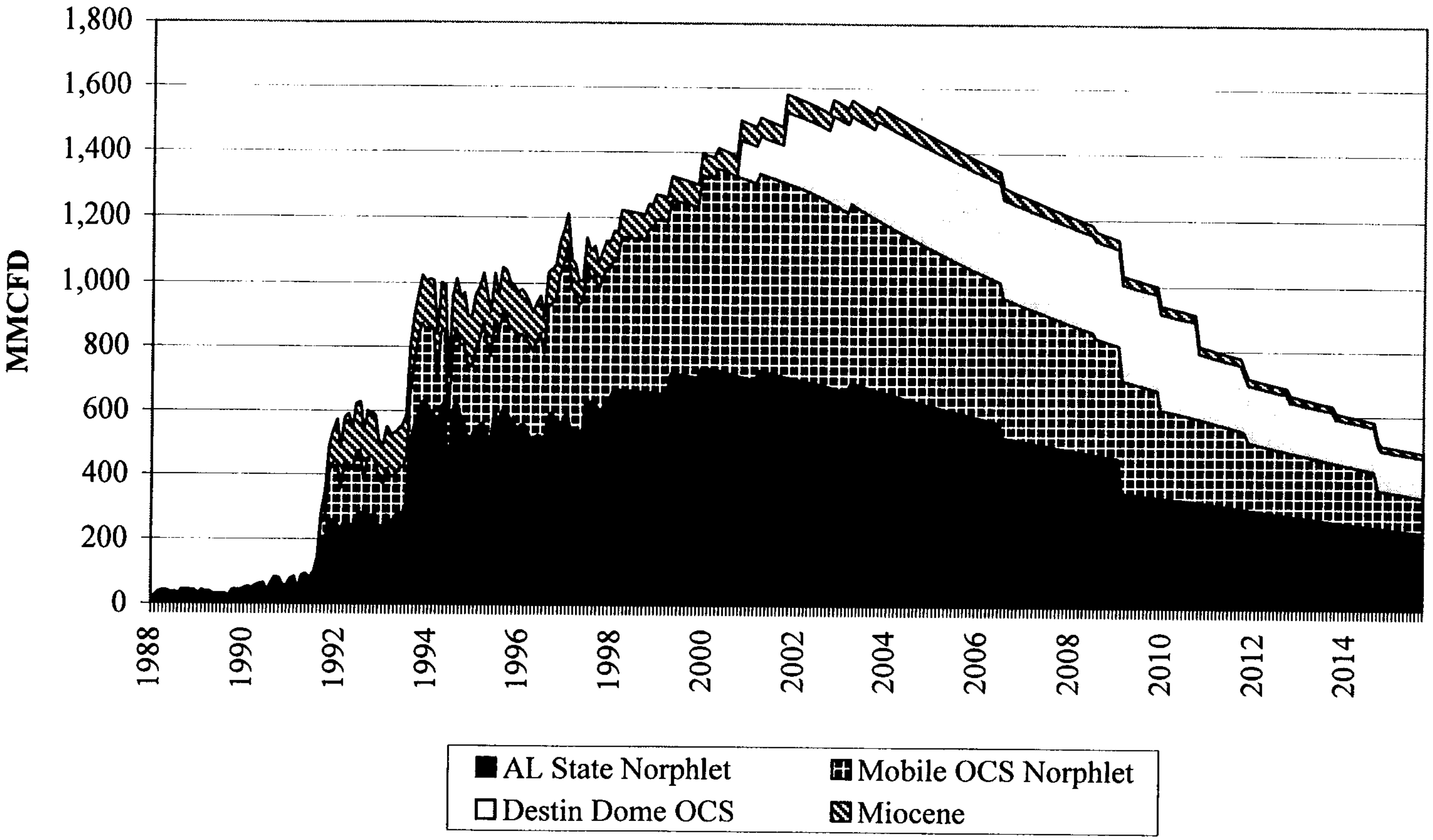


Figure 6.16. Mobile Bay Offshore Gas Production History and Forecast.

Source: Foster Associates, 1998.

APPENDIX

Offshore Gas Forecast Reserve and Decline Rate Assumptions

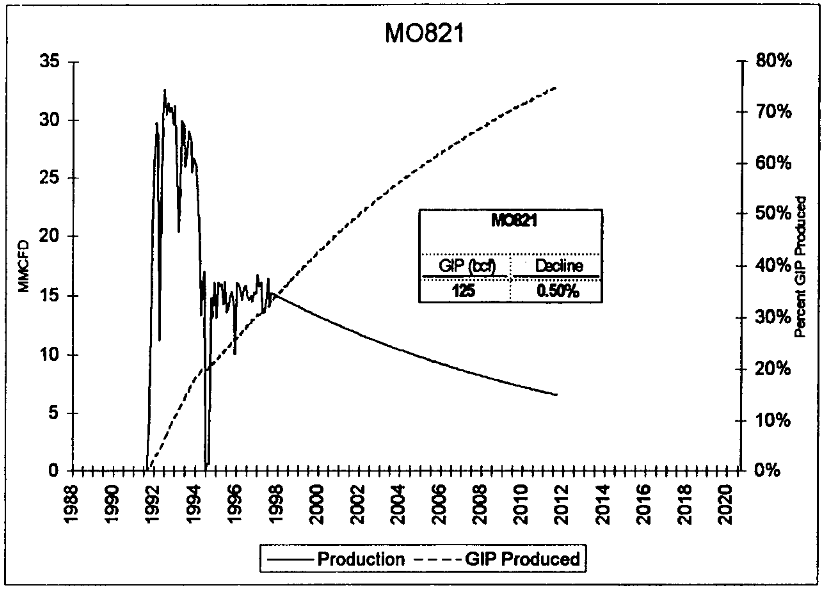
Post -1997 Well Startups Assumed in Mobile Bay Gas Production Forecast

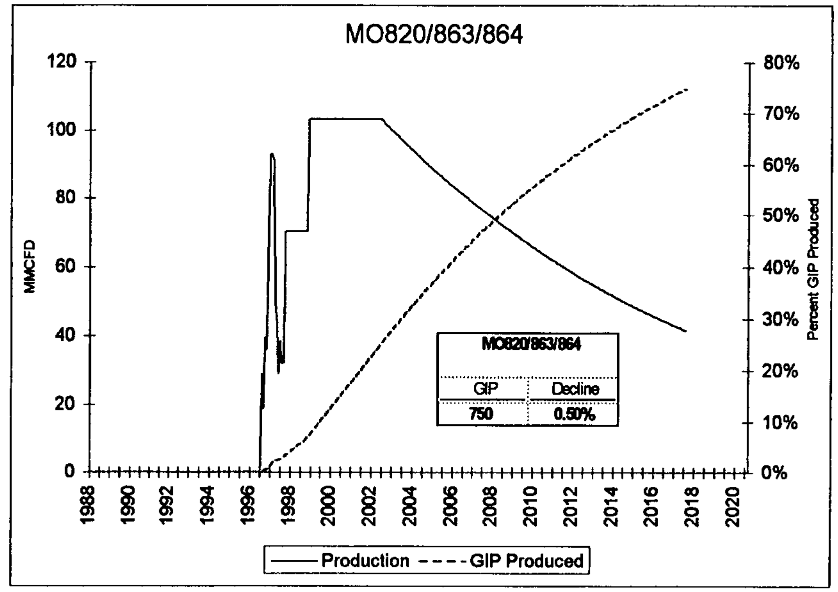
Field Name	Well No.	Startup Date	Production Rate (MMCFD)
Al State			
North Central Gulf	114-3	Feb-98	33
Aloe Bay	75-2	Jul-99	33
Bon Secour Bay	61-1	Jul-99	33
Mary Ann	95-4	Mar-00	33
Aloe Bay	75-3[1]	Jun-01	33
Aloe Bay	75-4[1]	Jun-03	33
Federal			
MO820	819-1	Jan-98	22
MO864	864-4	Dec-97	16
MO823	823-A5	Jun-98	33
MO914	914-4	Jul-98	33
MO861	862-1ST	Jan-99	33
MO864	863-4	Mar-99	33
MO870	870-1	Mar-00	33
MO918	918-1	Mar-00	33
MO871	871-1	Jun-00	33
Total New Wells Through 2001		**15**	**467**

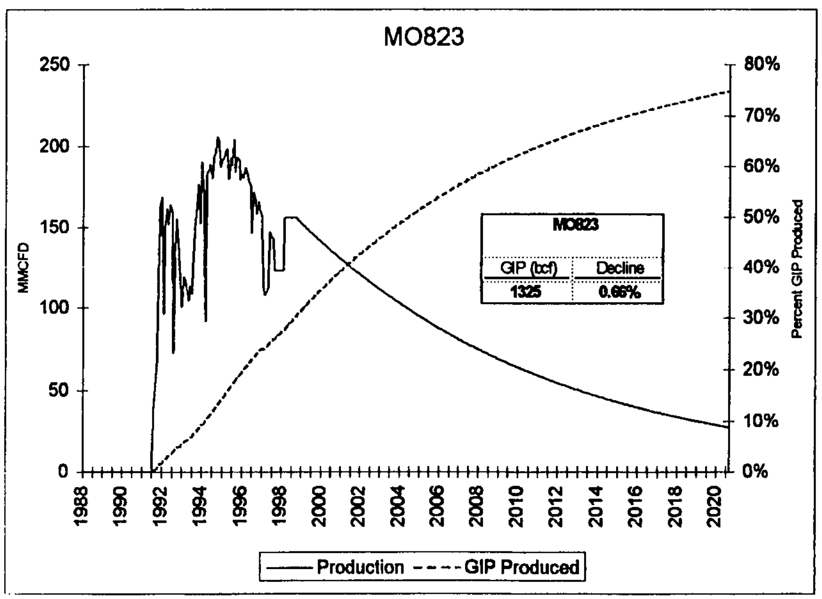
Source: Telcons with operators.

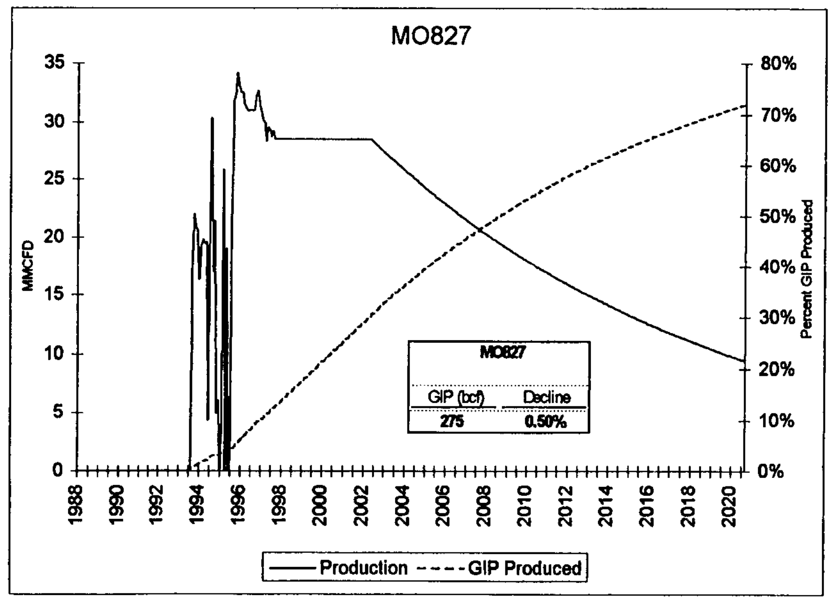
[1] A new well is assumed at some point in the future to utilize large proved reserves in this field.

Offshore Gas Forecast Reserve and Decline Rate Assumptions









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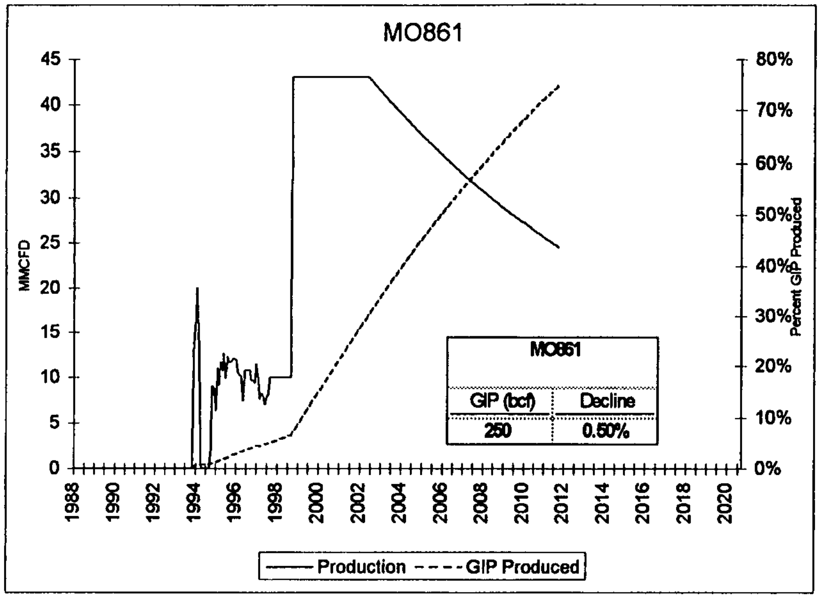

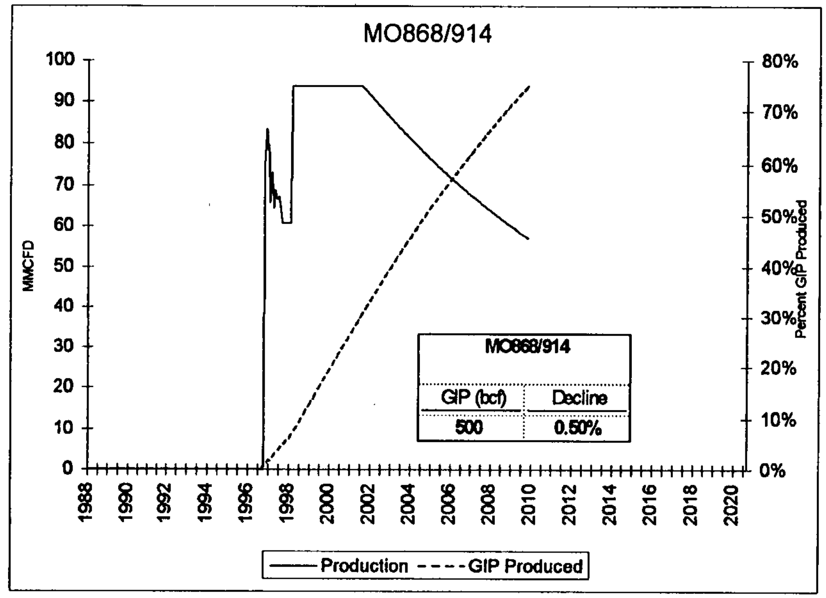

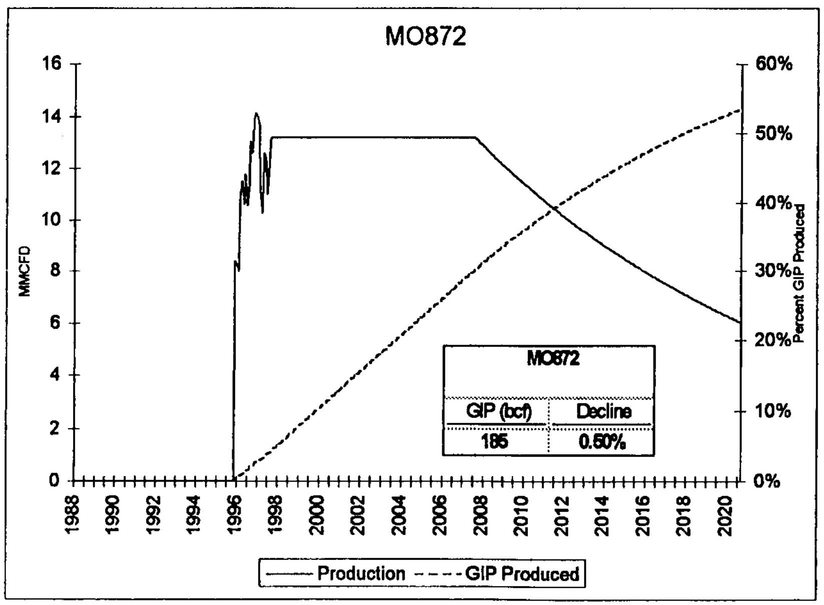

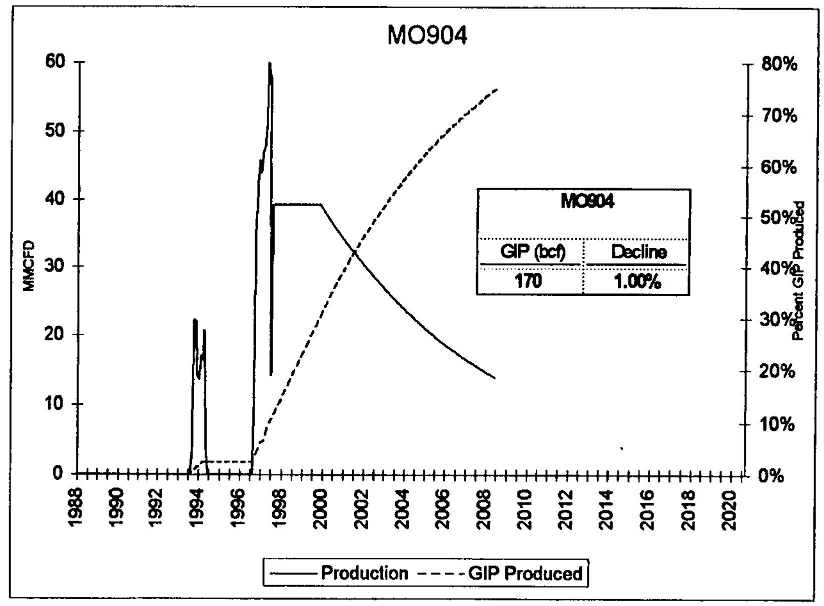

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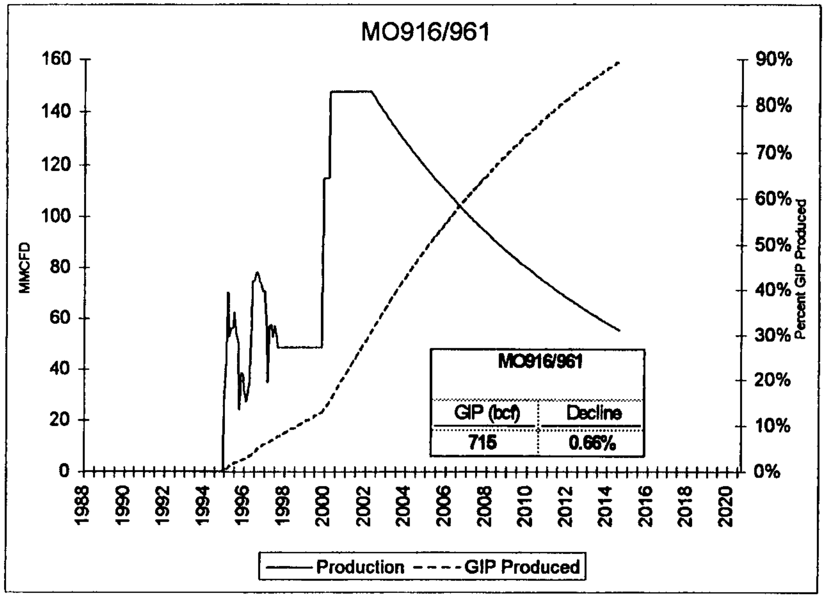

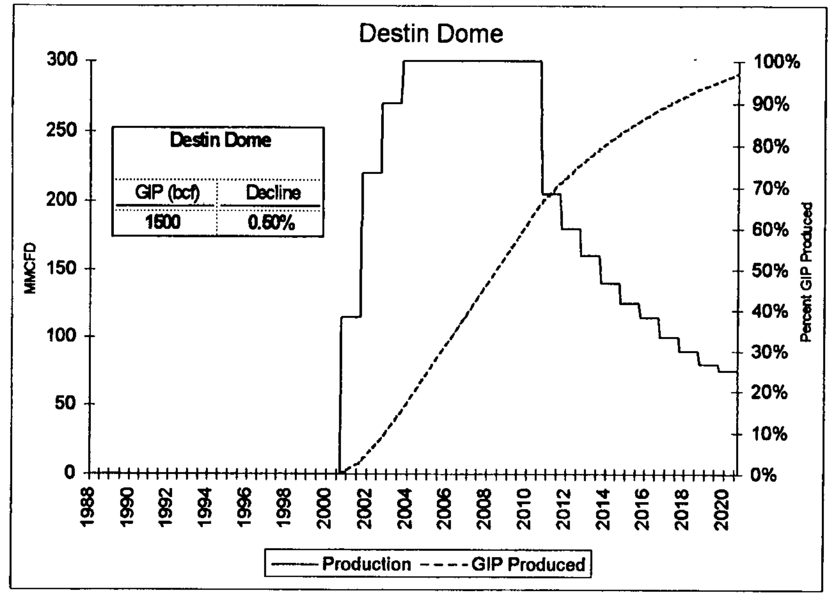

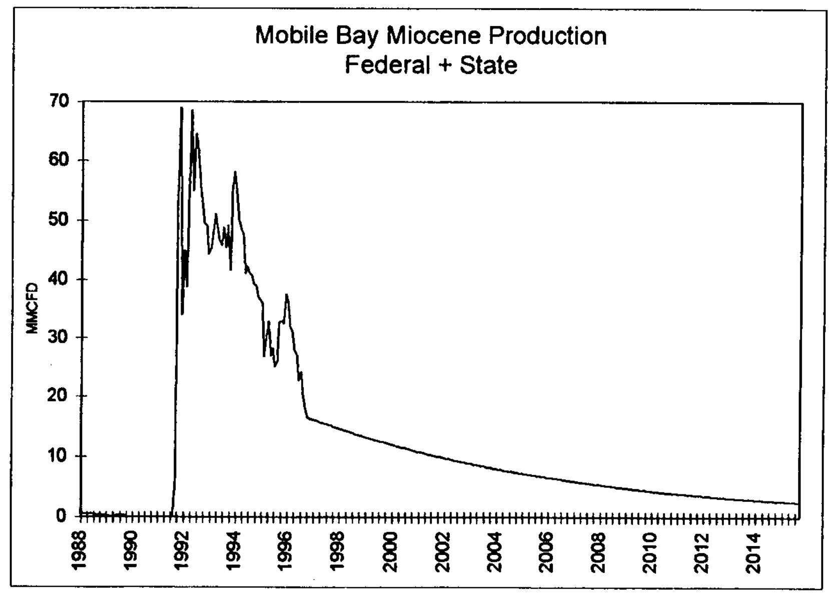

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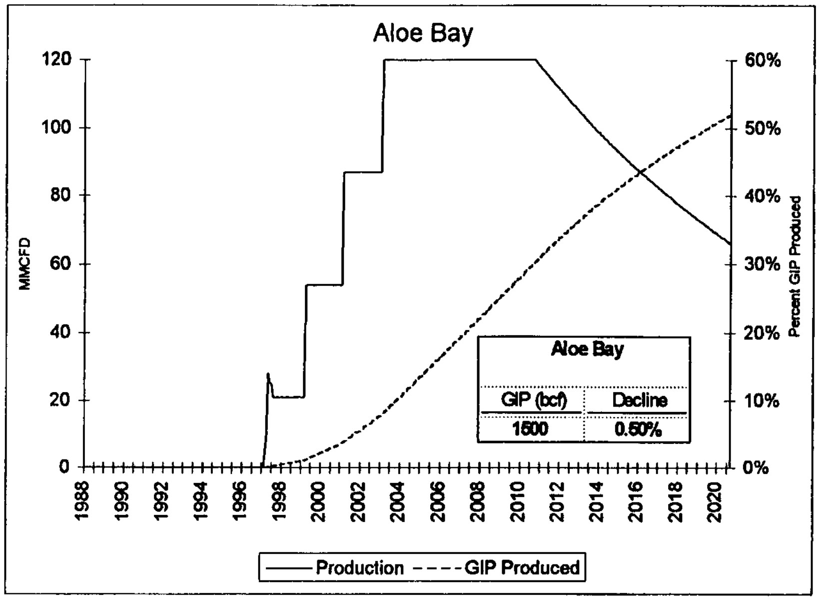

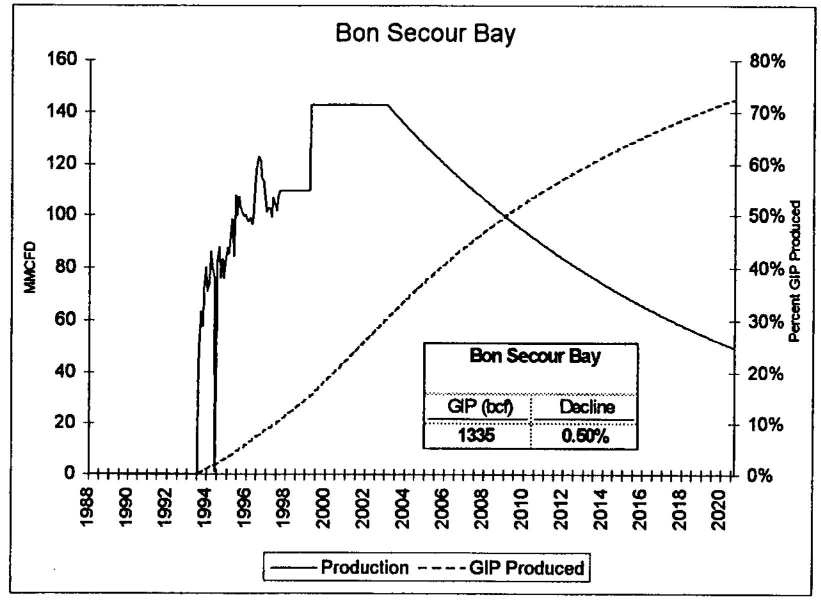

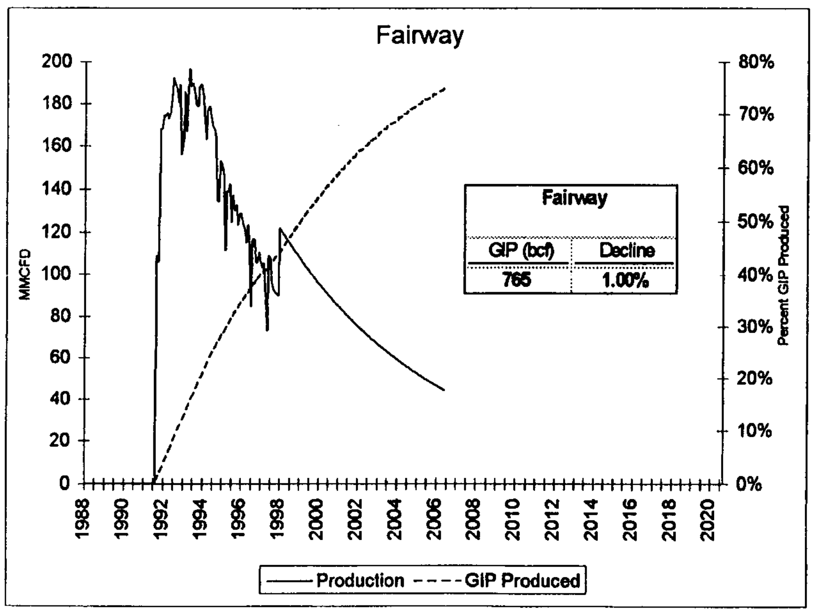

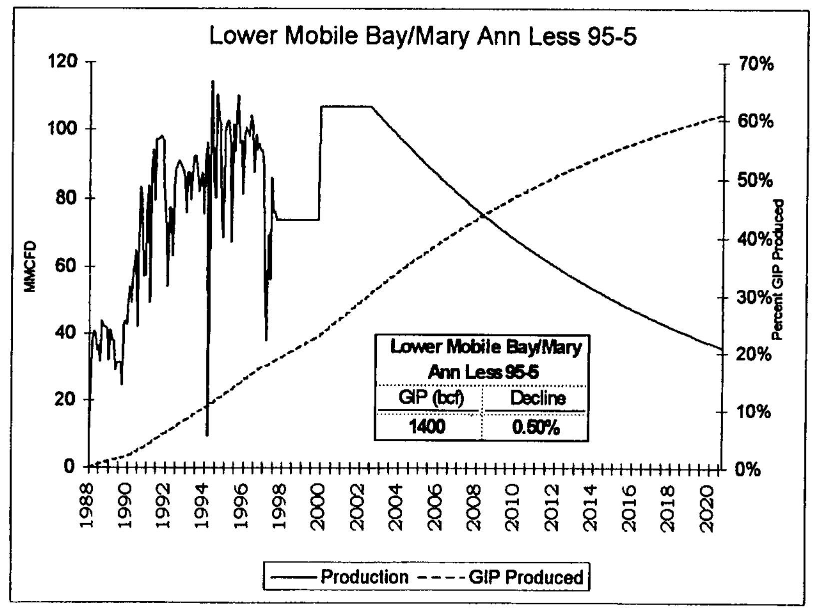

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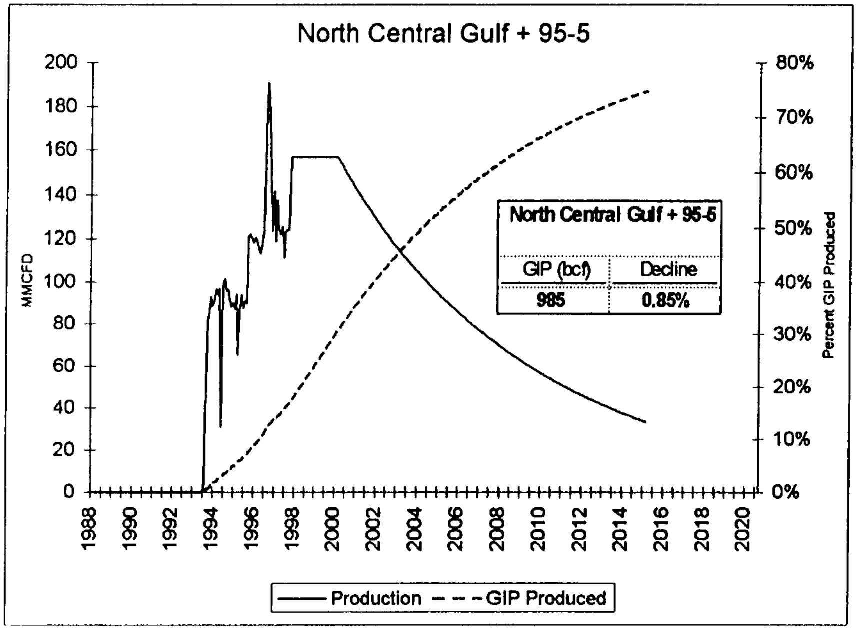

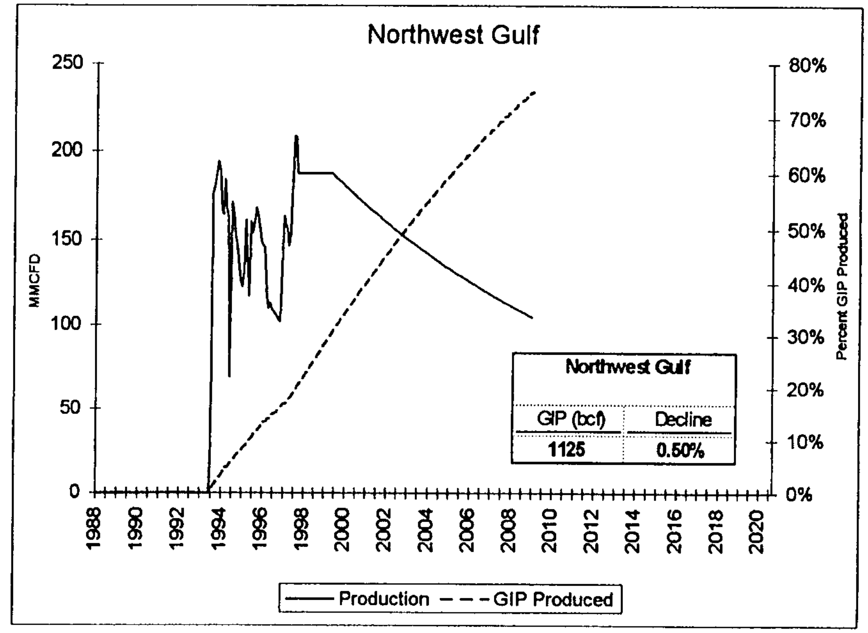

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9-6-86
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7-17-964
4-14-929
12-13-90165
11-9-933
2-6-924

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.