Section 3

My name is Jack Blomstrom. I am testifying today on behalf of Eighty-Eight Oil Company (88) of Casper, Wyoming. 88 is a crude oil marketing company engaged in purchasing crude oil, primarily at the lease. Its operations are conducted primarily in the northern Rocky Mountain area. We do not post.

88 is affiliated by ownership with True Oil Company, an oil and gas exploration and production company.

As Mr. Schaeffer said any active exploration and production company is regularly engaged in buying frac oil for their own operations.

88 purchases most of True Oil Company's production though the percentage of affiliated companies' production to the total amount of crude oil purchased by 88 is very small.

However, because of its purchase of production of affiliated companies, 88 has a very broad ranging interest in the proposed valuation rules for royalty production owned by the federal government.

First, 88 fully supports the comments of Mr. Ben Dillon delivered earlier on behalf of IPAA. Frankly, we fully support the bulk of the statements which you will hear today. We are especially concerned that these proposed regulations, if implemented, will result in independents paying royalty on phantom proceeds.

I want to briefly discuss the way the proposed regs will affect both affiliated sales and sales by non-affiliated companies.

From an affiliate's perspective, the proposed regulations suggest 88/True Oil Company will have two options to determine royalty value. One is to use the marketing affiliate sales price to an arms-length purchaser. The second is to use the alternative NYMEX method.

Realistically, 88 can't use its sales, because under the proposed regulations, it would be disqualified from doing so because it both purchases and sells crude oil. We also would be disqualified because we cannot track every single barrel of oil to know exactly what its selling price was. Hence we get the NYMEX proposal.

Because of where 88 operates, one special example contained in the proposed regulations was especially interesting. On page 3748 of the January 24, 1997, FEDERAL REGISTER was the following example:

> "If you do not move lease production through a MMS-identified aggregation point to a MMS-identified

market center, but instead move it directly to an alternate disposal point (for example your own refinery), then you would use only two of the adjustments and allowances. You would use the market center-index pricing point location/quality differential under paragraph (c)(1)(iv). In this event, the alternate disposal point is the aggregation point for purposes of that paragraph. The market center for purposes of paragraph (c)(1)(iv) is the market center nearest the lease where there is a published spot price for crude oil of like quality to your oil. Like-quality oil would mean oil with similar chemical, physical, and legal characteristics. For example, West Texas Sour and Wyoming Sour would be like-quality, as would West Texas Intermediate and Light Louisiana Sweet.

For example, a Wyoming Sour crude producer might transport its oil directly to a refinery in Salt Lake City without accessing any defined aggregation points or market centers. In this case, West Texas Sour crude at Midland, Texas, might represent the crude oil/market center combination nearest to the oil produced. The market center-index pricing point location/quality differential under paragraph (c)(1)(i) would then be the difference in the spot price between West Texas Intermediate at Cushing, Oklahoma, and West Texas Sour at Midland, Texas, as published in an MMS-approved publication. In addition to that adjustment, the producer would be entitled to an allowance for the actual transportation costs from the lease in Wyoming to Salt Lake City. MMS has determined that this method is the best way to calculate the differences in value between the lease and the index pricing point due to location, quality, and transportation when the production is not actually moved to a market center."

We have several concerns with this example. First, it demonstrates a lack of market awareness by the MMS, because virtually no Wyoming Sour currently makes its way to the Salt Lake City market.

Second, there is little, if any, similarity in West Texas (WT) Sour and Wyoming Sour other than the fact both contain sulfur. They are sold in totally different markets. WT Sour averages - as I understand it from industry information, 1.9% sulfur. WY Sour averages closer to 2.4%. WT Sour has an average gravity of 34°. WY Sour is classified as either Wyoming General Sour or Wyoming Asphatlic Sour. The General Sour has gravity of from 22° to 28°. That represents a mid-point of 25.5°. The Asphatlic Sour which

represents the overwhelming percentage of Wyoming Sour production is 20° to 22°. The gravity differential alone, which is not considered in this example at all, between WT Sour and WY Asphatlic would be $2.40/bbl. It would seem that if the MMS values its royalty oil without factoring in the gravity differential, it will receive a windfall, otherwise known as phantom proceeds.

A factor to be considered is that the differential to be used will remain in effect for one year as I read the proposed regulations. Yet consider the Wyoming market for sour crude.

As we speak, Canadian crude is beginning to move through Casper, WY. Because of market conditions elsewhere, the crude in Express will be primarily sour crude. Express will, if all goes as it has indicated, be bringing 175,000 bbl of crude into Casper. It will ship 135,000 bbl of crude east to Wood River, Illinois, on Platte Pipeline. That is each day. The 40,000 surplus bbls. each day will compete for existing markets, because there doesn't appear to be any place else to go. Three refineries in Wyoming, one in Denver and one in Salt Lake City can take sour crude. How will this effect the existing market? No one knows. Yet, under these regulations as proposed, for our affiliates' production, we would be using the same differential for an entire year. Given the market situation, that makes no sense.

For affiliates with both production and marketing operations, the current regs work well. We don't post and do not intend to in the future. Please leave well enough alone. What is in place now, when applied to 88 and True Oil, is not broken.

Let me briefly discuss another aspect of 88's business. We purchased 850K bbl in January of the crude oil at the lease. In every sense, the transactions are arms length. Yet, under the proposed regulations, because our customers are invariably buying frac oil for their lease operations, or because they have purchased some properties from a major which included a call on production provision in the sales contract, these transactions will no longer be considered arms length.

Why is MMS replacing these arms length transactions with a single price NYMEX netted back to scores of wellheads in the northern Rocky Mountain states?

Parenthetically, you earlier heard Amy Siebel of Nance Petroleum talk about their experience with calls on production. In reviewing True Oil Company's records, we did not discover a single instance of where a party was exercising its right to a call on production.

Now, our customers, primarily small independents, will be stuck valuing their oil for royalty purposes at a location away from where they are selling their oil, the wellhead.

I recently saw a copy of a letter from the director of the MMS to the editor of BUSINESS WEEK. In the letter, the director said, and I quote:

> "The proposed rule would not change the long standing policy to base royalty valuation on the wellhead price."

From what I have seen in the proposed regulations, that simply is not the case.

Many of our customers have had long term relationships with SS. Why, because we have consistently given them fair value for their crude oil. If they could get more for their crude consistently elsewhere, we have no doubts they would no longer be our customers, they would be somebody else's.

We, along with our customers, can figure out an arms length value at the lease. Why can't MMS?

Many of our customers do not want to take on the risk involved in marketing their own crude. They already are absorbing the risk of discovering and production oil. Look at a sample example. Crude purchase contracts at the wellhead may involve an average purchase price for the month.

January price was around $23.50. As a marketer, you are faced with the possibility of carrying an inventory from one month to the next. If you carried inventory from January into February, you would have been faced with a price over $3.00 a barrel less in February than in January. Certainly prices could have gone the other way but they didn't. Yet, in these proposed regulations, MMS wants federal government lessees to give the MMS the benefit of that marketing risk, without any downside.

If you want the upside, you need to get into the market, take your oil in kind, and market yourself.

From our perspective, it is abundantly clear that MMS has the tools currently to collect a fair royalty. Use what you have.

Why reject the 1988 regulations currently in effect? Look to gross proceeds. It works.

Thank you.

Section 4

Sales Locations and Typical Terms

"Lease Activity"

- **The first point of sale for most domestic crude is at the lease**
- **Significant portion of activity is between 3rd parties**
- **Posted prices are the predominate pricing basis**
- **Typical Terms:**
  - Guarantee lifting
  - Long-term commitment
  - Volume as produced
  - Quality as produced
  - Then-current market price (priced on *day-of-delivery*; forward pricing is not used)

Section 5

U.S. CRUDE MARKETS AND VALUES

Presented to Minerals Management Service

August 1996

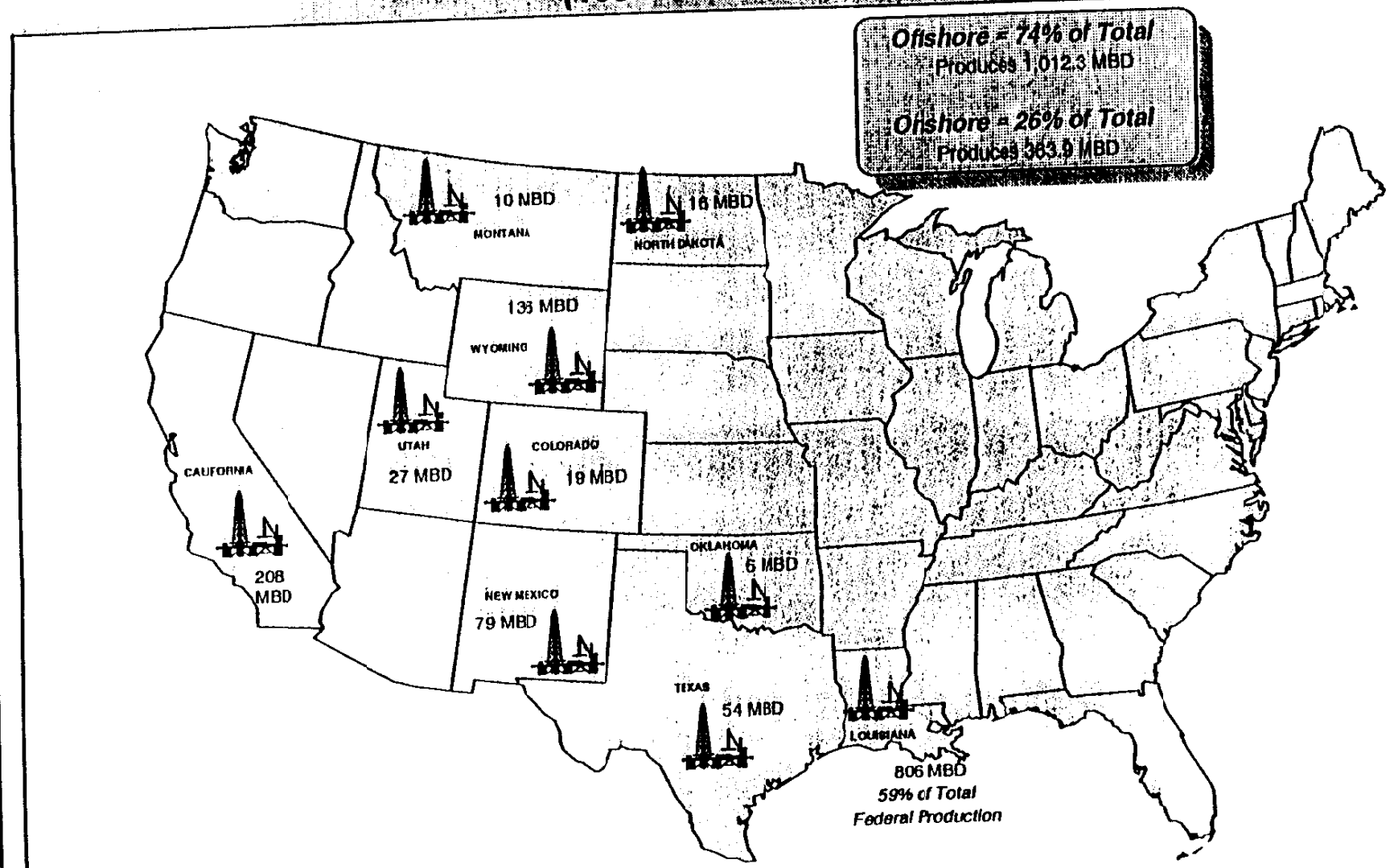
Micronomics, Inc.

400 South Hope Street
Suite 2500
Los Angeles, CA 90071

300 Capitol Mall
Suite 1460
Sacramento, CA 95814

1201 New York Avenue, N.W.
Suite 530
Washington, D.C. 20005

TOP TEN PRODUCING STATES ACCOUNT FOR MORE THAN 99 PERCENT OF FEDERAL VOLUMES
(1994 Production)

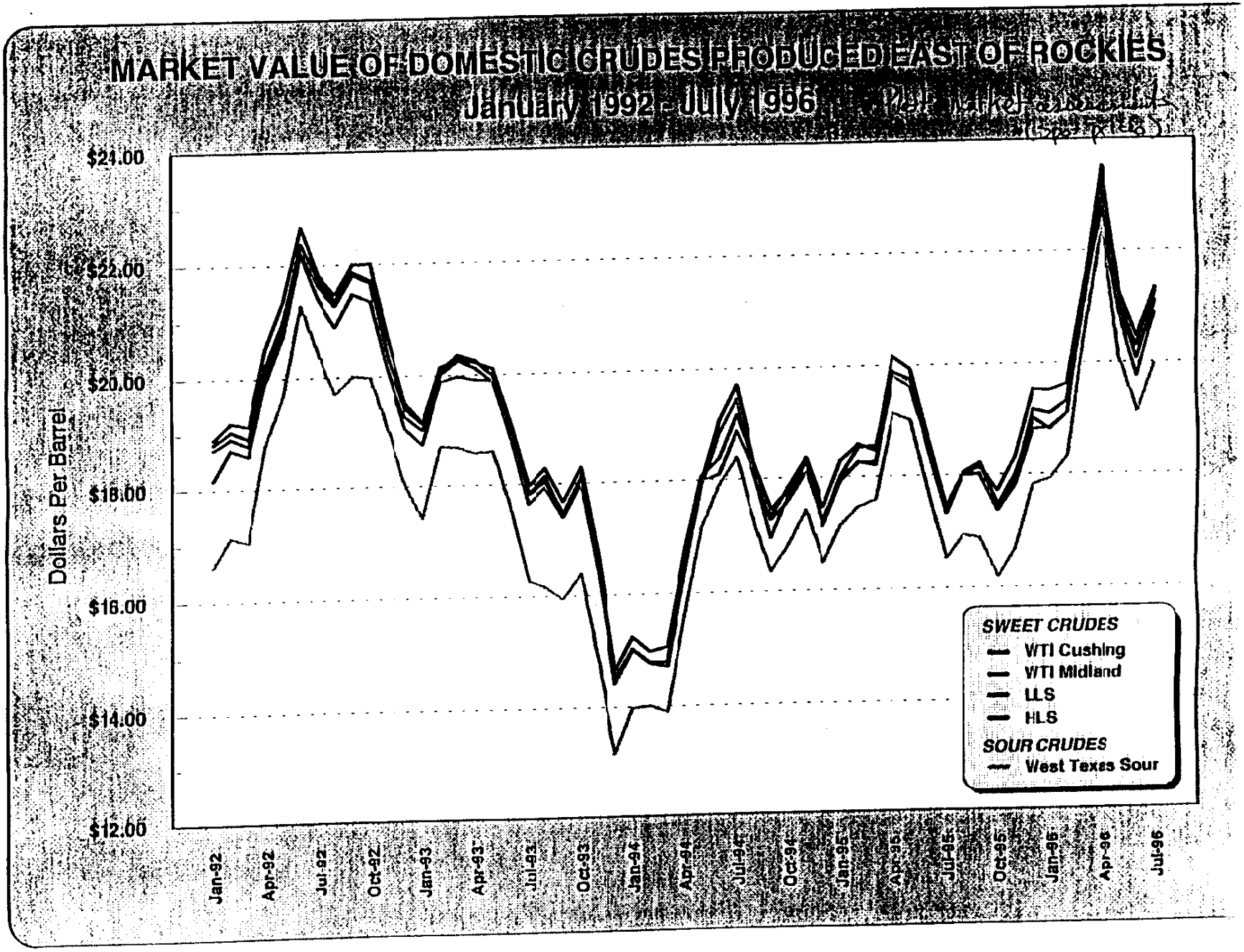


Geographic Crude Markets

- Geographic areas within markets are characterized by:
  - Common supply/demand conditions
  - Free flow of crude and refined products within each market
- Separate geographic markets have:
  - Little movement of crude and refined products between markets
- There are two geographic markets:
  - West Coast
  - East of Rockies

Market Value of Crudes Within the Same Market

- Market value of similar quality crudes are similar at any given location
- Differences in market value between different crudes within the same market result from differences in delivery location and quality
- Market value of crude at lease can be determined based on market value of widely traded crudes within the same market adjusted for quality and location differences

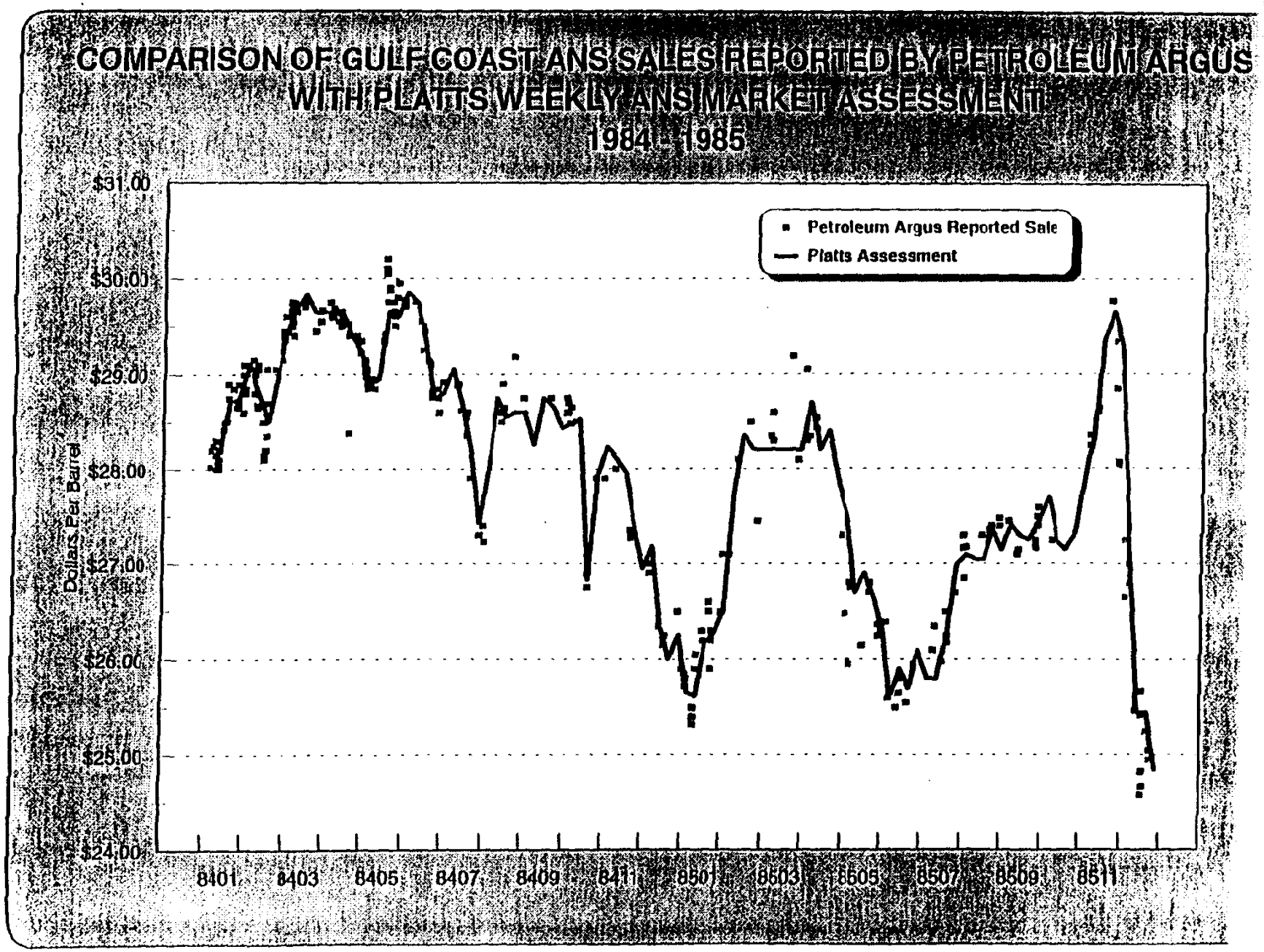

MARKET VALUE OF DOMESTIC CRUDES PRODUCED EAST OF ROCKIES
January 1992 - July 1996
Dollars Per Barrel
$24.00
$22.00
$20.00
$18.00
$16.00
$14.00
$12.00
Jan-92
Apr-92
Jul-92
Oct-92
Jan-93
Apr-93
Jul-93
Oct-93
Jan-94
Apr-94
Jul-94
Oct-94
Jan-95
Apr-95
Jul-95
Oct-95
Jan-96
Apr-96
Jul-96
SWEET CRUDES
WTI Cushing
WTI Midland
LLS
HLS
SOUR CRUDES
West Texas Sour

Measures of Value

- Market Assessments (e.g., Platt's)
- NYMEX Light Sweet Contract
- Posted Prices
- Postings Plus

Market Assessments

- Assessments based on current market activity
- Published for a number of crudes / locations --
  Sweet / Intermediate / Sour -- Texas / Louisiana
- Accurate measures of current market activity.
  Evidence includes:
  - acceptance within industry
  - used to price foreign imports
  - track actual transactions
  - used in contracts


COMPARISON OF GULF COAST ANS SALES REPORTED BY PETROLEUM ARGUS
WITH PLATTS WEEKLY ANS MARKET ASSESSMENT
1984 - 1985
Petroleum Argus Reported Sale
Platts Assessment
Dollars Per Barrel
$31.00
$30.00
$29.00
$28.00
$27.00
$26.00
$25.00
$24.00
8401
8403
8405
8407
8409
8411
8501
8503
8505
8507
8509
8511

NYMEX Light Sweet Contract

- Recognized as the benchmark for crude values East of Rockies
- Recognized as accurate measure of market value for WTI at Cushing
- Tracks cash market for WTI at Cushing
- Large volume / very liquid market