PIRINC

Telephone: (212) 867-0052
Fax: (212) 972-9849

Petroleum Industry Research Foundation, Inc.

122 EAST 42nd STREET

New York, N. Y. 10168

A SEASON OF EXTREMES:

DECEMBER'S FREEZE AND JANUARY'S THAW

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I. INTRODUCTION AND SUMMARY

The record cold in December led to record prices for heating oil. The duration of the cold was historic: the Northeast experienced <u>six weeks</u> of weather that was 30% colder than normal, unprecedented, and particularly damaging for the early heating season when inventories must be kept relatively high.

The upheaval moved like a tidal wave through the market. Higher demand in the weather-sensitive markets competed for supplies with electric utilities and industrial facilities, where users unable to get incremental gas supplies switched to oil. We estimate that the abnormal cold caused distillate consumption to surge by an extra 500 thousand barrel per day in December, about 350 thousand B/D in the space heating market, more than 100 thousand B/D in the utility market, and some 50 thousand B/D in industrial and other markets. (See Section V.) At the same time Europe's cold weather reduced ready import supplies. The distribution system was stretched taut--barge capacity was fully utilized, and bad weather delayed normal delivery schedules. The cold caused operational problems at refineries, just as the supply system was most vulnerable.

Given the consumer's essential and--in the short-term--inflexible need for substantial increments of distillate oil on the one hand and the developing delivery and supply constraints on the other, the extreme price increases from mid-December to early January reflected the natural and inexorable interaction of market forces. Terminal prices for distillate in the New York metropolitan area peaked in early January at $1.10 per gallon, almost double the mid-November level. Consumer prices in the Northeast peaked at about the same time, having increased as much as 40-50% in one month.

Following December's historic cold was January's thaw, the warmest January in the Northeast in 40 years. Overall, the November-March heating season was 3% <u>warmer</u> than normal. Prices at the wholesale level responded instantly, giving back half of the increase within one week and returning to the pre-freeze price level by the beginning of February. Retail prices, which had lagged somewhat on the way up, dropped quickly from the peak, but did not return to November levels. Overall, consumers in the Northeast probably paid 10-15%, or $100-$150, more for distillate fuel oil in the 1989-90 heating season than in the year before.

This memorandum reviews the historic December, how the market reacted, and the market's performance through the end of the heating season in April. The longer perspective allows us to move away from the estimates made during the cold and use more complete data which are available only with a lag. More importantly, it allows us to see how the market worked. Consumer impact, for instance, onerous (if inevitable) at the peak, was ameliorated by the end of the season by falling prices and warmer weather. Hence, the view from the end of the season is very different from the view at the peak.

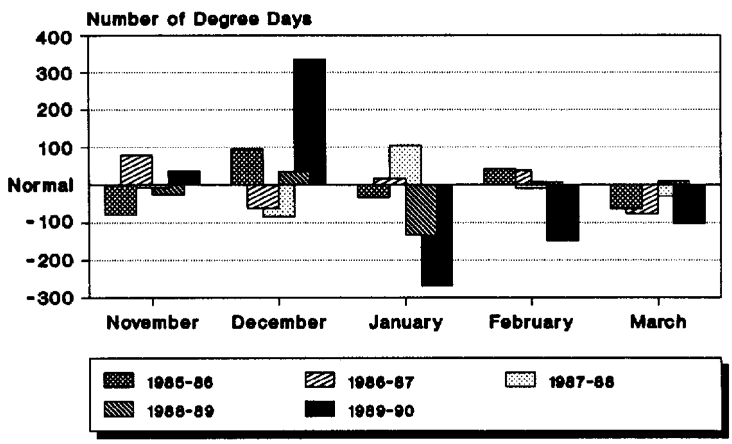
II. WHAT HAPPENED TO THE WEATHER?

Figure I illustrates that the Northeast's 1989-90 heating season was one of extremes. The '89-90 prime season (December through February), shown by the black bars, was consistently further from normal weather than other recent seasons--much colder, much warmer. Furthermore "December's" cold wave actually started in mid-November.

It is important to understand the cold was historically unique because commercial entities plan operations around normal circumstances, with a reasonable leeway to deal with contingencies. They do not plan for one-in-fifty, or one-in-one hundred market conditions. Oil companies are no different.

Figure I

Degree Days in the Northeast
Deviation from Normal



III. WHAT WAS THE SUPPLY PICTURE AT THE BEGINNING OF THE HEATING SEASON?

A. Inventories

In the last decade, changes in oil markets have dictated that companies reduce their stocks of crude and product. Stocks of distillate fuel oil followed the trend.

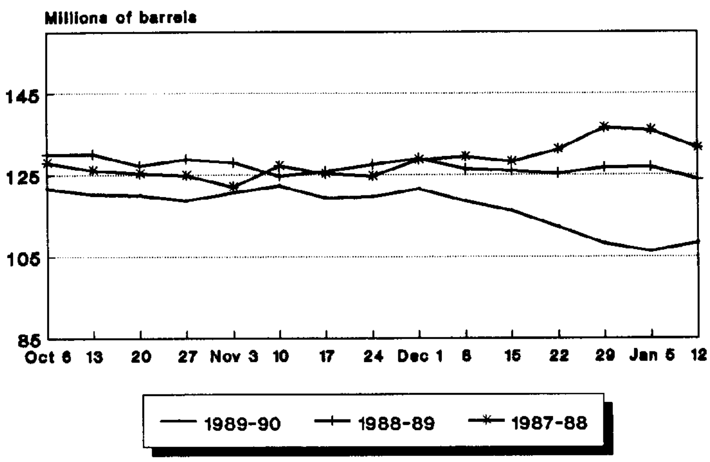
▪ *Declining demand* requires lower stocks. Residential demand for heating oil fell from nearly 1 million B/D in the mid-1970's to 500 thousand B/D in 1989.

▪ *Consolidated operations* reduce required inventories as well. One terminal with a higher utilization rate can do the work of multiple facilities. According to the National Petroleum Council's (NPC) 1988 report, *Petroleum Storage & Transportation*, the shell capacity of distillate tanks in the Mid-Atlantic and New England was 73 million barrels, down from 109 million barrels in the NPC's 1978 survey. U.S. distillate storage capacity fell to 221 million barrels, from 319 million.

As a result of these factors, it was not surprising that distillate inventories at the beginning of the 1989-90 heating season were only about half of the levels seen a decade ago. However, at 121 million barrels, end-October stocks in 1989 were just 5% below 1988 and equal to 1987 levels. Thus, they were not out of line with recent historical inventories and were definitely adequate for a moderately colder-than-normal winter. It should be pointed out in this connection that the National Weather Service's 90-day forecast published at the end of October, was predicting warmer than normal conditions over the Atlantic Coast and Northeast."

Figure II

U.S. Distillate Stocks
October - January



Source: American Petroleum Institute

The difference in stock cover, then, was not the inventory level at the *beginning* of the heating season in comparison with earlier years. Rather, it was what happened to stocks as the season progressed. As shown in Figure II, inventories in the 1988-89 season grew between end-October and end-November, and by end-December, were only 5 million barrels below the starting point. In the 1987-88 season, end-December inventories were 13 million barrels *above* the starting point. Contrast these inventory changes with the 1989-90 season when inventories had to be drawn down 2 million barrels in November and 14 million barrels in December.

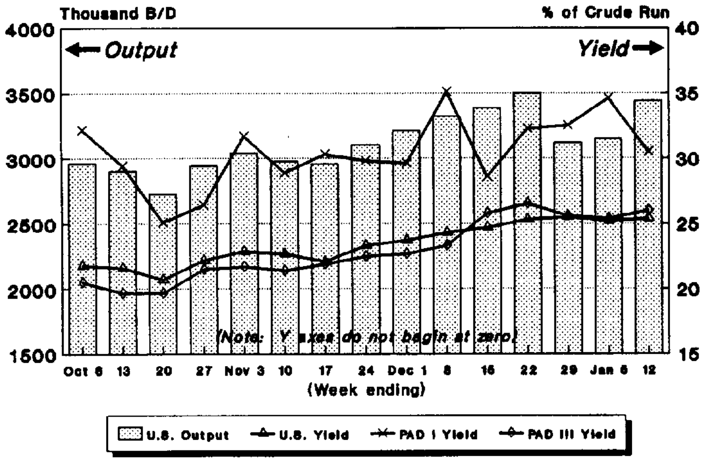
B. **Refinery Operations**

With refinery crude oil runs over 13 million B/D, each percentage shift in the distillate fuel oil yield resulted in 130-135 thousand B/D change in output. Distillate fuel yields generally swing from a low of 19-20% in the summer months to a high of 22-23% in the heating season. Even from the high end of the range, yields can technically be increased for short periods. Thus, the market routinely counts on incremental supply from U.S. refining operations during the periodic cold snaps that make up the regular winter season; for instance, a one-percentage point increase in the yield for one week would make up the demand surge for one week of 10% colder than normal weather in December.

Figure III shows weekly refinery operations data and distillate yields for October to January as reported by the American Petroleum Institute's *Weekly Statistical Bulletin.*

Figure III

Distillate Output and Yields
October 1989 - January 1990



Source: American Petroleum Institute

Refinery operations responded to the cold weather with rapidly increased distillate yields and output. From less than 3 million B/D in early November, refiners brought distillate output to 3.5 million B/D by mid-December. Yields rose 4 percentage points. On the East Coast, refiners took the yield to 35% for brief periods. The Philadelphia area, like other areas of the Northeast, was experiencing transportation logjams in December both because of the weather conditions and the soaring demand. Thus, even if product could be produced, it was not guaranteed that a barge would be available or able to move it. Hence these extraordinary yield levels were not maintained at all times.

By the time the cold hit the South, just at Christmas time, Gulf Coast refineries were producing distillate at close to historical maximum levels. Stocks were being drawn as fast as possible. Waterborne transportation in the Northeast was stretched to the limit: deliveries slipped their schedules, new supplies needed ten days to work themselves into the schedule. Stocks in New England had fallen by 50% since early November. At 3.9 million barrels, they were at a record low for so early in a heating season.

The arctic Christmas weather wreaked havoc in the Gulf Coast refining areas. As the graph shows, distillate output was forced down because refineries could not fully operate--pipes burst, pumps, valves and gauges froze. Over Christmas week crude oil runs in PADD 3 (the Gulf Coast) were forced down 1.5 million B/D. Among the companies affected were Chevron, Cities, Hill, Koch, Marathon, Mobil, Phillips, Shell and Sun. In the same period, an explosion and fire at Exxon's 455,000 B/D facility in Baton Rouge, LA, removed about 100,000 B/D from distillate output. The combination of these factors made a price explosion in the second half of December virtually inevitable in a competitive market where marketers at all levels were scrambling to meet their customer's essential needs while their suppliers had to cope with unforeseen transportation problems and technical supply disruptions.

c. Imports

As the heating season approached, import availability was one supply component which was a source of concern. In October Hurricane Hugo had severely damaged storage facilities at the Hess refinery in St. Croix, V.I., second largest import supplier of distillate to the East Coast (after Venezuela). However, by November the volume had been restored to its normal share of the East Coast market, and between November and December its volumes nearly doubled.

European imports, however, were less available as the temperature fell, because cold weather in Europe had kept exports to the U.S. East Coast down. In December 1988, distillate imports from Europe to the East Coast were 41 thousand B/D (including the USSR and Rumania). In December 1989, they virtually dried up.

In December 1988, the East Coast was able to draw supplies from 14 import sources. In sharp contrast, December 1989 only shows 4 import sources of distillate, the top three routine suppliers, Canada, Venezuela and the Virgin Islands, plus Mexico, a minor supplier. These areas of course are all geographically best suited to supply U.S. markets. The truncated foreign supply is a clear indication that Soviet, Eastern Europe, African, Middle Eastern and European supply was being used abroad. Hence, December 1989 imports to the East Coast totaled 312 thousand B/D -- 85 thousand B/D, or 20%, lower than December 1988 volumes.

IV. WHAT HAPPENED TO DEMAND?

The real story in December was *energy* demand:

- Weather-sensitive demand soared for all heating fuels--distillate, residual fuel oil, propane and natural gas, both directly, and, through surging electric demand, indirectly;

- As natural gas was sucked into residential burners, it had to be replaced in other uses. Interruptible gas users such as industrial facilities, cogenerating plants and electric utilities had to scramble for alternatives, turning to distillate, residual fuel oil and propane.

a. Electricity

According to the Department of Energy's Energy Information Administration, U.S. electricity generation in December 1989 was 11% higher than December 1988. (From January through November the 1989 electricity generation had been 2% above 1988 on average.) As the table below shows, the increases were concentrated in the South, but covered the area east of the Rockies. In some weeks, the hardest hit regions were sustaining generation increases of 20-30% from year ago levels. Rolling blackouts were necessary for load management in Florida and Texas; New England had voltage reductions. New winter peaks were set in widespread National Electric Reliability Council regions (Pennsylvania-New Jersey-Maryland Interconnection and Electric Reliability Council of Texas, for instance) and utilities across the country: Commonwealth Edison, Duke Power, and Southern Company to name some of the larger utilities. Setting new *all-time* peaks were Florida Power, Florida Power & Light, Niagara Mohawk, Tampa Electric, TVA, and Virginia Power, among others.

Table I

Electricity Generation by Region, December
(GWH)

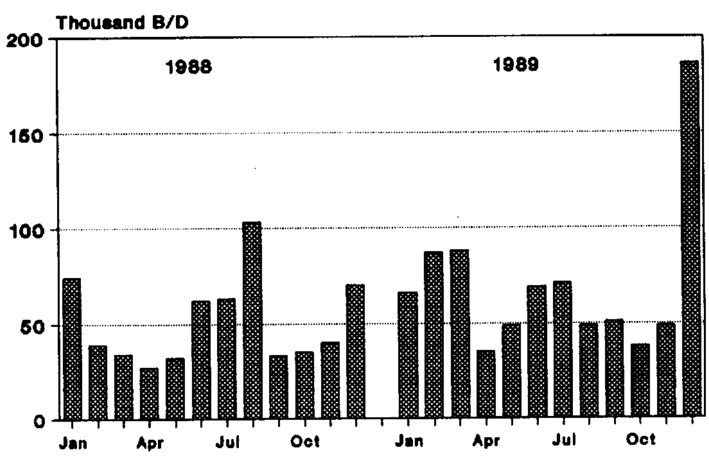
	1988	1989	%Ch
New England	8965	9952	11
Mid-Atlantic	28571	32826	15
E.N. Central	40712	44517	9
W.N. Central	18228	20189	11
S. Atlantic	44400	52104	17
E.S. Central	20097	23703	18
W.S. Central	26923	30888	15
Mountain	20991	20920	-
Pacific Contiguous	22781	22545	-1
Pacific Non Contiguous	1085	1078	-1
U.S.	232752	258722	11

Source: U.S. Department of Energy, Energy Information Administration.

The difference for oil demand in December 1989 was the need for incremental electric generation. Because gas heating demand surged, it was not available for the increase. Gas moves out of the power generation market and into the heating market each season and gas consumption for electric generation was in fact higher in December 1989 than in December 1988. According to EIA's *Electric Power Monthly*, gas consumption for electricity generation was almost 25% higher in December 1989 December 1988 (some of the increase reflects a price-induced fuel switching from gas to fuel oil in December 1988). Heavy oil consumption also increased, but only by 11%; conversely to gas, its December 1988 base was higher because of the aforementioned fuel-switching. Light oil consumption, however, as shown in Figure IV, soared to 186 thousand B/D, from 70 thousand a year earlier, a 165% increase.

Figure IV

Light Oil Consumption for Electricity Generation



Source: EIA, *Electric Power Monthly*

A strong indication that oil was substituting for gas in electric power generation was the regional distribution of the oil increase. EIA does not publish light versus heavy oil consumption data by region. But because the increase in residual fuel oil consumption for electric generation was relatively lower, changes in total oil consumption give an indication of how the 116 thousand B/D light oil increase was distributed across regions. The biggest percentage increases, by far, were in regions that are not traditionally oil dependent for electric generation. The West North Central, the East South Central, and the West South Central regions, using 13 thousand B/D in December 1988, suddenly needed 78 thousand B/D in December 1989. This increase had to fall largely on distillate supplied from the Gulf Coast which could otherwise have come to the East Coast.

b. Residential Demand

Consumption of fuels used for heating of course leaped in inverse relationship to the plummeting thermometer. Natural gas consumption in the residential sector rose 24% December-on-December. Propane, like distillate fuel oil, had to feed both residential heaters and the peaking needs of utilities; its total consumption rose 28%.

We estimate that distillate fuel oil consumption for space heating rose by 350 thousand B/D during December's cold weather. According to an annual survey by *Fuel Oil and Oil Heat*, a trade publication, residential consumers in the Northeast use on the average about 900-1000 gallons of distillate fuel per season, which works out to about 150-160 gallons for each thousand degree days. With December's cold adding about 300 degree days to normal weather, then, the distillate consumption increment per household, multiplied by the number of households using distillate, confirms the volumes suggested by broad supply/demand data.

c. Industrial Demand

The increase in industrial use of distillate is more difficult to quantify. The generally available data series of the EIA do not break down industrial sector information. In the absence of reliable data on distillate use, we must turn to anecdotal information. According to preliminary estimates, gas use in the industrial sector rose on the order of 10 percent. The sharp curtailments in interruptible volumes, however, were important for distillate demand. The impact was particularly strong in the South Atlantic (Maryland to Florida). Utility information suggests that their customers' replacements for the curtailed gas volumes represented the equivalent of up to 50 thousand B/D.

d. Demand Summary and Reconciliation

According to PIRINC's estimates, then, December's distillate consumption was at least 500 thousand B/D above its expected levels because of the abnormally cold weather: 350 thousand in the residential/commercial sector, 116 thousand for electric power generation, and perhaps 50 thousand B/D in the industrial sector.

This estimate in broadly in line with Energy Information Administration calculations: according to the EIA, petroleum consumption rises 0.11 percent for each 1.0 percent increase in heating degree days above normal.* Based on this calculation the degree-day increase (above normal) in December 1989 would have led to a consumption increase of more than 500 thousand B/D. EIA's sensitivity factor reflects very recent analysis to update its earlier (lower) estimate of degree day affect on petroleum consumption.

How was the increment supplied? According to the EIA's monthly data, 3.9 million B/D of distillate in December 1989 was supplied out of the primary system, a 350 thousand B/D increase from December 1988. What about the additional 150 thousand B/D we estimate was consumed?

▪ *Some of it came out of secondary and consumer stocks.* Primary system supplies include refinery output, imports and stock changes in "primary" inventory locations--refineries, pipelines, water-accessible terminals, and other large terminals. By definition, it excludes stocks held by any consumers, even bulk purchasers such as utilities. The EIA's *Electric Power Monthly* shows that utilities drew their own light fuel oil stocks down by 47 thousand B/D, compared to an 8 thousand B/D draw in December 1988. Thus, while utilities increased their consumption by 116 thousand B/D between December 1988 and December 1989, their purchases rose by only 76 thousand B/D. DOE's primary supply data record the smaller figure.

▪ *Some of the BTU's demanded were consumed as jet fuel.* In December 1989, kerosene jet fuel supplied on the East Coast soared by more than 100 thousand B/D over year-ago levels, after showing no increase for the first 11 months. Nationwide, the kero jet increase was 231 thousand B/D in December 1989, once again, after little growth in the first 11 months. Clearly this increase was not caused by the sudden flight of holiday vacationers. Rather, it was the emergency use of kero jet fuel for power generation by turbine and for enhancing distillate supplies via blending. Some would have been counted as "light oil" utility consumption. EIA does not generally publish end-use data on kero jet fuel moving into the industrial sector or used for blending, however.

▪ *Diesel fuel use for transportation may have dropped in December.* Diesel prices rose 25 - 30 cents/gallon in the regions most affected by the cold weather, according to the trade publication, *Lundberg Letter*. While the spike was evident in the second half of the month, hence muting its impact on December's volume, it cannot be assumed that a price increase of this magnitude would have no effect. Furthermore, stormy weather, especially of the severity encountered in the South, impedes ground transportation, further shaving volume from expected levels.

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* U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, 2nd Quarter 1990, DOE/EIA-0202(90/2Q), p. 15.

V. WHAT HAPPENED AFTER DECEMBER?

As noted previously, the January thaw this season was extreme. With more than 20% fewer degree days than normal, January 1990 was the warmest in more than fifty years. The demand surge for both oil and gas ended abruptly. Gas availability again magnified the swing in oil demand, since oil was backed out of its own temperature-sensitive load and out of the power generation spike in (normally) gas-fired capacity. As discussed in the next section, prices on volatile open markets rapidly fell back from their year-end peaks.

Distillate demand in January fell to 3.2 million B/D, a 20 percent drop from December, and a 4 percent drop from the year before. February demand, at 3.3 million B/D, was 5 percent below year-ago. Altogether, first quarter 1990 demand for distillate fuel oil was about 8 % below the EIA's *forecast* demand for the period and 4% below 1st Q '89.

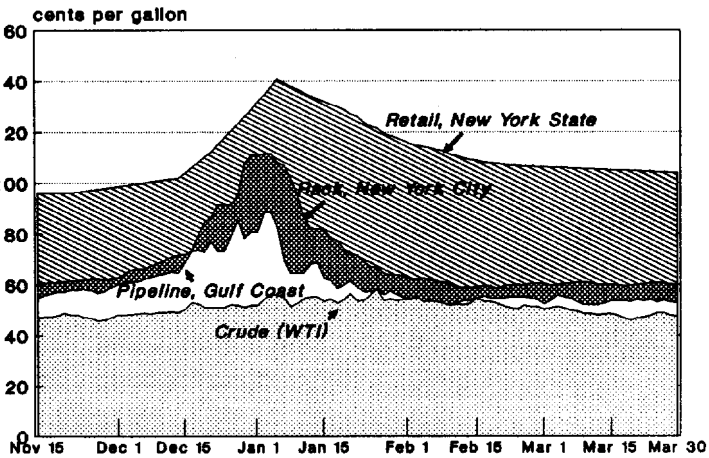
It should be pointed out that the January thaw was more than welcome. By year-end distillate stocks in the Northeast were so low that if the abnormally cold weather had lasted another 10-12 days sporadic physical shortages may have occurred. As it was, apparently no distillate customer had its fuel oil supplies delayed or curtailed during December. But in New England, for instance, distillate stocks at year-end had fallen to an historic low of 3 million barrels, about half the year-ago volume. Thus, the dramatic weather turnaround at year-end came just in the nick of time for consumers.

VI. WHAT HAPPENED TO PRICES?

In December prices soared, inventory values rose, refiner margins on distillate improved, as did margins between wholesale and refiner prices. However, margins between wholesale and retail prices eroded because wholesale prices rose faster than retail prices. In January prices fell, inventory values dropped while refiner and wholesale margins shrunk. However, retail margins recovered and stayed relatively strong throughout the remainder of the prime heating season.

Figure V

Heating Oil Prices
November 1989 - March 1990



This outline of price movements is illustrated in Figure V. The prices began to increase after several weeks of cold weather. Wholesale prices, measured as New York metropolitan area terminal prices, went from about 61 cents/gallon in mid-November to more than $1.10 in early January (*Platt's Oilgram Price Report* "low" quote). A week later, by January 10, these prices had fallen 25 cents, thus giving back half of the increase in one week. Prices on Gulf Coast spot markets rose more slowly than terminal prices in New York Harbor, and fell more rapidly: they rose by about 30 cents, and in that same week in early January gave back three-quarters of their increase. By early February, these prices were back to November levels.

a. Retail Prices

Retail prices, while rising at historic rates and gathering widespread press attention, in fact lagged the increases seen at both the refiner and wholesaler level in December . By the time those prices were peaking, the *gross* retail margin in New York had eroded to almost half its November level. During this same period, retailers were incurring extraordinary costs to meet their customer commitments. Overtime rates for delivery truck drivers are one example of increased unit costs which reduced net margins even further. Thus, during the crisis month of December heating oil dealers actually saw their gross and net profits squeezed despite soaring retail prices. This applied particularly to the majority of the dealers who hold little or no inventory of their own but operate by filling their trucks and then distribute the load to their customers.

The retail price decline, as noted, was slower than that of the more volatile spot and wholesale prices. By the end of March, New York State retail prices were 37 cents off their January peak, and 8 cents--about 8 percent--above their mid-November starting point. The end-season price this year was 10 cents above last year's, an increase not based on increased product cost since terminal prices were at about the same at the end of March in each year. Thus, the retailer's gross margin was higher at the end of the 1989/90 season than at the beginning and higher than last season. There are offsets, of course. Retailers pay expenses such as personnel costs which rise about in line with inflation, regardless of oil markets, and also have been badly hit in recent years by increased insurance costs, as all oil distributors have. It should also be kept in mind that retailers, unlike wholesalers and refiners, are not just purveyors of a commodity but provide an individual service of door-to-door delivery to their customers. Hence, at any given moment their price is only partly determined by the cost of the fuel they distribute.

b. A Note on Inventory Profits

What of inventory profits? Everyone with inventories in hand makes money when prices rise and loses money when prices fall. The oil industry, however, just like everyone else, has adopted a much leaner inventory stance in recent years. With fewer days' cover in tank, inventory profits are of necessity more limited; inventories must be replenished more often, and thus price run-ups have a shorter time to develop between shipments. In December, the industry was operating hand-to-mouth, so inventory profits were not a big issue. Another change for the industry's treatment of inventory has been the introduction of the futures contract for No. 2 oil. At least some market participants hedge their inventories with futures transactions, reducing their risk of loss, but limiting their participation in favorable price moves as well. Hedged volumes do not make inventory profits.

c. Consumer Costs

December's price spike was onerous for consumers, and particularly difficult for those on fixed or low incomes. A 200-gallon delivery on January 3, 1990, for instance, may have cost almost $100 more than the same volume a year earlier, or even just a month earlier. Overall, a typical consumer in the Northeast paid 10-15% ($100-150) more in the 1989-90 heating season than in the 1988-89 season. The range is of course created by differences in prices and delivery schedules across the region. This estimate accounts for the faster consumption during December and the slower consumption in January, February and March of this season.

It is important to note that a consumer with a large tank (or tanks) would have been particularly benefited this season, since a delivery at the price peak might have been avoided.

According to industry estimates, between one-quarter and one-third of heating oil customers pay under a budget or "even-payment" plan, a fixed payment each month, with a final adjustment in the off-season, often June. For most of these customers, the higher prices have not yet been felt. This season, unlike most, will end with consumers owing their suppliers money. (Some dealers and customers increased the monthly payment at mid-season to avoid this imbalance at the end of the budget year.) Budget plans provide an important source of financing for dealers in the early season, which they pay back, in essence, as the season progresses. The December prices exhausted the account surpluses built up to that time, leaving some operators cash-short in the peak season.

In addition to budget plans, which have been part of the heating oil business for many years, wholesalers and retailers have also become more innovative in designing fixed price or "price insurance" mechanisms. While some may have been offered prior to the 1989-90 season, many new plans have been offered recently, since the customer's distaste for the December price spike has made him or her ready to explore new ways to protect against a recurrence. For the supplier, of course, the fixed price plans offer a tool to increase market share. While the plans vary substantially in design, most involve hedging expected volumes with futures and/or options transactions.