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You may be interested.

PIRINC has prepared the enclosed report, *Energy Policy: A Few Steps Forward*.

After four years of frustration, Congress has passed, and the President signed an energy bill. The legislation comes during a period of sharp run-ups in energy prices and after clear demonstrations in recent years of supply vulnerabilities, including not just oil but also the widespread electricity blackout in the summer of 2003 and the earlier California crisis of late 2000-early 2001. The legislation contains some clear advances in energy policy for the country, including: the streamlining of regulatory procedures for LNG terminals, promoting improvement in electricity supply reliability, and adding some flexibility to gasoline supply logistics. The legislation also authorizes a substantial increase in the Strategic Petroleum Reserve. There are other provisions calling for subsidies, tax incentives, and higher standards to promote efficiency, clean coal, nuclear, renewable power, ethanol, etc., but in general, the legislation does not materially alter current energy demand or domestic supply trends, especially for oil.

There are in any case no "magic bullets." Any realistic set of policy options will still leave the country with growing import dependence and a need to manage vulnerability to supply disruptions. But there are policy options beyond those in the current legislation that can make a significant impact on the long term US energy future. It should be kept in mind that current high prices for energy are not the result of a new supply interruption but of higher demand, driven by strong economic activity that has put pressure on existing supply capability and infrastructure. These same high prices create incentives for corrective action, rewarding efforts to expand supply, shift to more efficient uses, and to develop alternatives. At the very least, energy policy should remove roadblocks to their influence. To some degree, the legislation does so. But there is a long way to go.

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Energy Policy: A Few Steps Forward

Summary

After four years of frustration, the two houses of Congress have agreed, and the President signed an energy policy bill. The Energy Policy Act of 2005 is the first piece of explicit energy policy legislation since 1992, the year following the first Gulf War. The legislation comes during a period of sharp run-ups in energy prices and after clear demonstrations in recent years of supply vulnerabilities, including not just oil but also the widespread electricity blackout in the summer of 2003 and the earlier California crisis of late 2000-early 2001. The legislation contains some clear advances in energy policy for the country, including: the streamlining of regulatory procedures for LNG terminals, promoting improvement in electricity supply reliability, and adding some flexibility to gasoline supply logistics. The legislation also authorizes a substantial increase in the Strategic Petroleum Reserve. There are other provisions calling for subsidies, tax incentives, and higher standards to promote efficiency, clean coal, nuclear, renewable power, ethanol, etc., but in general, the legislation does not substantially modify current energy demand or domestic supply trends, especially for oil.

Historically, legislating energy policy has been extremely difficult, partly because of its complexity, partly because of conflicting regional, environmental, producer and consumer objectives, and partly because of the long time-horizons involved for many policy options (such as energy taxes, opening ANWR, or CAFÉ standards) before there is a significant impact on the US supply/demand balance. A further consideration is that at the end of the day, any realistic set of policy options will still leave the country with a high degree of import dependence, particularly for oil, but to a growing extent for gas, and a need to manage vulnerability to supply disruptions.

There are in any case no "magic bullets," but as discussed in the report there are policy options beyond those agreed upon in the current legislation that together can make a significant impact on the on the long term US energy future. It should be kept in mind that current high prices for energy are not the result of a new supply interruption but of higher demand, driven by strong economic activity that has put pressure on existing supply capability and infrastructure. These same high prices create incentives for corrective action, rewarding efforts to expand supply, shift to more efficient uses, and to develop alternatives. At the very least, energy policy should remove roadblocks to their influence. To some degree, the legislation does so. But there is a long way to go.

Policies for Oil

This year, net oil imports will account for about 58% of total US oil supplies. In the Department of Energy's most recent long term energy outlook released at the end of 2004, the Reference Case projections call for net oil imports as a share of total supply to stay at about the current level through 2010 but then rise to about 65% by 2020 and 68% by 2025. In volume terms, net imports rise from about 12 MMB/D to about 17 by 2020 and 19 by 2025. These projections are not set in stone, but they do suggest that under any realistic set of policies the US will continue to meet over half of its oil requirements through imports.[1] Import dependence per se is not per se undesirable. Even at current extreme prices, availability of imports holds costs to consumers far below what they would be if the US tried to rely primarily on its own resources to meet its needs.

Import dependence should not be confused with vulnerability to disruption in world oil supplies. Some degree of dependence is inevitable and unavoidable, however vulnerability to supply disruption need not be. As long as the US participates in the world oil market, a supply disruption anywhere will impact us through its effects on worldwide oil prices.

The SPR

In these circumstances there are two policy objectives that are relevant, encouraging diversity of supply to spread risks, and the second is to have available a large inventory of prompt replacement oil to manage temporary disruptions that history tells us are virtually certain to occur. Regarding the second objective, significant progress has been made in recent years in increasing the size of the Strategic Petroleum Reserve. Since the beginning of 2001, the SPR has risen from about 540 million barrels to its authorized level under current law of 700. The just passed legislation incorporates the broad consensus within Congress and the Administration to go further and raises the authorized level to 1 billion barrels. However while the legislation authorizes the higher level it does not provide funding for doing so. Additional legislation appropriating funds is required to implement the authorization.

There are in any case significant issues about just when to fill it and when to use it. Right now, when oil prices are at extreme levels and world spare capacity is limited, adding to world demand, even marginally, to build the SPR looks highly questionable. The legislation gives some recognition to this concern.[2] There is an international aspect to the timing of any fill. Other countries with rapidly rising oil import requirements, especially China and India, are also concerned about supply security and interested in building their own strategic stocks from what are much lower starting points than the U.S. There is good reason to try to coordinate these efforts as a means of limiting their impact on already strained markets. Currently, there is cooperation on certain aspects of strategic stocks among member countries, of the International Energy Agency. But these are mainly the industrialized countries while most of the growth in oil imports, apart from the US, is elsewhere.

While the SPR is set to grow, the question of just when and how to use it needs to be revisited in light of recent history. The SPR was not used when there was a sharp curtailment of supply from Venezuela at the end of 2003, despite the looming prospect of war in Iraq, but was used to a

[1] The Department of Energy's **Annual Energy Outlook 2005,** was released in December 2004. Its Reference Case projected oil prices at about $30/barrel (2003 dollars) by 2025, well below current levels. But even their highest oil price case with $48 (2003 dollars) oil in 2025, net oil imports for that year were about 15 MMB/D or nearly 65% of demand.

[2] Section 301 calls for the Secretary of Energy to fill the SPR "as expeditiously as practicable without incurring excessive cost or appreciably affecting the price of petroleum products to consumers---."

limited extent in response to smaller, but more immediate, hurricane-related losses of Gulf of Mexico production last year. While the SPR should never be used lightly, reserving its use only for major world supply crises as occurred in 1973-74, 1979-8 and 1990 may be too limiting. In a world of limited spare capacity and a secular downtrend in commercial stocks, even modest supply losses can have dramatic effects on the world oil market. In such circumstances, a somewhat more "activist" policy may be called for.[3]

Domestic Oil Production

The latest energy legislation contains incentives in the form of royalty relief for certain types of oil and natural gas production, in particular production from "marginal properties" (defined as properties with wells with average production below 15 B/D or 90 MMBtu/D of gas), production from waters greater than 400 meters in depth, production using CO_2 injection, and specifically for gas, production from deep wells in shallow waters and from gas hydrates. With oil and natural gas prices at extreme levels, it's hard to argue that further incentives are needed. However, the royalty relief provisions are designed, explicitly in the case of marginal properties and potentially in the other instances, to share low-price risks rather than to add further to current market incentives. In the case of marginal properties, relief applies only if the price of WTI is less than $15/barrel, or if the gas price at Henry Hub averages less than $2/MMCF for 90 consecutive trading days, far below current prices.[4] In effect, the provisions would help mitigate production losses from sources that have proven most vulnerable in the past to depressed prices while costing nothing in strong markets. The other royalty relief provisions have production volume limits from any lease (except for deep gas), thereby capping the total relief available and also state that the Secretary of the Interior may place limitations on royalty relief "based on market price." The use of the word "may" leaves what will in fact happen uncertain but the case for some price-related limitations is strong in light of current price levels.

In assessing whether these steps were appropriate, or whether alternatives should have been considered, it is important to consider what influence in any case policy could have on domestic production. The answer for oil would appear to be little if any. US oil production has been declining since the early 1970s. In 2004, US crude production averaged about 5.4 MMB/D, down by about 3.8 MMB/D or 40% from its level in 1973, the year of the oil embargo and the first drastic increase in oil prices. The latest Reference Case projection of the Department of Energy's Annual Energy Outlook calls for approximately a 1% per year decline in crude production between 2003 and 2025 with the period divided between a slight increase to 2009 followed by renewed declines. Given this history and the projections for the world's most intensively explored country, the chances of a achieving a drastic cut in imports through a turnaround in oil production appear close to nil under any conceivable set of policies. But supply-oriented policy is nonetheless important. Indeed, the US oil production decline since the early 1970's would have been much worse without the implementation of two critical policies,

[3] For a detailed discussion of issues regarding use of the SPR, see the PIRINC report, **Using the SPR: Issues and Lessons from Recent History.** December 2004

[4] The threshold prices are to be adjusted for inflation as measured by the Consumer Price Index.

one regarding the Alaska pipeline, and the second, the opening of broad areas of the deepwater Gulf of Mexico to exploration and development.

In the case of Alaska, an act of Congress in October 1973, at the time of the Arab oil embargo and quadrupling of the price of oil, broke the legal logjam that prevented the building of the pipeline to bring oil from the giant, Prudhoe Bay discovery to market.[5] Regarding the deepwater Gulf of Mexico, with the prominent exception of the waters off Florida, the areas involved were bordered by states with a long history of oil and gas exploration and development. In 1983, a change in Outer Continental Shelf (OCS) leasing policy to what was called area-wide leasing allowed bids on all Central and Western (but not Eastern) Gulf of Mexico waters. In November 1995, Congress passed and the President approved, the OCS Deepwater Royalty Relief Act that provided a sliding scale of incentives for oil produced from water depths in excess of 200 meters.[6] These policy measures, along with key technological advances in exploration and production technology, have led to development of a new, prolific source of oil for the country. Currently, production from the deepwater gulf and Alaska's North Slope are contributing about 2 MMB/D or more than one-third of total US crude production. . However, there are limits to the contributions, actual and potential, from the two areas as they now stand.

Production from the North Slope has been in decline since the late 1980s despite achievements to date in sustaining production. The initial Prudhoe Bay discovery in 1968 was estimated to contain 9.6 billion barrels of oil. As of 2003, the field has produced nearly 11 billion. Twenty-seven years after the start-up of production, it is still producing at the rate of about 400 MB/D, substantial although well down from its peak of 1.6 MMB/D. The existence of the pipeline, and developing spare capacity, has allowed the development of other smaller North Slope fields that have helped limit the overall decline in North Slope production. This process is still continuing, with about 160 MB/D of production in 2003 coming from fields first brought into production in 2000 and 2001.

Policy decisions are still critical for future Alaskan production. In one promising area, the National Petroleum Reserve-Alaska, (NPRA), policy in recent years has moved in favor of expanded leasing, although subject to legal challenges[7] Indeed, the Department of Energy

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[5]Despite the embargo and price shocks at the time, the legislation passed the Senate only by one, tie-breaking vote cast by the Vice President. The close vote on the bill reflected the deep, nearly unbridgeable, conflict between those opposing development in an environmentally sensitive, pristine area and those pointing to the clear national interest in increasing oil supplies, a conflict that persists to this day.

[6] The act provided for a suspension of royalty payments on the first 17.5 MMB of oil produced from water depths of 200 to 400 meters, the first 52.5 MMB produced from depths of 400 to 800 meters, and the first 87.5 MMB from depths over 800 meters.

[7] This area has been considered a significant oil prospect for decades, having been designated as Naval Petroleum Reserve No. 4 during the Harding Administration. Four lease sales were held in the 1980s but with no oil discoveries announced. The significant Alpine oil field discovery (429 million barrels) near the NPRA triggered new interest and a new Federal lease sale was held in 1999. In 2001 it was announced that 5 of the wells drilled during the 2000 and 2001 drilling seasons had encountered oil and gas. Early last year, the Bush Administration announced a plan that would open about one-third of the NPRA to leasing and revising rules limiting activity in the northeastern area. The plan has been challenged in the courts although opposition from environmental groups appears far less intense than in the case of ANWR.

already includes expanded production from this source in its long-term energy outlook. The new legislation calls on the Secretary of the Interior to "conduct an expeditious program of competitive leasing of oil and gas in the Reserve in accordance with this Act," and provides for royalty and rental relief where it is judged necessary to do so to promote development. However, the most promising prospect for new North Slope production is the northern coastal area of ANWR referred to as Section 1002 where the most recent USGS mean value estimate of recoverable reserves on the Federal part is nearly 8 billion barrels .[8] This estimate is in fact slightly below the mean value estimate for the Federal part of the NPRA of about 9 billion barrels but the ANWR reserves are concentrated in a much smaller area, 1.5 million acres versus 22.5, and are expected to be concentrated in fewer, larger, accumulations than in the NPRA. Including Federal and Native lands as well as State offshore areas expands NPRA mean value reserves to 10.6 billion barrels on 24.2 million acres and ANWR Section 1002 reserves to 10.4 on 1.9 million acres. As a result of greater concentration of reserves, economic recoverability of ANWR reserves would be far less dependent on high oil prices and, presumably, the environmental footprint involved in bringing the oil to market would be much smaller.[9] The timing of ANWR production would also coincide with declining production from the older North Slope fields, helping maintain the use of the existing pipeline. Under current law, no leasing within ANWR can be undertaken without authorization by Congress. As was the case in the last session of Congress, the original House version of the energy bill authorized leasing within ANWR but the Senate version, under threat of filibuster, did not and the provision was dropped in conference. However, authorization was included in the (filibuster-proof) Senate Budget Resolution passed in March, surviving an attempted amendment to delete the authorization by a narrow, two-vote margin and thus might still win Congressional approval

Impact of Energy Policy Act (House Version) On Energy Production in 2025

	Reference Case	House Bill	Difference
Total Energy Production			
QBtu	**82.64**	**84.87**	**2.23**
MMB/D O.E.	**37.74**	**38.75**	**1.02**
Domestic Crude Production, MMB/D	**4.75**	**5.76**	**1.01**
of which opening ANWR	**0.0**	**0.94**	**0.94**

% Increase in Total Energy Production from ANWR = 92%

In an analysis of the House version of the bill released in July, the Department of Energy found that opening ANWR

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[8] The designation refers to Section 1002 of the 1980 Alaska National Interest Lands Conservation Act (ANILCA). This part of ANWR was to be the subject of studies including the environmental impact of oil and gas exploration and an assessment of hydrocarbon potential. For a detailed discussion of issues regarding ANWR see the PIRINC report, **Energy Supply Prospects and Politics: Focus on Alaska**, April 2003 In 1995, Congress included such authorization within the "Seven-Year Balanced Budget Reconciliation Act of 1995" (H.R.2491). In December of that year President Clinton vetoed the bill, citing the authorization provision among the reasons for his action.

[9] The USGS estimates, based on mean values for technically recoverable oil, that at $25/barrel delivered to the West Coast market (netback values to the wellhead would be significantly lower) economically recoverable reserves from ANWR Federal areas would be 5.6 billion barrels versus 3.7 for the NPRA.

would have by far the largest impact on long term US energy supply. .[10] Results of their analysis for 2025 are summarized in the table above. Collectively, the provisions of the House bill raise Reference Case total energy production in 2025 by 2.2 QBtu, or the oil equivalent of 1 MMB/D. The opening of ANWR accounts for 0.94 MMB/D or about 92% of the increase in total energy production.[11] Eliminating ANWR effectively removed nearly all the potential energy from the final legislation.

In the deep water Gulf of Mexico oil production is still rising but the fields tend to have very high production flows---and relatively high depletion rates. Moreover, most of the deepwater areas of the Central and Western sections have already been leased. Only the Eastern section remains as a potential new frontier area, although subject to similar intense opposition that characterizes the ANWR debate.

The new legislation takes some steps to promote more informed discussion of these issues in the future. It calls for a "Comprehensive inventory of OCS oil and natural gas resources" with the first report on the inventory, including an analysis of "restrictions or impediments" to development within six months of enactment. The legislation also calls for the establishment of a North Slope Science Initiative to provide a better understanding of the area's eco-systems and the impact of past and prospective development activities. Future debates should have a better framework of scientific information, although whether decisions become easier remains to be seen.

Containing Demand

Over the past 10 years, net oil imports have risen by about 4.2 MMB/D or 53%, with 1.7 MMB/D of the increase coming since 2000. These increases are much larger than the declines in domestic oil supplies for the same timeframes, about 0.6 MMB/D and 0.25 respectively with the differences reflecting the more substantial impact of higher demand on US import growth. Among the major products, gasoline stands out, with current demand nearly 1.5 MMB/D, or nearly 20%, above its 1995 level with about half the increase coming since 2000. The components of gasoline demand growth are well-known, approximate stagnation at about 21 MPG for the US light duty vehicle fleet, aided by a rising market share for light trucks, continued growth in vehicle ownership, and growth in miles driven per vehicle. The strong income gains of recent years have encouraged these trends, although the extremely high fuel prices seen this year are provoking changes.

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[10] **Impacts of Modeled Provisions of H.R. 6 EH: The Energy Policy Act of 2005**, released by the Energy Information Administration, July 2005.

[11] The analysis projected an increase in 2025 ethanol use versus the Reference case of about 1.8 billion gallons, equivalent to about 70 MB/D of gasoline. The final bill contains a much higher ethanol requirement, 7.5 billion gallons by 2012 versus the House requirement of 5 billion gallons. On the other hand, the Reference Case price for oil in 2010 was only $25/barrel ($2003) and about $30 in 2025. Higher oil prices would push up ethanol use in any case. The analysis notes that if prices in 2005-2012 were about $7 above Reference Case levels, ethanol use would rise to the House requirement of 5 billion gallons without any change in the law. Current and futures market prices exceed Reference Case levels by far more than $7, adding still further market encouragement to ethanol production.

While bills have been introduced from time to time to raise CAFÉ standards, there are no direct provisions to do so in the latest legislation. Nor were there any in the energy policy legislation considered by the previous session of Congress. The CAFÉ standard for new passenger cars reached 27.5 in 1985, where it has more-or-less remained ever since. The CAFÉ standard for light trucks 20.7 MPG in 1996, where it remained through model year 2004. The standard has been raised to 21 for the 2005 model year and 21.6 for the 2006 model year.[12]

CAFÉ standards have certain demonstrated limitations. They set only a floor to fuel efficiency with no real incentives to do better. Changes in CAFÉ standards impact overall gasoline demand only as the new vehicles subject to stricter standards are absorbed into the fleet. This is a long process. On average, new vehicle sales amount to about 7.5% of the existing fleet. Moreover, today's vehicles stay on the road a long time. The median age (where half the fleet is older and half younger) of cars is about 9 years, and for light trucks, about 8 years.

Moreover, CAFÉ regulations as currently structured have had perverse effects, especially provisions regarding alternative fuel vehicles,. The Alternative Motor Fuels Act of 1988 provided an incentive for vehicles capable of using alternative fuels (as apart from the actual use of alternative fuels) that allowed a vehicle a bonus in the MPG used in calculating overall CAFÉ compliance.[13] As of 2003, there were about 5.5 million alternate fuel light duty vehicles on the road, of which about 90% were gasoline vehicles with ethanol capability---and most of them were SUVs. Only minimal amounts of the ethanol fuel (E85, a blend of 85% ethanol and 15% gasoline) were used. In 1993, the effective increase in CAFÉ MPG for compliance purposes from this provision was limited to 1.2 MPG. The incentive program has been extended by regulatory action to 2008, although with a slight reduction in the limit to 0.9 MPG.[14]

There is clearly room for adjustments in the CAFÉ program to eliminate distortions and create incentives for doing better than the minimum. There is also good reason to continue the process of narrowing differences in treatment between light trucks and cars. There is a case for raising the CAFÉ standards themselves, although doing so aggravates the problems and costs inherent in such an approach. The current program forces domestic manufacturers to produce and cross subsidize smaller vehicles to meet overall fleet average requirements even when their competitive production advantages lie elsewhere. An alternative, setting MPG improvement requirements by weight class would seem to be a way around this problem but creates others, in particular, incentives at the margin to shift vehicles into the heavier classes.

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[12] In 1996, Congress through its appropriation power prohibited the NHTSA, the responsible agency from imposing increases in the light truck standard. The freeze was lifted in 2001. In 2003 the NHTSA through administrative action raised the standards for model years 2005 and 2006.

[13] For example, a vehicle dedicated to an alternate fuel such as natural gas, ethanol, methanol, or LPG, that achieved on a gasoline-equivalent basis an average 15 MPG, could for CAFÉ purposes, divide that figure by 0.15 and include it as if it were 100 MPG vehicle in calculating its CAFÉ fleet average. If the vehicle could use gasoline or an alternative, the law allowed for an averaging of the gasoline and alternate fuel MPGs. If both were rated at 15 MPG, the vehicle for CAFÉ compliance purposes would be counted as a 26 MPG vehicle.

[14] The new legislation (Section 704) calls for a review of the program including the amounts of alternative fuels actually used by the alternative fuel capable vehicles and actual amounts of petroleum displaced.

The new law does include tax incentives for advanced vehicles, fuel cell, hybrid, lean burn with a linkage between the amount of the credit and the improvement in MPG versus the 2002 model year baseline city MPG for vehicles of a comparable weight class. There is also a provision for grants to encourage domestic production of efficient hybrids and advanced diesel vehicles. Regarding diesel, the Act calls on the Secretary of Energy to accelerate efforts to develop and demonstrate technologies that will enable diesel vehicles to meet the current Tier 2 emission standards for passenger vehicles and the 2007 standards coming into effect for heavy duty vehicles.[15]

While the issue of CAFÉ standards was at least debated within Congress, the economics profession's preferred, market-based, tool for dampening demand, higher gasoline taxes was not.[16] Higher taxes raise the cost of driving the current fleet of vehicles, especially the least fuel-efficient, and encourage new-car buyers to choose more fuel-efficient vehicles without any of the problems associated with CAFÉ standards. Moreover, revenues from a higher gasoline tax flow to the government and are available to recycle via reductions in other taxes, finance government spending, or reduce the deficit. For consumers, the current impact of the extremely high gasoline prices is similar to a tax, (although the distribution of the higher revenues is very different) and there have already been noticeable effects. New passenger vehicle sales data through May showed a slight gain in market share for cars as opposed to light trucks (minivans, vans, SUV's and pick-up trucks) with sales of light trucks down by about 2% versus the first 5 months of 2004. The declines were concentrated in the large SUV's, where sales were off by about 20%. These trends were reversed in June as a result of heavy discount campaigns begun by the auto manufacturers.[17]

These shifts are directionally what would be expected but they are modest compared to the changes in fuel prices that influenced them. Retail gasoline prices for the first six months of this year are up 15% versus the same period last year, and 30% versus the first six months of 2003. The differences between the extent of the price increases and the observed changes in consumer behavior to date are reminders that in the short term, price elasticity, a measure of consumer response to price changes, is very low while of course the impact on consumer pocketbooks is immediate. Enacting a schedule of future gasoline tax increases could ease this mismatch in effects. Such an approach impacts consumer (and vehicle producer) expectations and choices (but not pocketbooks) in advance of the actual tax-induced price increases, thereby reducing ultimate costs for consumers. When gas prices are at record levels, higher gasoline taxes may

[15] The diesel is a commercially proven technology that is already delivering substantial efficiency gains to the European passenger vehicle fleet. But as of now, despite substantial improvements, none of the diesel passenger vehicles on offer in the US meet the permanent Tier 2 standard, although they do qualify under transitional provisions. A "clean" diesel could be very attractive to US consumers and make a significant dent in US oil demand. For a detailed discussion of the diesel, see the PIRINC report, **The Diesel Car: A Beautiful Swan Abroad, An Ugly Duckling at Home**, released March 2005 and available at: www.pirinc.org.

[16] The Federal gasoline tax is 18.4 cents/gallon. It was last raised by just over 4 cents/gallon to its current level in October 1993 with part of the increase initially dedicated to deficit reduction.

[17] The market share of light trucks rose to nearly 58% of sales in June and the year-to-date sales decline for large SUV's was cut to 10.6%. Note that year-to-date sales of hybrids through June reached almost 93,000, about 2.5 times the 36,000 units sold in the first 6 months of 2004.

look particularly unappealing to the public. But if and when prices fall back, the issue could be reconsidered. It should also be kept in mind that the Federal gasoline tax has fallen by about 25% in inflation-adjusted terms since it was last raised in late 1993. Moreover, higher ethanol use is also reducing revenues from this tax.

Oil Logistics Concerns: The Oxygenate Requirement and Ethanol

In recent years, an already complex distribution system for gasoline has been further complicated by actions taken by California, New York and Connecticut to ban MTBE, what had been by far the most widely used oxygenate for satisfying Federal minimum 2.1% by weight oxygenate requirement for reformulated gasoline. Although the required emissions characteristics of reformulated gasoline can be met without oxygenates, the Federal requirement, and refusal to waive it, meant in practice a surge in demand from both coasts for ethanol, produced almost entirely in the Mid-West, a product with its own special logistics requirements,[18] Thanks to strong increases in fuel ethanol production, up nearly 60% between 2002 and 2004, early fears of potential shortages failed to materialize. The anticipated higher costs of the shift to ethanol have been overtaken by the escalation in oil and gas prices.

The new legislation eliminates the oxygenate requirement for reformulated gasoline, adding needed flexibility to the current supply system. Section 1502 also contains "findings" regarding MTBE, namely that the substantial investments were made by the fuel industry in MTBE production and distribution systems in response to the oxygenate requirement. The section also allows claims related to contamination due to MTBE to be moved to Federal District Court. The findings statement about MTBE investments in response to a Federal requirement relates to a key issue that helped sink the last energy bill and was once again a source of conflict between House and Senate, namely, defective product liability.

The initial House version of the new Act, (and of the failed 2004 legislation) provided a "safe harbor" from defective product claims filed after a certain date for MTBE <u>and renewable fuels</u>, provided there was no violation of an EPA control or prohibition. The House bill stated clearly that protection did not apply against other claims including negligence, or liability for environmental remediation. The rationale for this treatment was that MTBE (and even more explicitly in the future, renewable fuels) was for all practical purposes required to meet a Federal mandate, in this case, the minimum oxygenate requirement, and that Congress understood this at the time the mandate was enacted. The provision faced strong, ongoing opposition in the Senate, with opponents arguing that polluters should not be shielded from claims for damages caused by their products. The provision was not included in the Senate version of the bill and dropped in Conference.[19] The final bill also dropped provisions in the House bill providing for an eventual Federal ban on MTBE use.

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[18]Ethanol must be shipped separately and blended at the terminal rather than blended at the refinery and shipped as part of the gasoline barrel. While reformulated gasoline can be made without oxygenates, short-term supply limitations and cost factors for the alternatives would have meant a substantial role for ethanol in any case.

[19] Although there has been strong opposition within the Senate to product liability protection in the case of MTBE, opposition has been less determined for another product group, guns. On July 29, the Senate approved by a vote of

The elimination of the oxygenate mandate, effective immediately after enactment in California and 270 days later elsewhere, and the denial of product liability protection creates a problem for current producers, importers, and distributors of MTBE and gasoline blended with MTBE that could likely have negative transitional effects on supply. The elimination of the mandate removes a key defense against product liability lawsuits, namely MTBE was (and is) a legal product that was understood to be needed to meet a Federal mandate, and thereby raises legal risks of continuing to be involved in its supply chain. The result could be a more rapid decline in availability of MTBE (currently about 150 MB/D) and near-term price pressures on supply of alternatives, and on gasoline itself. Imports of gasoline blended with MTBE are also at risk. While imports in the form of unfinished gasoline could go up, there would still be a need to find the substitutes, and have in place the logistics system to deliver them for blending. In a tight market, the net loss of supply, 50-100 MB/D, during the transition period could have large, visible, if temporary, upward price effects.

It has been long understood that elimination of the oxygenate program would be accompanied by another measure to promote ethanol use, specifically a "Renewable Fuel Program" requiring increasing volumes of almost exclusively ethanol to be used in the gasoline pool. The final legislation calls for renewable fuel volume in gasoline to reach 4 billion gallons in 2006 (about 2.8% of the gasoline pool) rising to 7.5 in 2012, and to maintain its 2012 share of the gasoline pool (about 4.6% of the Department of Energy's Reference Case 2012 gasoline demand) thereafter.[20] In the first 5 months of this year, fuel ethanol production is averaging about 240 MB/D, equivalent to an annual rate of 3.7 billion gallons, not far from the 2006 required volume. Given the inevitability of a mandatory program to promote ethanol, the method chosen has much to commend it. The program allows for tradable credits as opposed to physical per gallon obligations, allowing the mandate to be fulfilled in the most logistically efficient manner. The program also provides for one-year carry-forwards of credit deficits and allows temporary program adjustments in case of supply problems. However, with a more rapid rundown than previously anticipated for MTBE, impacted terminal operators, importers and others who might have planned on buying credits to comply in the near term with the ethanol mandate will be looking for physical volume instead, adding temporarily both to demand, and to pressure on distribution capability. In effect, the near-term cost-saving benefits of the tradable credit system will be reduced as a result of the more rapid rundown in MTBE.

With the establishment of a growing, guaranteed market for ethanol in place, it becomes questionable whether the current Federal tax incentives for ethanol (equivalent to over 50

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65 to 31 a bill to prohibit lawsuits against gun makers and distributors for misuse of their products during the commission of a crime. For proponents of the measure, "This bill is intended to do one thing and that is to end the abuse that is now going on in the court system of America against law-abiding American businesses when they violate no law." From a quotation attributed to Senator Craig of Idaho in the New York Times story on this subject dated July 30, 2005.

[20] There are a number of uncertainties regarding the environmental and health implications of a substantial expansion of fuel ethanol and other MTBE substitutes in the gasoline pool. The legislation calls on the EPA to conduct a study and report within two years on the effects of increased use of ethanol and other MTBE substitutes on public health, air quality, and water resources. It also calls for a study and report on the increase in evaporative emissions of VOCs resulting from higher ethanol use.

cents/gallon of gasoline) are still needed or warranted. This issue is not addressed in the legislation. In terms of impact on the US energy balance, the updated Department of Energy Reference Case projects ethanol production in the 2010-2015 time period at about 4 billion gallons, the 7.5 billion gallon requirement for 2012 would amount to an increase of about 225 MB/D of ethanol supply. However, since the Btu content of ethanol is less than the average for gasoline, 76 thousand versus about 120 thousand Btu/gallon, the savings in oil would be significantly less.

The legislation also provides a tax incentive for new refining capacity, expensing of 50% of the cost of expanding capacity ((ex lubes and asphalt) by a minimum of 5% for capacity put in service before 2012. Although refinery margins have been favorable in recent years, there are considerations that would support some incentives. After years of global surplus, refining capacity, especially for products meeting US specifications, is tight and likely to remain so for several years, raising costs of relying on the world market to make up for domestic product supply deficits. Moreover, US refiners have to make major investments to meet new mandates for cleaner diesel and gasoline, as well as to conform to tighter national, regional and local air quality regulations.

The legislation takes some steps to ease problems associated with so-called "boutique fuels," that is to say the reduced fungiblity of gasoline resulting from the proliferation of different geographic fuel specifications. The legislation attempts to cap the number of such fuels at their number as of September 1, 2004. More important, it provides for temporary waivers of restrictions on use of a fuel or fuel additive in cases of "extreme and unusual fuel or fuel additive supply circumstances---," and provides legal protection for those acting in response to the waiver. The need to allow for such contingencies is magnified by the rapid increase in supply requirements for ethanol and other additives to replace MTBE in the gasoline pool. The potential for problems is not confined to gasoline. Beginning June of next year, refiners must make widely available (at least 80% of the total pool with segregation required for the remaining higher sulfur product) on-road diesel with a maximum sulfur content of 15 ppm, well below the current 500 ppm maximum with all diesel to conform to the new specification by 2009. It is important to have in place flexibility to deal with possible unanticipated shortfalls in supply in the early stages of compliance.

Natural Gas

Natural gas has been the clear favorite of the fossil fuels and Congress has the least difficulty on reaching agreement on policy matters. Natural gas is the least polluting of the fossil fuels and, thanks to combined cycle technology can generate clean electricity at very high efficiency rates. Unlike oil, most of the gas consumed in the U.S. is produced here while most imports come from neighboring Canada. But the gas market is changing in ways that indicate the need for greater caution in assessing the future for gas, and greater policy attention to supply concerns. The most visible indicator of change is its cost. In the second half of the last decade, Henry Hub spot gas prices averaged well below $3/MMBtu. But the first half of this decade has seen a sharp escalation, with prices reaching nearly $6 last year and averaging close to $7 ($42/oil equivalent barrel) for the first half of this year. For consuming regions far from the main domestic sources of supply, there have been occasional spot price spikes to levels far above these near-wellhead prices.

The step changes in prices are the result of supply limitations. Domestic production has been more-or-less stagnant for about 10 years, with this year's level estimated to be about 4% below its last, 2001 peak. Rising imports have helped compensate, with net imports rising from about 14% of total supply in 1995 to about 20% today. However, in recent years imports from Canada, which supplied 99% of total imports in 1995, have slowed dramatically. From 1995 to 2000, imports from Canada, grew by about 25%; but by only 2% from 2000 to 2004, although with signs of further growth this year. The impact of slowing growth in Canadian supplies has been mitigated by rapid growth in LNG imports. The global market for LNG is growing rapidly and there appears to be ample current and potential supply to meet it. The ability of a country to draw on this market depends on the amount of LNG terminaling and re-gasification capacity in place to receive it.

Since gas prices have been offering strong incentives for new supply, policy concerns have focused on what legislative and regulatory roadblocks to new supply may exist and what could reasonably be done to eliminate, or at least modify them. Last October, Congress took a major step in this direction by providing a streamlined, expedited regulatory review process for a pipeline to bring about 35 TCF of stranded Alaskan North Slope gas to market.[21] While there are still significant risks associated with a project that costs $20 billion and has a 10 year time frame, the action taken by Congress last year significantly improves the prospects of the pipeline actually being built. The latest energy policy legislation streamlines the regulatory review process for LNG terminals, which can be brought on line in a shorter time-frame, and where the economics are more robust, than is the case for the Alaska pipeline.

When all is said and done, the supply environment for gas is moving toward greater imports and a longer, more complex supply chain. As the US becomes more embedded in the world market, security issues can become more important. There are many potential suppliers of internationally traded LNG. Some are nearby, notably Trinidad and Venezuela, while Algeria is supplier of long-standing. But other potential sources for growth are much further away, including very large potential resources from the Persian Gulf. Although the global market is moving toward integration, for the foreseeable future LNG will not have the same supply flexibility as internationally traded oil. However desirable it might be to encourage expanded gas use, recent market developments, as well as the prospective changes in the physical supply

[21] The measure was included in the Fiscal Year 2005 Military Construction Appropriations Act. Also included were provisions for a loan guarantee, accelerated depreciation and a tax credit for a gas conditioning plant. Similar provisions were included in the energy policy legislation that had failed to pass a few months earlier. The 35 TCF is the latest USGS estimate of current reserves in the Central North Slope where all current oil production is taking place. The USGS estimates there is another 37 TCF of undiscovered gas in the same area. All would be accessible to the route of the proposed pipeline. The USGS also estimates the NPRA contains 73 TCF of undiscovered gas and the ANWR 1002 area another 9. See the news release, "New USGS Oil & Gas Assessment of Central North Slope, Alaska," released May 11, 2005 and available at: www.usgs.gov/newsroom/article_pf.asp?ID=705

environment, suggest caution in relying too heavily on gas to supply the country's growing energy needs.

Coal and Nuclear: The Stepchild and the Orphan

While the problems of oil and gas have garnered much of the policy spotlight, two other fuels, coal and nuclear, have tended to get far less attention, and the attention they have gotten over the years has focused on environmental, and in the case of nuclear, safety and radioactive waste disposal concerns. Yet these two fuels remain major contributors to the US energy balance and critical fuels for electricity generation. Currently, coal accounts for roughly half of US net electricity generation while nuclear accounts for about 19% with both larger than the current 17% of power generation from natural gas. Both coal and nuclear based generation have been growing, with coal-based power up nearly 20% over the past 10 years, and nuclear up 15%.[22] The gain in nuclear has come despite virtually no change in overall generating capacity, indicating strong gains in operational performance.[23]

Although coal too has experienced certain supply problems, notably production shortfalls for low sulfur eastern coal and transport problems limiting the growth of West-to-East shipments of low sulfur subbituminous coal, nonetheless, this fuel is by far the country's most abundant and lowest cost fossil fuel for the production of electricity. In the first quarter of this year, the average cost of coal delivered to power plants averaged $1.49/MMBtu, far below the $6.09 cost reported for gas. Even allowing for the higher efficiencies of gas combined cycle technology, at these cost differences, coal generated power is considerably cheaper.[24] Of course cost is not the only issue. Historically, coal burning has been associated with high levels of emissions of pollutants, in particular sulfur dioxide, and NOx Here however, there has been great progress, thanks to the combination of increasingly tight national and regional cap and trade programs and the installation of advanced emission control technologies. This year, the EPA finalized regulations establishing a national cap-and-trade program to reduce mercury emissions from coal-fired power plants. The initial round of reductions are linked to those achievable as co-benefits from current post-combustion controls for sulfur dioxide and NOx but other technologies specifically targeting mercury, in particular activated carbon, are emerging that will offer more extensive reductions.

Greenhouse gas concerns raise more difficult issues for coal. There are as yet no economic technologies for directly sequestering CO_2 from coal-based power generation, although emerging IGCC (Integrated Gas Combined Cycle) technology may offer such a prospect in the future. However, since CO_2 reduction need not be source-specific, persisting wide fuel cost differentials would allow coal-based generating units to support low-cost CO_2 reduction efforts elsewhere. Indeed, coal-based power generators are already among the more prominent participants in the

[22] Although the percent increase is far larger for gas, up about 60%, the increase in TWh was significantly larger for coal, about 295 versus about 250. The increase for nuclear is about 110.
[23] There were 99.5 GW of nuclear capacity in 1995 and 99.2 in 2004.
[24] Assuming an average generation efficiency of about 35% for a coal unit and 50% for gas combined cycle, these fuel costs/MMBtu translate into about $15/MWh for coal versus about $41 for gas

"Voluntary Reporting of Greenhouse Gases Program," administered by the Department of Energy.[25]

The new energy legislation provides tax credits for investment in "Clean Coal Facilities," distinguishing between IGCC projects, eligible for a 20% credit and others eligible for a 15% credit. The aggregate amount of credits available is capped at $1.3 billion with $800 million designated for IGCC technology. In dividing up the credits for IGCC projects, the Secretary of Energy is to do so in relatively equal amounts between users of bituminous, subbituminous and lignite coals. The Secretary is to give high priority to IGCC projects with greenhouse gas recapture capability. The remainder of the credits are for units that have a design net heat rate of 8,530 Btu/KWh, or a 40% generation efficiency, well above the 33% US average for the first four months of 2005.[26] However, the heat rate threshold is adjusted upward for coals with an energy content below 13,500 Btu/lb with an extra allowance for coal with less than 7,000 Btu/lb. The adjustments reduce the effective efficiency threshold to about 37.5% for subbituminous coal and to about 34% to 35% for lignite. There is a strong case for government support of research and development for efficient, clean coal technologies, including support of demonstration projects (also provided for in the legislation) to promote a sustainable future for our most abundant fossil fuel. But the case for tax credits is diluted the more it focuses on "picking winners" and the more it attempts to satisfy other interests as well. While the legislation tilts the credits toward a specific advanced coal technology, IGCC with carbon sequestration capability, it is not obvious, at least as of now, that this advanced technology is in fact among the lower cost options for reducing greenhouse gases, or even for sustaining coal use. Until greenhouse gases, especially CO_2, are made economically visible, the cost seriatum of possibilities, and the ranking of IGCC technology among them, will remain hidden.

Nuclear of course emits none of the above pollutants and fuel costs are far lower than for any of the fossil fuels. Concerns about nuclear lie elsewhere--- still unsettled disposal issues regarding spent fuel, and safety, with the latter concern aggravated in the aftermath of 9/11. Economics have also been unfavorable, with the combination of high capital cost, long lead-time and regulatory uncertainties deterring investment. Yet, although there is no building in the U.S., there is significant activity elsewhere. The IAEA reports that as of May of this year, 25 nuclear plants were currently under construction, mainly in Asia, while 4 new units have come on line (in India, Japan, and South Korea). Thus concerns elsewhere about supply security and costs of alternatives are keeping nuclear in the global energy picture.

[25] The program was established under Section 1605(b) of the Energy Policy Act of 1992. It provides for the reporting of activities that reduce emissions of greenhouse gases or increases carbon fixation or sequestration. In 2003, electricity providers accounted for about 2/3 of total reported greenhouse gas reductions.

[26] The units also have to meet certain emissions criteria: a 99% removal rate for sulfur dioxide and 90% for mercury as well as NOx and particulate emission limits of 0.07 pounds/MMBtu and 0.015 pounds/MMBtu respectively. The efficiency criteria shown are for new units. For existing units to qualify, the minimum efficiency threshold is 35% and an improvement in design efficiency depending on coal heat content. For coal with a 9,000 Btu/lb or higher content, the improvement threshold is 7 percentage points, for 7,000 to9,000, 6 percentage points, and for coal with heat content below 7,000 Btu/lb, 4 percentage points.

The most immediate issue for nuclear in the US is what happens to existing capacity. Nuclear units were licensed to operate for 40 years. About 10% of current U.S. capacity will reach this limit by 2010 and 40% by 2015. A license can be renewed for up to an additional 20 years of operation provided the safe operation of the unit is assured. The Nuclear Regulatory Commission estimates the licensing process from time of receipt of application to decision is about 30 months, including time for public participation in the process. To date, the Commission has received 21 applications and has issued 13 license renewals. The Commission has received 25 letters of intent to file future applications. The timely processing of current and future applications, without compromising safety considerations, is clearly in the national interest. The new legislation does not deal directly with this issue, although it does call for the establishment of a Nuclear Energy Systems Support Program "---to support research and development activities addressing reliability, availability, productivity, component aging, safety and security of existing nuclear power plants," all key elements of any life extension decision.

The escalation of fossil fuel prices already helps the economics of potential new nuclear plants and the new law provides additional help in the form of a tax credit of 1.8 cents/KWh (the same rate as the wind energy tax credit) for power produced during the first eight years of service of a unit based on a design approved by the Nuclear Regulatory Commission after December 31, 1993.[27] Even so, it's not clear the economics for new units will be decisive. A predictable regulatory environment that maintains stringent safety standards is required, as is progress in settling issues involving safe management of spent fuel. The new law offers help in coping with regulatory risks, with provisions authorizing financial support for new reactors that face procedural delays on the part of the Nuclear Regulatory Commission and/or delays due to litigation.

In any case, even if the US never builds another nuclear plant, international concerns regarding operational safety and spend fuel management (and proliferation) will remain, and even intensify. The US must continue to be engaged in efforts to resolve them as a matter of national security. Provisions of the new law that help sustain the US nuclear knowledge base support this national interest.

Electricity

The widespread electricity blackout in the Mid-West and East last summer, and the electricity supply crisis in California in late 2000-early 2001 have made reliability of supply a matter of acute public concern. The latest energy legislation provides for the certification by the Federal Energy Regulatory Commission (FERC) of an Energy Reliability Organization (ERO) with responsibility for the development and enforcement of reliability standards applicable to all the participants in the public power system. Neither the Commission nor the ERO are authorized to order the construction of generation or transmission capacity but the Act does provide a clear

[27] The aggregate amount of credits allowed is subject to a 6,000 MW national capacity limit and an annual dollar limit of $125 million. Pro-rationing is provided for should the claims for credits exceed the limits. Only units entering service before 2021 are eligible.

procedure for breaking regulatory and other legal bottlenecks holding up needed transmission infrastructure improvements.

The Secretary of Energy will be authorized, after appropriate study to designate any geographic area experiencing transmission capacity constraints or congestion as a “National Interest Electric Transmission Corridor.” The FERC is authorized to issue a permit for construction or modification of transmission facilities in such a Corridor in cases where a State agency has withheld approval for more than one year after the permit application has been filed, or one year after the designation of the area as a National Interest Corridor, whichever is later. The Act also allows the exercise of eminent domain in the appropriate US District Court to acquire rights of way subject to a requirement of just compensation.

Other provisions also encourage improvements and rationalization of the transmission system, promote market transparency, encourage time-based metering, new appliance efficiency standards, etc. In general, these were not controversial, and many were carried over from the proposed legislation considered by the previous Congress.