RECENT DEVELOPMENTS IN TEXAS, UNITED STATES, AND INTERNATIONAL ENERGY LAW

I. INTRODUCTION

This section of *Recent Developments in Texas, United States, and International Energy Law* consists of selected discussions of recent case law, legislation, and regulations that affect the oil, gas, and energy industries.[1] The first section focuses on Texas. It contains short summaries of recent Texas court decisions and an article by Texas Railroad Commissioner Victor G. Carrillo in which he discusses the high levels of oil and gas activity that Texas has experienced in recent years and the challenges that this poses for the Railroad Commission. The second section focuses on national issues. It includes summaries of several recent federal court decisions, as well as an article from Pablo A. Ormachea examining state incentives for ethanol production and giving a quantitative analysis of their effectiveness. Finally, in a section focusing on international energy law, Steve Zhang and Paul Saydak summarize the regulations that govern sales of oil and refined products in China, with a particular focus on areas of potential market liberalization.

1. The content of the Recent Developments section is provided for general information purposes only. The case summaries and short articles may serve as a useful starting point in the legal research process, but are not intended as a substitute for primary research of the laws of the jurisdictions discussed.

II. RECENT DEVELOPMENTS IN TEXAS ENERGY LAW

A. Texas Oil, Gas, and Energy Case Summaries

1. Coastal Oil & Gas Corp. v. Garza Energy Trust, No. 05-0466, 2008 WL 3991029 (Tex. Aug. 29, 2008).

Issue: Whether hydraulic fracturing stimulation (fracing) can constitute a subsurface trespass for which damages can be sought when it causes drainage from a neighboring property.

The respondents in this case, whom the court collectively referred to as Salinas, leased the mineral rights on a tract of land to Coastal Oil & Gas Corporation. Coastal also owned and operated an adjacent tract. Both tracts were located over the Vicksburg T natural gas reservoir in Hidalgo County—a "tight," imporous sandstone formation from which gas cannot be commercially produced without hydraulic fracturing stimulation.

Coastal had fraced a well on their tract that was located 660 feet from the border with the Salinas's property. Salinas alleged that Coastal's fracing operations on this well resulted in subsurface fissures that extended beyond the property line and caused drainage of natural gas—from the tract leased from Salinas to the well on the Coastal-owned tract, where Coastal extracted the gas without paying a royalty to Salinas. Salinas claimed this was a subsurface trespass and sought damages equal to the value of the royalty on the gas allegedly drained from their land.

The court held that the rule of capture precluded a claim for damages due to drainage caused by hydraulic fracturing that extends beyond lease lines. It said Salinas did not claim an injury for which damages were recoverable because, under the rule of capture, any gas drained from the Salinas property belonged to Coastal as soon as it was extracted from Coastal's well. The court refused to alter the rule of capture to make such a claim recoverable. It explained that the rule of capture already allows landowners recourse against drainage by drilling their own wells (or by compelling a lessee to do so) and noted that representatives from all sectors of the industry—including regulators and royalty owners—had filed amicus briefs opposing the extension of liability to drainage caused by fracing.

The court limited its holding to drainage-related claims and did not answer the larger question of whether fracing can ever result in a claim for subsurface trespass. Additionally, as Justice Willett noted in a concurring opinion, the court seemed to leave open the possibility of a claim if a plaintiff could show that a defendant's fracing caused injuries

other than drainage, such as damages to a plaintiff's wells or to subsurface formations.

2. Centerpoint Energy Houston Electric, LLC v. Gulf Coast Coalition of Cities, 252 S.W.3d 1 (Tex. App.—Austin 2008, no. pet.).

Issue: Calculating the valuation of stranded costs recoveries for unbundled Texas utilities.

As part of the 1999 deregulation of Texas's electricity sector, the Texas Legislature enacted a statutory scheme to allow utilities to recover "stranded costs." These are costs incurred through investment in generation-related assets that would have been recovered in a regulated market through rate adjustments but are unlikely to be recoverable at competitive rates.[2] The Texas Public Utilities Commission ("PUC") makes determinations on companies' stranded costs through "true-up" proceedings. These determine the stranded costs a company can recover based on a formula that uses the market and book values of the company's generation assets.

In a March 2004 true-up proceeding, the component companies that formerly made up Reliant Energy (CenterPoint Energy Houston Electric, Texas Genco, and Reliant Energy Retail Services) presented the PUC with an estimate of their stranded costs based on a valuation of Reliant's generation assets. The PUC issued a true-up order in December 2004, in which it determined that the companies (whom the court calls the Joint Applicants) had misapplied some of the statutory measures for market-valuation of generation assets.

Specifically, in valuing their generation assets, the Joint Applicants had used a "partial stock valuation" method, which determines market value by looking at the average daily closing price of a generation company's stock over a period of time. The statute states that a company may use this method when it has transferred its generation assets to a corporation and "at least 19 percent, but less than 51 percent, of the common stock" of that corporation "is spun off and sold to public investors through a national stock exchange."[3]

CenterPoint had distributed 19% of the stock in Genco (Reliant's generation company) to its shareholders in 2002. Much of this had subsequently traded on the New York stock exchange, but some shares had remained in shareholders' retirement accounts or had not traded for other reasons. The PUC ruled that, while the Joint Applicants had partially satisfied the statute by spinning off 19% of generation company

2. *See* Cities of Corpus Christi v. Pub. Util. Comm'n of Tex., 188 S.W.3d 681, 684-85 (Tex. App.—Austin 2005, pet. denied).

3. TEX. UTIL. CODE ANN. § 39.262(h)(3) (Vernon 2007).

stock, less than 19% had been "sold" on a stock exchange. Partial stock valuation thus could not be used.

After deeming partial stock valuation improper, the PUC opted to use its own method to value the Joint Applicant's generation assets. Five valuation methods are given in the Texas statute,[4] but the PUC stated that the Joint Applicants did not meet requisite criteria for any of these methods. Using its own approach to determine market value, the PUC generated an estimate for stranded costs that was lower than the Joint Applicants' valuation by $1.23 billion. As part of its calculation, the PUC deducted from the Joint Applicants' stranded costs the present value of various tax benefits that the Joint Applicants had received as investment incentives when the electricity market was regulated.

The Joint Applicants appealed the PUC's true-up order in district court. They argued, among other things, that the PUC's reading of the partial stock valuation statute was incorrect and that the PUC had exceeded its authority by deducting the present value of their tax benefits. (On the latter point, the Joint Applicants noted that IRS normalization regulations limit the ways in which utilities can pass tax savings on to customers. They argued that the PUC's deduction might result in a normalization violation.) Several of CenterPoint's customers and other interested parties in its service area also intervened, seeking to avoid an increase in rates. The district court upheld much of the PUC order but increased the Joint Applicants' true-up award by $720 million. This ruling was, in turn, appealed in the Third District Court of Appeals in Austin.

The appellate court upheld the PUC's reading of Texas statute as preventing the Joint Applicants from using partial market valuation. It also ruled that the PUC had not exceeded its authority or acted in an arbitrary manner by using its own alternative valuation method to determine the market value of the Joint Applicants generation assets. It said that, while the statute lists specific methods of valuation, these were not necessarily exclusive. Because the Joint Applicants did not meet the criteria for any other valuation method in the statute, the court took note of the "overwhelming statutory mandate that utilities be allowed to recover their stranded costs" and implied it allowed the PUC some leeway to provide the Joint Applicants with an asset valuation and an avenue to stranded cost recovery.

Finally, the appellate court upheld the PUC's decision to deduct the present value of the Joint Applicants' tax benefits. It said such a deduction was reasonable in light of the statutory mandate to prevent over-recovery during the true-up process. The court requested, however,

4. *Id.* at §§ 39.262(h)-39.262(i).

that the district court remand the issue to the PUC to consider a remedy in case the benefit deduction is deemed to be a normalization violation by the IRS.

Additional aspects of the holding (not summarized here) dealt with capacity auction losses and mitigation credits to retail electricity providers. As some of the appellate court's holdings on these issues reversed parts of the PUC order, the appellate court remanded to the district court for further proceedings.

3. BP America Production Co. v. Marshall, No. 04-06-00478-CV, 2008 WL 2828655 (Tex. App.—San Antonio July 23, 2008, no pet.).

Issue: What showing must a party make to assert adverse possession if, after a good faith purchase of interest in a mineral lease, it is determined that one of its predecessors in interest had allowed the interest to terminate?

Between 1973 and 1975, BP America ("BP") obtained several oil and gas leases on the Slator Ranch in Webb and Zapata Counties. The lessors on one of those leases were the Vaquillas, appellants in this case. The Vaquillas lease included a standard "60-day clause," which provided that the lease would not expire so long as the lessee was engaged in drilling or reworking operations designed to produce paying quantities of oil or gas and did not cease such work for more than 60 days.

BP later transferred its interest in the Vaquillas lease to another operator and, after a series of transfers, the interest was purchased by Wagner Oil Company. Wagner was active elsewhere on the Slator Ranch and had previously leased a 50% interest in the undivided minerals of the ranch as a whole.

In a suit brought by the Vaquillas and other lessors, the trial court found that, prior to the transfer of its interest, BP had violated the 60-day clause in its Slator Ranch leases by halting work for a period of several months. The court ruled that BP's lease had consequently terminated.

Vaquillas claimed that, since their lease to BP had terminated before its transfer to Wagner, BP could not legally transfer its interest and Wagner thus had no interest in the lease. The trial court held, however, that Wagner had acquired an interest in the Vaquillas leasehold by adverse possession and as a bona fide purchaser. Vaquillas appealed these holdings.

On appeal, these findings were reversed and the court ruled in favor of Vaquillas. Both parties in the appeal recognized that adverse possession of a mineral leasehold was possible, but the issue in dispute was the degree of adversity that had to be proven. This degree of adversity, the court noted, depends on the relationship of the parties.

Vaquillas argued that the relationship in this case was one of co-tenancy and that a showing of ouster (i.e.,"unequivocal, unmistakable, and hostile acts") was required for Wagner to adversely possess the leasehold. The court noted that a mineral lease does not necessarily make the lessor and lessee "cotenants" because, while a lease is in effect, the lessor has only a royalty interest in the mineral estate and the possibility of reverter. After a lease terminates, the entire mineral estate reverts to the lessor and the lessee maintains no interest at all.[5]

In this case, however, because Wagner already held an interest in 50% of the mineral rights on this lease and other Slator Ranch properties, the court ruled that Wagner and Vaquillas had become cotenants as soon as BP's lease had terminated and the mineral interests in the lease had reverted back to Vaquillas. The heightened standard of adversity for a cotenant was thus required to show adverse possession, but this was not met by Wagner. Thus, the court held that Wagner had not acquired an interest through adverse possession.

The court also overturned the trial court's holding that Wagner had acquired an interest as a bona fide purchaser. It applied the 1936 Texas Supreme Court case *Rio Bravo Oil Co. v. McEntire*, which held that a person cannot be a bona fide purchaser of a mineral interest to which the transferor does not have title.[6] Since BP did not have an interest to convey when it transferred its lease to Wagner's predecessors in interest, Wagner could not have obtained any interest as a bona fide purchaser.

4. Shoreham Oil & Gas Co. v. State, 260 S.W.3d 249 (Tex. App.—Austin 2008, no pet.).

Issue: When can a P-4 Form establish a party's well operator status, its control over the well, and its responsibility for plugging expenses as a matter of law?

In April 1996, Shoreham Oil & Gas Company became the lessee of a gas well, leased for production from the Texas General Land Office ("GLO"). In October 2004, the GLO notified Shoreham that it had forfeited on its lease because it had failed to make royalty payments. The GLO agreed to rescind the forfeiture if Shoreham sold a majority interest in the lease to another company. Prior to closing the sale and transferring operator status, however, it was discovered that the well was leaking gas and condensate. Unsatisfied with Shoreham's efforts to stop the leak, the Railroad Commission of Texas took control of the well and eventually plugged it. In April 2005, the State initiated litigation against

5. *See, e.g.*, Natural Gas Pipeline Co. of Am. v. Pool, 124 S.W.3d 188, 194 (Tex. 2003).
6. Rio Bravo Oil Co. v. McEntire, 95 S.W.2d 381, 382-83 (Tex. 1936).

Shoreham to recover the state funds spent in controlling, cleaning up, and plugging the well.

The trial court granted summary judgment in favor of the State as to Shoreham's status as operator of the well and, after the trial, decided Shoreham was responsible for the well-plugging expenses. On appeal, Shoreham only contested the trial court's summary judgment ruling that it was the operator. The company argued that the trial court had erred in not allowing it to present evidence that it was not the operator at the time of the plugging, and thereby denying it a jury issue on its operator status.

Shoreham had filed two P-4 Forms (certificates of compliance and transportation authority) with the Railroad Commission in 1996 and 2000 respectively. Pointing to its initial 1996 P-4, Shoreham argued that the law in effect until September 1, 1997, should control the determination of its operator status. Pre-September 1997 law, it argued, required the State to establish that a party was in "physical operation and control" of the well in order to show conclusively that it was the "operator."

Because of the P-4 filed in 2000, however, the court said that the more recent law controlled. (It did not reach the question of Shoreham's interpretation of the earlier law.) After September 1, 1997, the Texas Natural Resources Code identifies the operator of a well as the "person who assumes responsibility for the physical operation and control of a well as shown by a form the person files with the commission and the commission approves."[7]

Since the 2000 P-4 clearly identified Shoreham as the operator, Shoreham was found to be an operator, as a matter of law, within the plain meaning of the statute. The district court's ruling against Shoreham was thus affirmed.

7. TEX. NAT. RES. CODE ANN. § 89.002(a)(2) (Vernon Supp. 2007).

B. TEXAS ENERGY SECTOR UPDATE: RED HOT ACTIVITY THAT JUST KEEPS GOING AND GOING AND GOING . . .

COMMISSIONER VICTOR G. CARRILLO*

In 1986 Bruce Willis was starring in *Die Hard*, Guns n' Roses' "Sweet Child Of Mine" was a chart-topping hit, and oil tumbled to under $10 per barrel, having crashed from over $30 per barrel in 1985. What followed was the loss of hundreds of thousands of jobs in the oil and gas sector. It was the perfectly worst time to have graduated with an undergraduate degree in geology and be seeking to launch a career in the oil patch in Abilene, Texas. Such was my plight in the summer of 1986.

In the two decades since the Oil Crash of 1986, I have witnessed tremendous changes in the Texas energy sector, including a remarkable oil price swing resulting in a peak price of over $147 per barrel in the summer of 2008. Several years into a new golden era for the Texas energy sector, industry activity continues at record pace—a pace that would give even Olympic world record sprinter Usain Bolt a run for his money. This article is primarily intended to confirm what many of the readers already know: the Texas oil and gas business did not *Die Hard* in the late 1980s but rather it is back *With a Vengeance*.

Legendary Texas oilman Clayton Williams said this about the energy bust of the late 1980s: "Between the oil price drops and the natural gas chaos, gas pipeline companies and producers went broke across the nation."[8] He went on to say that, "In the oil industry [nationally] we went from 5,000 active rigs to 550. I was a little leaf on a tidal wave." This thought expresses the sentiment of the day for the Texas oil and gas industry in the late 1980s. It is amazing to think that two decades later

* Governor Rick Perry appointed Commissioner Carrillo to the Railroad Commission of Texas in 2003. In 2004, Carrillo won his first statewide election with almost 3.9 million votes, making him the highest-ranking elected Hispanic official in Texas. Carrillo is Chairman of the OCS Policy Committee that advises the U.S. Secretary of the Interior on issues related to oil and gas leasing of the outer continental shelf. Carrillo was recently named to the America's Energy Coast (AEC) Honorary Leadership Council. The AEC educates the public on the importance of the Gulf producing states (Texas, Louisiana, Mississippi, Alabama) for domestic energy security.

8. MIKE COCHRAN, CLAYTIE: THE ROLLER-COASTER LIFE OF A TEXAS WILDCATTER 190 (2007).

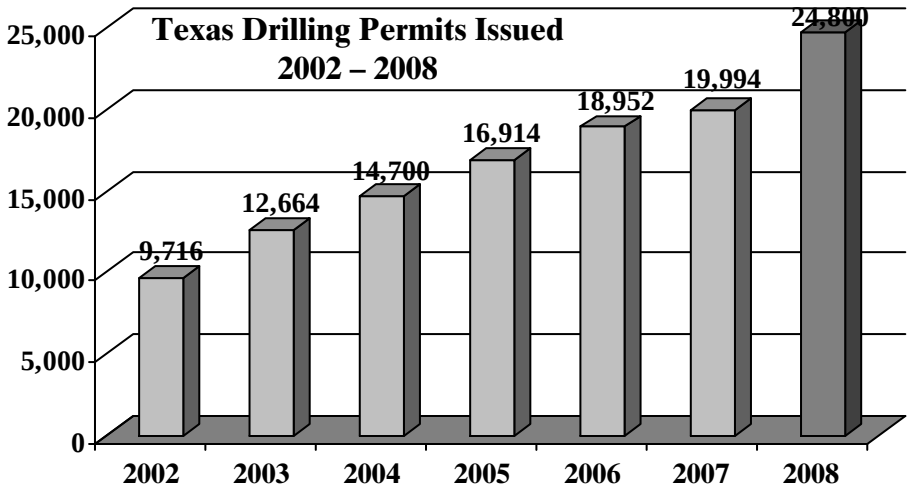
the industry is as vibrant and nearly as active as it has ever been, and a renewed optimism exists about the sector's bright future.

The Railroad Commission of Texas (the "Railroad Commission" or the "Commission") is the primary regulatory agency over the Texas energy sector: oil and gas, pipeline safety, surface mining, and natural gas utilities. This report is meant to give the reader an insight into the new level of activity that the Commission is experiencing as well as explore the resulting challenges and potential solutions.

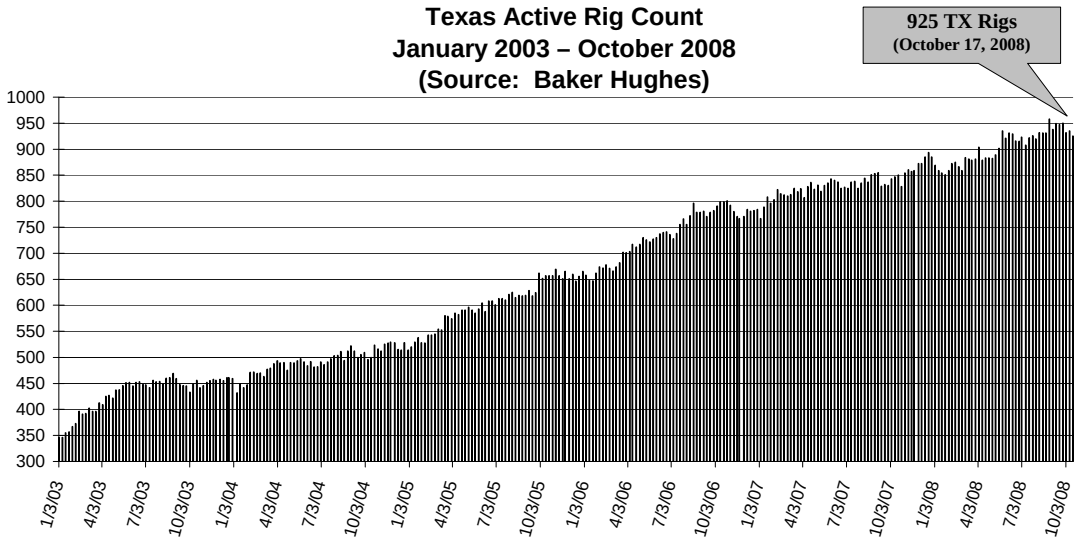
I. OIL & GAS PERMITTING

Times are indeed extraordinary in the Texas energy sector in 2008 with oil and gas activity at levels not seen since 1985. Because every oil and gas well drilled in Texas first requires a Railroad Commission permit, a key measure of industry activity is the drilling permit trend. The Railroad Commission's application to drill, re-complete, or re-enter a well is known as a W-1. In 1999, the Commission issued 8,430 W-1's—the lowest number of permits issued since before 1960. This number represented the bottoming out of a decrease in oil and gas activity that began in 1986 after the price of oil experienced a precipitous drop of approximately 60% in only a few months. In Texas, as a result of the price collapse, the number of permits issued dropped by nearly 50% from 1985 to 1986.

The new millennium brought with it a renewed interest in oil and gas exploration. Since 2000, with the exception of 2002, the number of permits issued has steadily risen. Over the last six years, the number of drilling permits issued has more than doubled from 9,716 to 19,994. For 2008, we project that almost 24,000 drilling permits will be issued—a 20% increase from 2007.



Another key measure of industry activity is the active rig count. Since January of 2003, when there were approximately 350 active rigs in Texas, the trend has steadily increased over the last five years. As of September 12th (before the arrival of Hurricane Ike), there were 949 active rigs operating in Texas. Out of the 2,031 active rigs operating in the nation, almost half (47%) are operating in Texas.[9]



Not only are oil and gas wells being drilled in Texas, but also injection and storage wells. Injection wells and storage facilities, called H-1A's and W-14's, respectively, are a vital part of the prosperity of the Texas energy sector. A sampling of recent injection well and storage facility application activity shows significant growth of approximately 37% over the last three fiscal years:

- FY05 = 1571 + 347 = 1918 applications
- FY06 = 1629 + 425 = 2054 applications
- FY07 = 2253 + 381 = 2634 applications

II. ADMINISTRATIVE COMPLIANCE AND FIELD OPERATIONS

Another area of concentrated growth for the commission is in the administrative compliance end of the business. Our agency mission statement states that: "We serve Texas by our stewardship of natural resources and the environment, our concern for personal and community safety, and our support of enhanced development and economic vitality

9. *See* Baker Hughes, Investor Relations—Rig Counts, North America Rotary Rig Count: Current and Historical Data, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm (follow North America Rotary Rig Count hyperlink about halfway down the page to view spreadsheet) (last visited Sept. 12, 2008).

for the benefit of Texans." It is our role as a regulatory agency to not only assure the safe and environmentally sound exploration and production of our natural resources, but also to avoid being a hurdle whose bar is so high that we effectively stall the development of new discoveries or enhanced production.

Over the last several years, Commission staff has seen a large increase in the amount of work associated with increased drilling activity (alternative casing requests, casing/cementing problems during drilling, complaints associated with drilling in close proximity to urban areas, and a substantial increase in the filing of completion forms associated with new drills and re-completions). Note the chart below. Completion forms require technical and administrative review in the district office before they are sent to Austin. This is done to ensure that the wells are properly cased and cemented and also to ensure the forms are complete.

	Wells Monitored
2003	355,901
2008 Projected	376,000
	New Wells Built
2003	9,447
2008 Projected	14,000
	W-10 Well Tests
2003	220,842
2008 Projected	229,648
	G-10 Well Tests
2003	141,064
2008 Projected	204,566
	P-4s Updated Manually
2003	26,767
2008	37,410
	Surface Casing Jobs
2003	8,107
2008	15,589

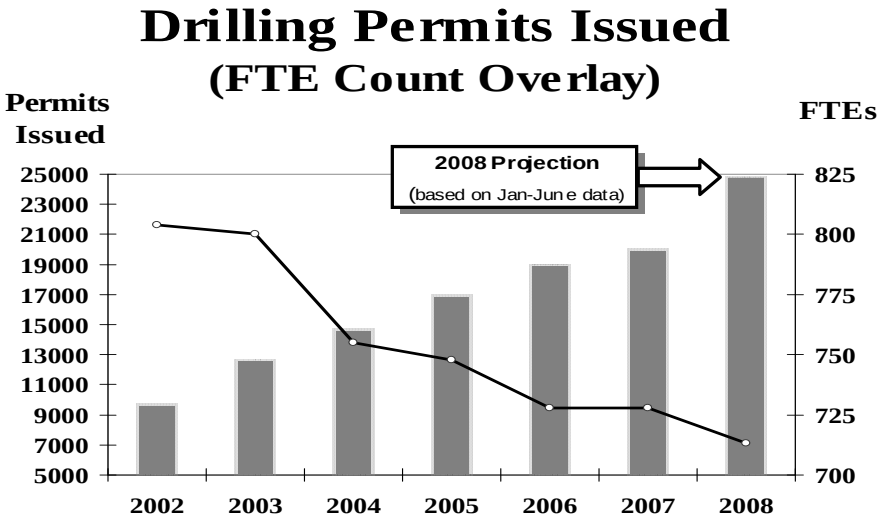
As a result of record industry activity, the agency is experiencing significant backlogs in various areas. The following statistics from the end of August (FY 2008) illustrate the problem:

- Non-expedited drilling permit process time: 40 days
- Expedited drilling permit process time: 14 days
- Pending permit backlog: ~2,400
- Completion packet backlog: ~6,000

- Over 8,000 pending files in Environmental Permits
- Over 10,000 damage reports in the Safety Division

A recent internal report by our Executive Director finds that, "at current staff levels, the demand to process completions timely cannot be met on a statewide basis. Until staffing levels are increased to reflect the magnitude of our vast responsibilities, our function in the field will continue to be governed by 'reactive' activities rather than 'proactive' activities."

A quick look at the following graph, which overlays the total agency full-time employee ("FTE") count on the drilling permit chart, brings the problem into stark focus: the agency is experiencing record levels of work with fewer and fewer total employees to carry out that work.



Technological advances in directional and horizontal drilling, hydraulic fracturing, seismic imaging, and other techniques have resulted in new conventional and unconventional resource development throughout the state. However, this new technology along with drilling activity in populated areas, such as in the Barnett Shale play in North Texas, will undoubtedly result in an increasing demand on Commission staff. More field time will be spent observing critical jobs related to public safety and protection of the environment, such as well plugging, surface casing jobs, spill response, inspecting hydrogen sulfide facilities, inspecting injection and disposal wells, witnessing mechanical integrity testing, and responding to citizen complaints.

Another growing concern is the increasing number of aging wells, particularly those drilled over twenty-five years ago. Wells over twenty-

five years old have a greater tendency to experience issues requiring remedial work, Commission oversight, or both. In 1999 there were 37,457 wells older than twenty-five years. In 2005 that number increased by 57%, to 58,864 wells. The inventory of wells over twenty-five years old will likely trend significantly upward in the next few years because from 1983 through 1985 the Commission issued 113,935 drilling permits. It is also important to note that the number of inactive, shut-in wells has remained fairly constant at around 110,000. On a strong positive note, the inventory of orphaned, abandoned wells has been steadily reduced from almost 18,000 in 2003 to just under 9,750 as of July 30, 2008, as the Commission has overseen the plugging of thousands of these wells over the years.

As activity and workload increase in the field, timely enforcement of rules through field inspections; issuance of violation letters; response to complaints and emergencies such as fires, blowouts, and hydrogen sulfide (H_2S) releases; severance of leases; and submittal of enforcement actions will be reduced, unless there is a corresponding increase in staffing levels. In this regard, Field Operations needs additional oil and gas field inspectors, district technical staff (engineers and geologists), and administrative staff to keep up with the increasing workload.

All of this new development creates a strain on skilled technical personnel who are familiar with the Commission's practices, rules, and regulations. At the same time, salary levels for geologists and engineers continue to escalate at record levels. It should come as no surprise that at the very time that we are experiencing significant backlogs, we are also losing highly qualified Railroad Commission technical staff to the red-hot oil and gas industry. From January 1, 2007 through May 31, 2008, the Commission lost over 40 employees to the private sector. The vast majority were technical employees, such as engineers and geologists. Of those leaving, most are leaving for substantial pay increases.

We are also losing employees to other agencies. In the same time period, nineteen Commission employees have gone to other agencies—all leaving for pay increases. It is alarming to know that almost half of the Commission's leadership staff has either retired and subsequently been rehired or is now eligible to retire. Further, an additional 43% of our leadership will be eligible for retirement within the next five years. Potentially, this leaves only about 9% of our current leadership intact by 2013. Thus, in the next few years, we will be left with a significant void from which we would normally recruit the future ranks of leadership.

III. POTENTIAL SOLUTIONS

There are no easy answers to quickly address the growing backlogs and current and future staffing level problems that the agency is facing. As I

see it, it is essential for us to use every available resource and attack the problem simultaneously from multiple fronts. I am a firm believer that efficiencies can be gained in many areas of the agency. To that end, I have and will continue to reevaluate every aspect of agency practice and procedure in order to be a good steward of the tax dollars entrusted to the agency. However, any belief that we can simply do more with less or create efficiencies to completely offset this record growth in industry activity is nothing more than wishful thinking. It will take real solutions, involving increased staff levels and funding, to allow us to keep up with this torrid pace of activity. In the upcoming Texas Legislative Session that begins in January, we will seek legislative support for additional technical staff positions and a budget increase to more adequately compensate our key technical staff. In addition, we will immediately seek additional revenue to address the key agency backlogs.

As a statewide elected official over the Texas energy sector, I remain committed to ensuring that Texas remains the premier energy producing state in the nation. In 2007 Texas produced almost 7 trillion cubic feet of natural gas—about 33% of the nation's total domestic natural gas marketed production. We will weather this storm and emerge even stronger, and the Texas energy sector will continue to be a key contributor to the domestic energy security of our nation.

III. RECENT DEVELOPMENTS IN UNITED STATES ENERGY LAW

A. Federal Oil, Gas, and Energy Case Summaries

1. Morgan Stanley Capital Group v. Public Utility District No. 1 of Snohomish County, Washington, 128 S. Ct. 2733 (2008).

Issue: Does the Mobile-Sierra doctrine` require an initial FERC determination before a presumption will apply that rates are "just and reasonable"? Are buyer challenges to rates reviewed under the same standard as seller challenges?

Under the *Mobile-Sierra* doctrine, the Federal Energy Regulatory Commission ("FERC") must presume that rates set in freely negotiated wholesale-electricity contracts meet the "just and reasonable" requirement imposed by the Federal Power Act ("FPA").[10] This presumption may be overcome only if FERC concludes that the contract seriously harms the public interest.

The respondents in this case were several western utilities that had purchased power from the petitioners, Morgan Stanley, under long-term contracts during the tumultuous period for West Coast electricity rates in 2000 and 2001. The contracts included rates that were very high by historic standards but lower than what was available in the spot market.

The respondents had asked FERC to modify their contracts, contending the rates should not be presumed to be "just and reasonable" under *Mobile-Sierra* because FERC had never given the rates initial approval. They also argued that, even if *Mobile-Sierra* did apply, the contract rates were so high that they violated the public interest, so that a contract modification should be ordered. An administrative law judge and FERC both ruled that the *Mobile-Sierra* presumption did apply to the contracts and that the contract rates were not contrary to the public interest. FERC thus refused to intervene to revise the contracts.

The respondents appealed in the Ninth Circuit, which reversed and remanded the FERC ruling. The Ninth Circuit held (1) that contract rates must be reviewed before the *Mobile-Sierra* presumption will apply, and (2) that, to prevail in a contract rate challenge, a wholesale electricity purchaser needed only to meet the lower standard of showing that rates exceeded a "zone of reasonableness," not the more demanding "public interest" standard that it said applied to sellers. Morgan Stanley appealed this decision.

10. *See, e.g.,* Fed. Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348, 354-55 (1956).

In a majority opinion by Scalia, the Supreme Court disagreed with the Ninth Circuit, stating that rate contracts did not require an initial FERC conclusion of fairness and reasonableness before the *Mobile-Sierra* presumption would apply. It made the qualification, however, that FERC had ample authority to set aside contract rates if there was evidence of unfair dealing, fraud, duress, or other illegal activity at the contract formation stage.

The Court also rejected the Ninth Circuit's holding that a less demanding "zone of reasonableness" test should apply under a *Mobile-Sierra* presumption when electricity buyers challenge rates. It ruled that the standard for a buyer's challenge is the same as for a seller's challenge: to be overturned, the contract rates must seriously harm the public interest. The court agreed with the Ninth Circuit that the three seller-focused criteria from *Sierra* for being "harmful to the public interest"—that rates impair the financial ability of the public utility to continue its service, that they cast an excessive burden on other consumers, or that they are unduly discriminatory—were not the exclusive components of such a showing. In a buyer's rate challenge, the Court allowed that different criteria could be used, such as showing that the buyer's customers would be harmed.

Despite disagreeing with the Ninth Circuit's two primary holdings, the Court upheld its decision to remand the case for further consideration by FERC because it stated there were two errors in FERC's analysis. FERC may have only considered the immediate effect of rates on consumers and thus failed to look far enough "down the line" in determining whether the contract rates would impose an excessive burden on consumers. The Court also asked FERC to undertake further investigation into the respondents' allegations that petitioners had engaged in unlawful spot market manipulation. The Court said that illegal activity in the spot market by one party does not necessarily mean that the *Mobile-Sierra* presumption should not apply to futures contracts. However, if illegal activity is found to have had a causal relationship with the rates agreed to in the futures contracts, the contract rates should not receive a presumption of reasonableness under *Mobile-Sierra*.

2. Natural Resources Defense Council v. E.P.A., 526 F.3d 591 (9th Cir. 2008).

Issue: Were EPA regulations, which exempted oil and gas construction sites from Clean Water Act permitting requirements for storm water discharges of sediment, a permissible agency interpretation of the Energy Policy Act of 2005 and existing law?

The Energy Policy Act of 2005 amended the Clean Water Act ("CWA") to include oil and gas construction sites among the activities

that received certain exemptions from storm water runoff permitting requirements. To implement this change, the Environmental Protection Agency ("EPA") promulgated new regulations in 2006. The regulation relevant to this case effectively stated that storm water runoff from oil and gas construction sites would not trigger a CWA permit requirement, even if it caused a water quality standard violation, as long as sediment was the sole contaminant.[11]

The Energy Policy Act did not specifically mention "sediment" in its provision regarding storm water permitting. The EPA noted, however, that sediment is the pollutant most commonly associated with construction activity and reasoned that it was Congress's intent to include sediment in the types of pollutants exempted from permitting requirements for oil and gas construction sites. Without such a construction, the EPA believed the Energy Policy Act's amendment to the CWA would be "effectively meaningless."

Natural Resources Defense Council ("NRDC") petitioned the Ninth Circuit to review the EPA's interpretation of the legislation. NRDC contended that the EPA rule exempting sediment runoff from permitting requirements was an impermissible interpretation of both existing law and the amendments made in the Energy Policy Act.

The Ninth Circuit applied the two-step test from *Chevron* to review the EPA's construction of the statute.[12] The test looks, first, to whether the legislative language is ambiguous or whether Congress has left a gap for the agency to fill. If that is the case, the *Chevron* test looks next to whether the agency's action is based on a permissible construction of the statute, i.e., one that is not arbitrary or capricious.

The court found that the Energy Policy Act's amendment to the CWA was ambiguous and that it was silent on the issue of sediment, but it ruled that the EPA's interpretation of the Energy Policy Act amendment was arbitrary and capricious because it contravened previous EPA policies and interpretations of relevant legislation. Consequently, the court vacated the EPA's regulation and remanded the issue to the EPA for further proceedings.

11. *See* 40 C.F.R. § 122.26(a)(2)(ii) (2007).
12. *See* Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837 (1984).

3. Maine Public Utilities Commission v. FERC, 520 F.3d 464 (D.C. Cir. 2008).

Issue: Can a negotiated settlement apply the Mobile-Sierra doctrine's presumption of reasonableness to energy rate challenges by non-settling third parties?

In June 2006, the Federal Energy Regulatory Commission ("FERC") approved a 115-party settlement agreement aimed at ending problems in the New England region's electricity capacity market. The settlement's terms included the creation of a forward capacity market, which utilized auctions to sell forward capacity with a three-year lead-time. The agreement called for certain "transition payments" to be paid to generators during the period between the first auction and the delivery of the first forward capacity in 2010.

The settlement stipulated that any challenges to the transition payments or to the final prices from the forward market auctions would be judged under the *Mobile-Sierra* doctrine's "public interest" standard (i.e., FERC would enforce the agreed-to payments and auction prices unless the public interest required otherwise because they financially impaired a utility's ability to continue service, cast an "excessive burden on customers, or were unduly discriminatory). Under the terms of the settlement, this standard would apply whether the challenges were brought by a settling party, by a non-settling party, or by FERC sua sponte.

Maine's Public Utilities Commission ("PUC") and the attorneys general of Connecticut and Massachusetts, all of whom were non-settling parties, petitioned the D.C. Circuit to review FERC's approval of the settlement. The petitioners brought several claims concerning FERC's approval of the settlement and transition payments system, but the D.C. Circuit only agreed to review the claim that FERC's acceptance of the *Mobile-Sierra* provision was unlawful because the provision imposed the deferential "public interest" standard on non-settling parties. This was a question of first impression for the court.

The D.C. Circuit noted that, in general, FERC applies a "just and reasonable" standard in hearing rate disputes. Under this standard, if the Commission decides a disputed rate is unjust, unreasonable, discriminatory, or unduly preferential, it can set rates at a level that it determines to be "just and reasonable." The *Mobile-Sierra* doctrine carves out an exception to this only when parties have freely negotiated a contract or settlement regarding the rates in dispute. In such cases, the court said *Mobile-Sierra* seeks "to preserve the benefits of the parties' bargain as reflected in the contract, assuming that there was no reason to question what transpired at the contract formation stage."

Non-settling parties have by definition objected to the benefits of the bargain, however, and the court reasoned they should not be bound by it. Consequently, it held that "when a rate challenge is brought by a non-contracting third party, the *Mobile-Sierra* doctrine simply does not apply; the proper standard of review remains the 'just and reasonable' standard in section 206 of the Federal Power Act." The court thus remanded the issue of the settlement agreement's *Mobile-Sierra* provision to FERC for further consideration.

B. AN EMPIRICAL ANALYSIS OF STATE ETHANOL PRODUCTION INCENTIVES: DO THEY WORK?

PABLO A. ORMACHEA*

I. INTRODUCTION

As the price of oil remains near record levels, hovering around $100 per barrel, domestic initiatives to develop sustainable renewable energy sources have also grown exponentially. Ethanol, one of the most highly touted alternative fuel sources, has been the target of all sorts of legislation all over the world. In 2007, the United States Senate passed a bill mandating the production of 36 billion gallons of ethanol by 2022—a sevenfold increase over current levels—and an acceleration of the federal ethanol incentive program that has already paid out $10 billion and counting.[13] That same $10 billion could put over 400,000 students through

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13. Gary Libecap, *Agricultural Programs with Dubious Environmental Benefits: The Political Economy of Ethanol, in* AGRICULTURAL POLICY AND THE ENVIRONMENT 89, 93 (Roger E. Meiners & Bruce Yandle eds., 2003).

four years at a public university[14] or match a full year of global humanitarian assistance from the entire international community.[15] At the state level, many governments are equally determined to promote ethanol production. Each state has followed different paths, some relying on outright grants, others on low-interest loans or modifications to the tax laws, while some states have no incentives at all.

But do the incentives work? No one has ever systematically examined how, or even whether, a state's production incentives have a demonstrable impact on its ethanol production capacity. The availability of federal incentives in every state—and the resulting lack of a control group—makes it impossible to assess their impact. Fortunately, the different strategies pursued at the state level provide a tremendous amount of data without a similar barrier to analysis.

This article is an empirical research project that attempts to answer that question by creating an original database consisting of data about state ethanol incentives and production totals from 2002 to 2007. The article proceeds in four parts. Part II begins by recounting the beneficial treatment ethanol has received in recent U.S. history. Part III explains the project's methodology. Part IV describes the most striking findings, and Part V evaluates those findings.

Empirical studies assessing the impact of legal incentives in any arena are few and far between, though notable examples do exist outside of legal academia.[16] Perhaps because the reemergence of ethanol as a major player in the discourse of alternative fuels is a relatively recent phenomenon, empirical studies of the effect of ethanol incentives appear to be non-existent, making this study the first of its kind.

Originally, the research project was intended to assist lawmakers in structuring future incentives to maximize returns and best develop or expand a given state's ethanol production capacity. The results, however, ask whether *any* state ethanol production incentive is worth the cost. Most incentives take the form of tax credits, loans, or grants, but regardless of magnitude, no type of incentive has a strong, statistically significant impact on the ethanol production within the state. Instead, the single largest factor influencing the increase in ethanol production lies largely outside of the legislature's control: the state's production of corn.

14. CollegeBoard.com places the average cost of attendance of a public university at $6,185 per year. CollegeBoard.com, 2007-2008 College Costs, http://www.collegeboard.com/student/pay/add-it-up/4494.html (last visited Nov. 5, 2008).

15. GLOBAL HUMANITARIAN ASSISTANCE, AN INDEPENDENT REPORT ON HUMANITARIAN AID FLOWS (2003), http://www.globalhumanitarianassistance.org/ghafr2003.htm (last visited Nov. 5, 2008).

16. *See, e.g., Eric M. Engren et al., Do Saving Incentives Work?,* BROOKINGS PAPERS ON ECONOMIC ACTIVITY 1994 pt.1, at 85.

This article does not take a stance on the merits of ethanol. Instead, it focuses on assessing the effectiveness of state ethanol incentives to aid legislative decision-making.[17] Politicians often tout their state as a prime location for investment in renewable energy, and they deploy sophisticated investment incentives to encourage private development.[18] The discourse, however, lacked actual statistical evidence of the efficacy of their incentive programs. This article hopes to fill the void.

II. BACKGROUND

Critics of the ethanol industry decry the immense lobbying power of the Renewable Fuels Association and vilify Archer Daniels Midland, producer of about 50 percent of the 2000 ethanol market,[19] and Cargill. Others express doubt about the viability of ethanol, with its most ardent critics arguing that ethanol is nothing more than "unsustainable, subsidized food burning" and an "abuse of our precious croplands to grow an energy inefficient process."[20]

Proponents take a different view. Not only has ethanol been advertised as having significant environmental benefits and promoting energy independence, but it also has the extra political capital of assisting Midwestern farmers[21]—"a well-established, concentrated political constituency."[22] Indeed, Richard Gephardt, former Democratic leader of the House of Representatives, has proclaimed that "[e]thanol is good for our environment, our nation's energy security, and for American farmers."[23] And so far, the federal government has spent at least $10 billion in ethanol subsidies.[24]

The $10 billion seems to have had an effect. No doubt thanks to the sustained funding from the Department of Energy, the price of a gallon of ethanol dropped from $4.63 in 1980 to $1.22 in 1999. Even though the

17. The use of financial incentives to encourage ethanol production is not a recent phenomenon. *See, e.g.,* MONT. CODE ANN. § 15-70-522 (1983).

18. Florida Governor Charlie Christ "has made clean energy one of his signature issues." Zac Anderson, *Renewable Energy a Legislative Priority,* SARASOTA HERALD TRIB., Mar. 13, 2008, at BM1, *available at* http://heraldtribune.com/article/20080313/NEWS/803130418/-1/newssitemap. (The article explains that the Governor has included a $100 million grant proposal to increase renewable energy production (funding an ethanol production facility could benefit from), but according to the study, the grant would likely have a negligible effect on actual production, insofar as ethanol is concerned.)

19. Julie Forster, *Betting the Farm on Ethanol*, BUS. WK., Jun. 2001, at 41.

20. *See* Libecap, *supra* note 13, at 89 (quoting David Pimentel, Prof. of Ecology and Agric. at Cornell Univ.).

21. The industry's proponents argue that the ethanol program boosts the annual income of a typical Midwestern family by about $15,000. ETHANOL REPORT (Renewable Fuels Ass'n, Washington, D.C.), May 7, 1998.

22. *Id.*

23. *Id.* at 2.

24. *See* Libecap, *supra* note 13, at 89.

drop in cost already had some people hoping for a halt to incentives in 1999,[25] others continue to call for additional ethanol incentives.[26]

III. METHODOLOGY

This paper is the first empirical analysis of state ethanol production incentives and uses the production data and relevant statutes from all fifty states to examine whether, and to what extent, the presence of an incentive impacted that state's production capacity. Specifically, it hopes to answer three questions:

1. Does the mere presence of a particular type of incentive, or any incentive at all, affect a state's production of ethanol?
2. Does the dollar amount affect the impact of each type of incentive?
3. Does state corn production, rather than legislative incentives, affect a state's production of ethanol?

For each question, a state's production of ethanol was measured twice: absolute number of barrels and absolute number of refineries. Measuring production in two different ways allows for an assessment of whether legislators may have sought to "create jobs" rather than increase production.

A. Data Sets

The data in this analysis is derived from three sources: an index of state incentives available through the U.S. Department of Energy, ethanol production totals from the Renewable Fuels Association's Annual Industry Outlooks, and corn production data from the U.S. Department of Agriculture.[27] The three sources are discussed below.

25. Charles Wyman, *Biomass Ethanol: Technical Progress, Opportunities, and Commercial Challenges,* 24 ANN. REV. ENG. & ENV'T 189, 189 (1999) (calling for making ethanol "competitive as a pure fuel without subsidies").

26. Sanya Carleyolsen, *Tangled in the Wires: An Assessment of the Existing U.S. Renewable Energy Legal Framework*, 46 NAT. RESOURCES J. 759, 764-65 (2006) (internal citations omitted) ("The legal system needs to protect and encourage private investment in [renewable energy technology] systems.").

27. The United States Department of Energy, Alternative Fuels & Advanced Vehicles Data Center compiled a 50-state survey of state laws and incentives promoting the use of alternative fuels. "The educational tools and information featured in the AFDC are geared toward helping consumers and fleets reduce petroleum consumption." About the AFDC, *available at* http://www.afdc.energy.gov/afdc/about.html (last visited Nov. 5, 2008); Alternative Fuels & Advanced Vehicles Data Center, http://www.eere.energy.gov/afdc/incentives_laws.html (follow "List All States – Alternative Fuel Vehicle Incentives And Laws" hyperlink located towards the bottom of the page under the map) (last visited Nov. 5, 2008).

1. Department of Energy Index

Many states classify their laws by subject matter, and their legal code-based system allows independent verification of each incentive listed in the Department of Energy ("DoE") index. If a state categorizes its legal code, it allows for an additional search for other incentives not included in the DoE database.[28] Incentives "buried" in other states' non-categorized code, however, may have been missed.[29] During the verification process, I also supplemented the index with historical data, such as dates of original enactment. Incentives were ignored only in the rare event that the law could not be independently verified.[30]

The scope of the database was limited in two different ways. First, federal incentives were eliminated. The availability of federal incentives in every state—and the resulting lack of a control group—makes it impossible to assess their impact. Excluding the federal incentives from the analysis, however, should not skew the results because there is no reason to suppose that federal incentives have a disproportionate impact on certain states, given that private actors can avail themselves of the same federal incentives, regardless of state location.

Second, the database does not include incentives that were not directly targeted at expanding or creating production facilities. Incentives that may have bolstered ethanol production by increasing demand in the consumer market (e.g., incentives offering tax benefits to individuals purchasing ethanol-ready vehicles) were excluded to create a more manageable database focused entirely on the effect of "primary" production incentives. While it was easy to apply this rule to most incentives—such as those dealing with defraying the cost of converting a vehicle to alternative fuels—others were not as clear-cut. The database errs on the side of under-inclusiveness and does not include incentives similar to South Carolina's income tax credit that promotes only "qualified research and development."

28. *See*, *e.g.*, WASH. REV. CODE § 82.04.260 (2008).

29. The absence of uncovered incentives should not impact the results of the study. The incentives that were included did not generally correlate with a statistically significant rise in ethanol production. The impact would only be further diluted by incorporation of additional incentives into the quotient. If the database hypothetically reflects only 95% of the relevant state incentives but captures 100% of ethanol production, it attributes a greater correlative link to the statutes than if diluted to a 1:1 ratio. Of course, the major findings would be further bolstered by more exhaustive research uncovering potentially missed legislation.

30. For example, the Department of Energy database contains a 1988 Iowa law that I was unable to verify independently.

2. Renewable Fuels Association

Data on individual state production capacities was surprisingly scarce. Although figures are readily available for national ethanol production,[31] it was much more difficult to find a state-by-state breakdown of the data. Ultimately, the database relies upon the data collected by the Renewable Fuels Association ("RFA") in their Annual Industry Outlooks.[32] The year 2002 serves as the starting point for the analysis in large part because it was the year the first RFA Outlook Report was released. The data is used not only for the production capacities of individual states, measured in barrels of ethanol, but also for the number of refineries in each state[33]—given that some legislators might care more about creating jobs by increasing the number of refineries within the state than about the number of gallons produced. Importantly, relying on a single source helped ensure consistency in the data across states. Relying exclusively on the RFA Outlook Reports had one more advantage: they include facilities still under construction in computing state ethanol capacity. In other words, the RFA Outlook Reports immediately capture industry responses to changing legislation with minimal delay for new projects.

3. Variables

As indicated above, the overriding goal in the research project was, first and foremost, to examine whether state incentives have had *any* demonstrable effect on actual production figures. To answer these questions, the database was coded for the presence and dollar amount of the following variables:

1. Flat grants or tax credits
2. Low or no-interest loans
3. Per gallon tax credits

31. *See, e.g.,* U.S. Energy Info. Admin., EIA-819 Monthly Oxygenate Report, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/monthly_oxygenate_telephone_report/motr.html (last visited Nov. 5, 2008).

32. Relying upon one source alone instead of potentially conflicting datasets served to control for reporting error between various data sources. For example, another potential data source was a database provided by the State of Nebraska available at http://www.neo.ne.gov/statshtml/121_archive.htm. I ultimately used the RFA figures because those are what Nebraska purported to rely on for *their* data (though the figures are at times conflicting) and because the record extended to 2002, not just 2005. The U.S. Department of Agriculture provided national statistics for ethanol production divided into geographic regions, but not states, which did not fit the purposes of this study.

33. The RFA in years 2002-2007 signified, but made no distinction between, actual production capacity and production capacity/facilities that were under construction as of the time the reports were made. For purposes of the analysis I included actual *and* under-construction estimates of both production capacities and numbers of refineries per state. This decision means that the database captures immediate responses to changing legislation by including construction totals in measuring total production capacity.

4. Tax deductions[34]
5. Other[35]

The database has been coded for these variables for every state from 2002 to 2007. With this data, it becomes a simple matter to create a dummy variable to run additional regression analyses on whether the mere presence of any incentive—regardless of type or dollar amount—affected the state's production.

B. Judgment Calls

No two states offered identical, or even identical types of, production incentives.[36] Production incentives range from the common tax credit for each gallon of ethanol produced to some truly creative mechanisms, such as a complicated wage garnishment reimbursement system for employees of renewable fuel-production facilities.[37] Originally, the research project attempted to categorize production incentives according to incentives offering tax credits, grants, loans, and per-gallon subsidies. I was forced to add a fifth classification, a 'miscellaneous' category, after finding that the state legislatures are infinitely more creative than any rigid classification system in their attempts to bolster ethanol production.

Because the cost of a facility varies so dramatically depending on the scale of the project, it was impossible to estimate meaningful figures for incentives that repay based on a percentage of construction costs. Therefore, incentives based on a percentage of start-up costs are included only in analyses assessing whether the mere presence of the incentive had an effect.

The database includes exact dollar figures wherever the law stated them. Unfortunately, not all incentives clearly explained the full dollar amount available. The per gallon tax credit incentives are at one end of the spectrum, with well-defined, per-gallon dollar amounts that were simple to add to the database.[38] Other incentives, chiefly loans or grants, are on the other end of the spectrum, and their lack of clarity forced a

34. Surprisingly, only three states, Montana, New Mexico, and Washington, offered tax deductions as opposed to credits, with Montana only offering tax deductions starting in 2007.

35. This includes incentives that do not readily fit into the first four categories, like Kentucky's wage garnishment system that allows a refinery to keep up to four percent of an employee's salary, all reimbursed by the state.

36. I also limited the scope of the inquiry to incentives that explicitly fostered ethanol production. Many statewide incentives could, conceivably, have affected production by increasing demand at the consumption level. For example, many states offered tax incentives for vehicles capable of running purely on renewable/biofuels. *See, e.g.,* OKLA. STAT. tit. 74 § 130.4 (2008). I operated under a presumption that explicitly production-based incentives affected production levels more than second-degree, consumption-targeted legislation.

37. *See, e.g.,* KY. REV. STAT. ANN. §§ 141.4244-4288.

38. For example, South Dakota offers a $0.20 tax credit for each gallon of ethanol. S.D. CODIFIED LAWS § 10-47B-162.

judgment call. If the law only contained information on the minimum an investor could obtain, then the minimum was used in running the analyses. If the law only contained information on the maximum an investor could obtain, then the maximum was used in the regression analyses.

The difficulties in ensuring dollar consistency across incentive types meant that each analysis was run twice: once looking only at the mere presence of the incentive types and once with the dollar amount available. That means that if a state had two incentives, one of which was categorized as an amount-known tax credit and the other having only a clear maximum, only the clear maximum was used in the second analysis.

C. Selecting Appropriate Index Values

The main hypothesis was that market factors, rather than legislative incentives, serve as the actual driving force behind a state's ethanol production capabilities. The predominant market factor tested, which the results indicate *was* indeed the strongest predictor of a state's capacity for ethanol production, was the state's level of corn production. Each state's corn production data was obtained from the United States Department of Agriculture's National Agriculture Statistics Service.[39]

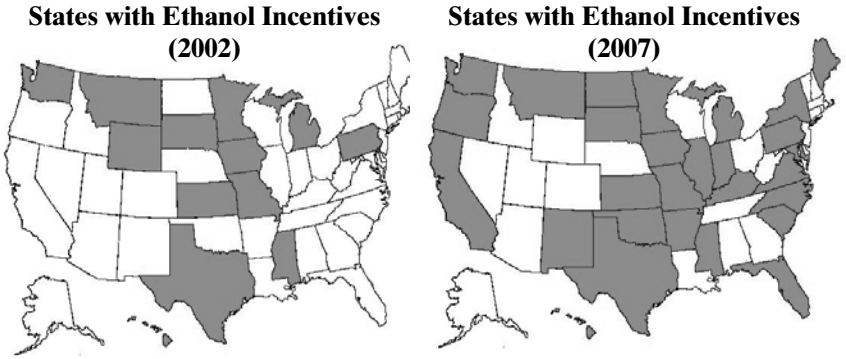
IV. PRESENTATION OF DATA

A. Characteristics of the Database

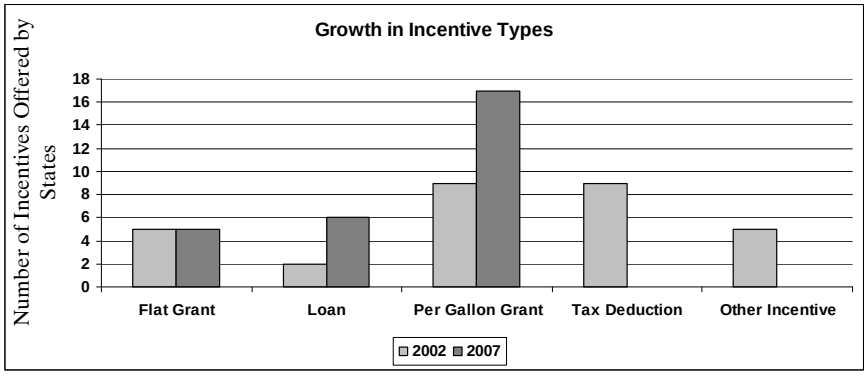
The years 2002 to 2007 saw ethanol become an ever more important part of the national debate on alternative energy fuels.[40] The number of states offering incentives exploded over the six-year period, more than doubling from 13 to 29.

39. U.S. Dep't of Agric., Nat'l Agric. Statistics Serv., Statistics by Subject, http://www.nass.usda.gov/QuickStats/indexbysubject.jsp?Pass_group=Crops+%26+Plants (last visited Nov. 5, 2008)

40. A LexisNexis search for articles with the word "ethanol" in "Major U.S. Newspapers" returned 766 results for 2002 and more than 3,000 results (too many for the search engine to display) for 2007.



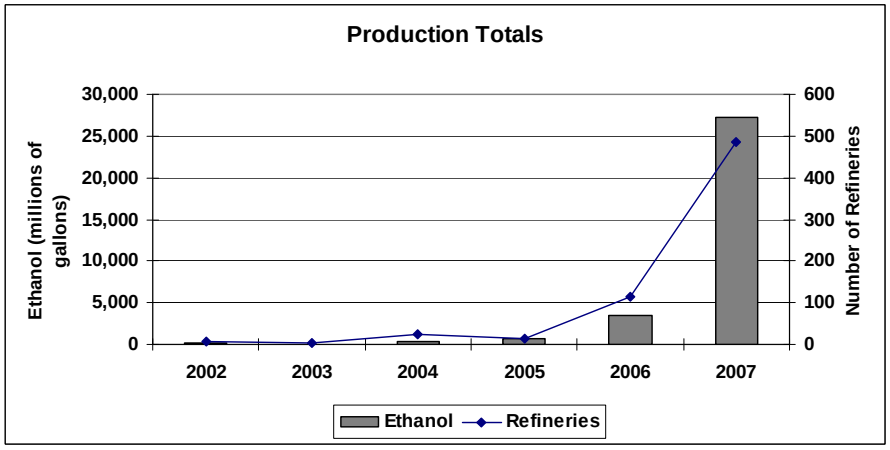
By the end of 2007, the largest number of states chose to stimulate ethanol production through the use of grants or tax credits based on the number of gallons produced. Flat-rate grant incentives enjoyed the greatest rate of increase, spreading from two to eleven states, and three pioneering states introduced the use of tax deductions. A few states chose to ignore other states' incentive programs and blaze their own path by relying on new and creative incentives: for example, Kentucky's law authorizing companies to require employees to pay the company a tax-refundable wage assessment.[41]



Ethanol production totals also increased. During the time period studied, the national production of ethanol more than quadrupled from 2,738 million barrels to 11,622.9 million barrels of ethanol. The number of refineries increased by the lesser, but still astounding, proportion of 230%—indicating that ethanol producers not only invested in more than 100 new refineries but also increased the output of the 79 facilities existing in 2002. Surprisingly, the totals skyrocketed even though the number of states actually producing ethanol changed only slightly from 20 to 24 over the same span. Two states ceased production entirely, and

41. KY. REV. STAT. ANN. §§ 141.4244-4288.

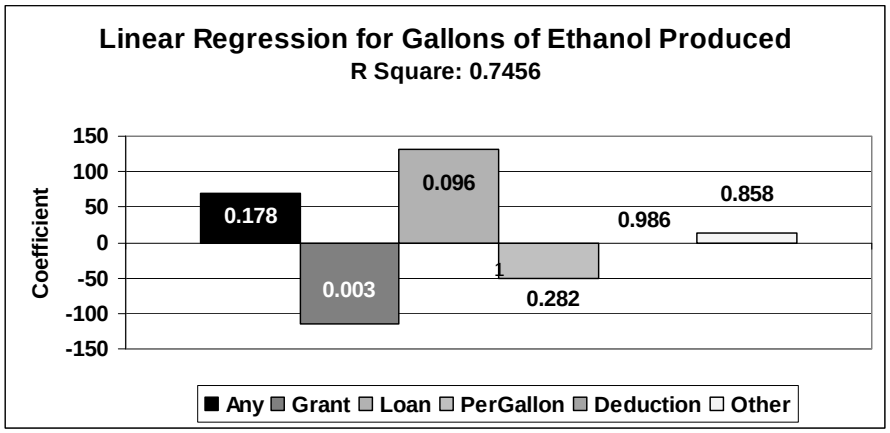
six new states became ethanol producers at some point over the six-year period.



B. The Incentives' Minimal Impact

1. Production capacity defined in gallons

The presence of an incentive, regardless of type, does not have a statistically significant correlation with increased ethanol production. The presence of a grant-based incentive, the only incentive with a statistically significant effect,[42] actually has a *negative* correlation of 114 million gallons. Given the negative effect and the often-staggering amount of money earmarked for the grant programs (North Carolina leads the way with grants of a *minimum* of $140 million each), legislators may be best off ignoring flat grant incentives.[43]



42. P=0.003.

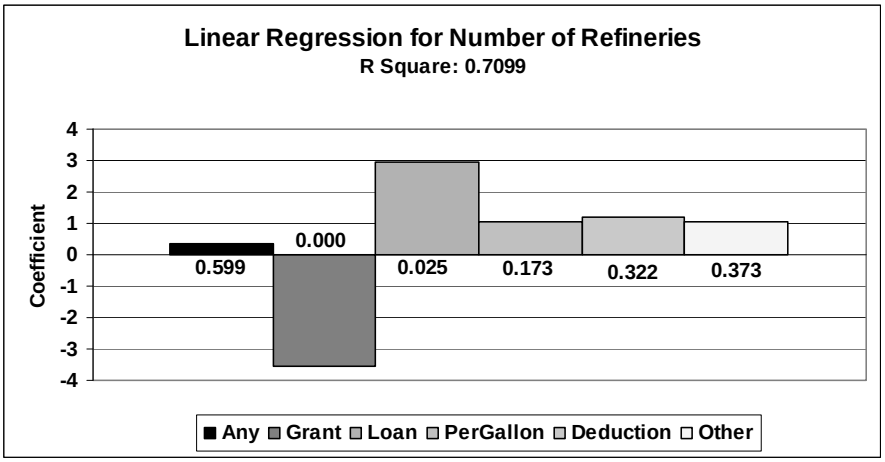
43. North Carolina exemplifies a state attempting to stimulate ethanol production within its borders but with incentives so far failing to have any effect. In 2007, North Carolina had no production facilities and no recorded ethanol production with the RFA.

No other incentive type had a statistically significant correlation. Because the incentives generally failed to have a statistically significant impact on ethanol production, by and large, state legislatures could have better spent their time and money elsewhere.

Rerunning the regression with the dollar amount available, rather than only the presence of incentives, had a similar result. The maximum amount available through a per gallon tax credit program was the only dollar amount that had a statistically significant effect on a state's ethanol production.[44] The findings indicate that a state produced an extra 28.3 gallons of ethanol for every extra dollar it made available in a per gallon tax credit program. If true, then raising the per gallon credit maximum to almost $2 million for *each* ethanol producer within the state would correlate with an increase in production of only 1% of the 2007 national ethanol production total. This high cost for a minimal return should give legislatures pause.

2. Production capacity defined in number of refineries

Only grants[45] and loans[46] had a statistically significant correlation with the number of refineries within a state. Surprisingly, the presence of a grant incentive correlated with 3.54 fewer refineries within the state. Loan incentives had a favorable effect on the number of refineries: the presence of a loan correlated with the presence of 2.95 additional refineries. The mere presence of other types of incentives did not have a statistically significant impact.

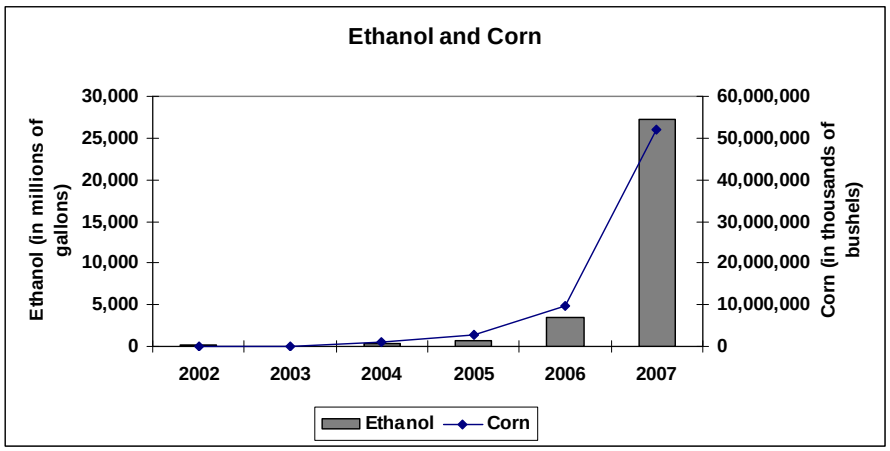


44. P=0.024.
45. P=0.000.
46. P=0.024.

Rerunning the regression analysis with the dollar amount available yielded even more information. Both the loan amount[47] and the per gallon credit maximum[48] had a statistically significant, albeit miniscule, correlation with the number of refineries within a state.[49] If accurate, an additional $5.24 million in a loan program or a per gallon maximum of $170 million for each individual producer would yield only one additional refinery within a state.

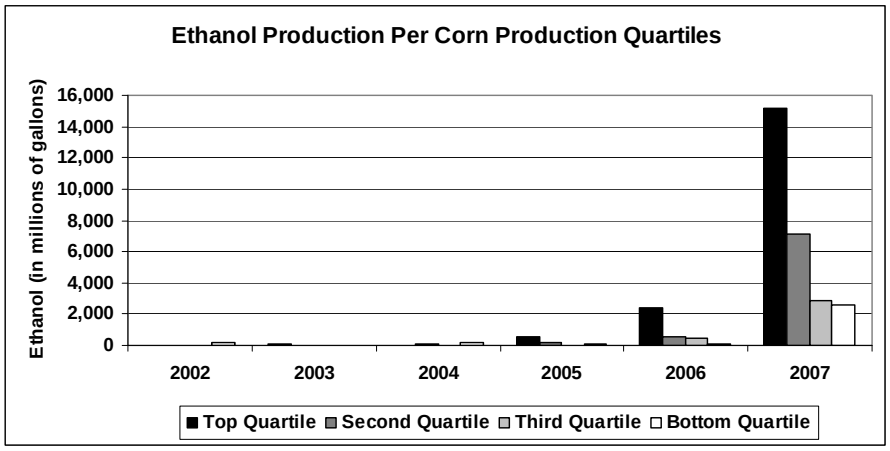
C. Effect of Corn Production

Ultimately, it was the amount of corn harvested within a state that had the greatest correlation with increased ethanol production. At every stage of the analysis, from barrels of ethanol to number of refineries, corn had an unmistakably positive impact.[50] The findings indicate that a state produced 514 gallons of ethanol for every extra 1,000 bushels of corn produced over the relevant time period. The findings also indicate that it produced an additional refinery for every 116,550,000 bushels a state harvested.



The figure below reflects the impact of corn. The top quartile of corn-producing states produced anywhere from 92.38% to 96.69% of the national share of ethanol.

47. P=0.003.
48. P=0.000.
49. The regression returns a loan amount coefficient of 0.000000191 and a per gallon maximum coefficient of 0.00000000588.
50. P=0.000.



This growth was not shared equally, however, among all the states with the largest corn harvests. Illinois, Nebraska, and Iowa, the three states that produce the greatest amount of corn, are also the states responsible for the largest share of ethanol production (with the exception of 2005, when Minnesota edged out Nebraska by 600,000 barrels). Even so, the three states went from a commanding 90.64% of national production to a far less dominant 31.26%. This is not to say that the three states failed to increase ethanol production (Illinois, Nebraska, and Iowa went from producing 2,481 million barrels to 3,634 million barrels, a 28% improvement), but only that they failed to increase as quickly as the other corn-producing states.

IV. CONCLUSION

This article is the first study to empirically examine whether legislative ethanol incentives have a statistically significant impact on production, and it has yielded two striking conclusions. The first finding shows that a given state's incentives (whether to stimulate domestic production and employment or to reduce dependence on hostile foreign powers) do *not* have a significant impact on ethanol production within the state. This result is all the more striking given that national ethanol production did indeed increase by a stunning 424% from 2002 to 2007, or nearly three times the rate of increase for national corn production over the same period.[51] This increase, when viewed in conjunction with the findings, suggests that market demand drives ethanol production, not tax breaks or grants. Alternatively, the impact of the *federal* incentives, which could

51. In 2002, the United States had a production capacity of 2,378 million gallons of ethanol. In 2007 the United States had a production capacity of 11,622.9 million gallons, or an increase of 424%. In 2002, the United States produced 8,966 million bushels of corn. In 2007, the United States produced 13,073 million bushels of corn, or a 145% increase.

not be subjected to statistical analyses for lack of a control group, may be of such a scale that it dramatically outweighs or nullifies the impact of state incentives. The truth likely lies somewhere in the middle, with both market demand and federal incentives playing important roles in fostering the tremendous growth.

The second finding is just as telling: incentives may do nothing to encourage development within a state without access to the source of the renewable energy. For ethanol, the results indicate that access to corn within a state, and not the presence of incentives, has the most impact on the growth potential of the state's ethanol industry. The same may hold true for other competing sources of renewable energy. If so, then state legislators could provide all the incentives in the world, but the industry would still grow only as fast as the raw source allows. State legislators hoping to encourage renewable energy development should consider instead promoting investment in the underlying raw material before committing limited funds to ineffective subsidies or tax benefits.

In other words, it may be the market, and not the politicians, that drives the industry's growth. Ultimately, the results indicate that state governments may be throwing away money to interests already sufficiently motivated by market factors. It remains to be seen, however, whether state ethanol incentives can serve as a "safety net" for the industry if it were to falter. After all, the last six years have been a boom time for ethanol. If oil prices were to dramatically fall, those state ethanol incentives might become all that keeps the industry afloat.

IV. RECENT DEVELOPMENTS IN INTERNATIONAL ENERGY LAW

A. SIGNS OF PENDING LIBERALIZATION IN CHINA'S OIL SECTOR*

STEVE ZHANG** AND PAUL SAYDAK***

> *To sharpen the oil industry's competitiveness, the State should open the sector to competition and gradually relax its grip on the oil market. Protection will only mean that the industry will lose in the near future.*
>
> *-China Daily, December 5, 2000.*[52]

As global energy prices continue to spiral upwards, an opening finally appears to be on the horizon with respect to China's oil sector. The country's central authorities have long maintained a tight grip on its oil industry, particularly the mid-stream and downstream sectors such as import, refining, and distribution.[53] Energy is naturally viewed by

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52. Liu Ming, *Oil Industry Needs Reform for WTO Entry,* CHINA DAILY, Dec. 5, 2000, *available at* http://english.peopledaily.com.cn/english/200012/05/eng20001205_56947.html.

53. Oil exploration and extraction licenses in China are held by only four state-owned conglomerates through which government control over upstream oil is manifested.

Chinese officials as an important issue of national security. Of equal importance, Beijing perceives the price of oil for domestic end-users as a potential threat to the country's social harmony. In China, domestic stability rates high on the government's list of concerns. Such worries are only heightened by the normal strains of expansion as China navigates its way through one of history's most dramatic economic growth spurts.

The increasing international price of oil and growing domestic demand appear now to be turning the tide in China towards a relaxation of import, refining, and pricing restrictions. After all, while price fluctuations are a concern, considerable domestic oil shortages could pose even more of a threat to stability. With the fast changing global economy, the scales are now beginning to tip away from protectionism and towards an encouragement of more private enterprise, foreign investment, and oil imports. Those investors ready to take advantage of the rapidly changing environment may gain a leader's edge in what is likely to be one of the globe's most important energy markets for decades to come.

This paper aims to explain the legal environment in which oil, its import as both refined and crude oil, and its subsequent refining and pricing is managed in China. After familiarizing the reader with key government players, the current legal structure, and how Beijing protects its oil industry, the article will describe the recent movements towards liberalization and point to further indications of fast coming change.

I. KEY AUTHORITIES IN THE OIL INDUSTRY

China's oil industry is closely tied to several key government ministries, primarily the Ministry of Commerce ("MOFCOM") and the National Development and Reform Commission ("NDRC"), both powerful ministries operating directly under the country's central administrative body, the State Council. Historically, MOFCOM and the NDRC have often competed for control in various industry sectors. The same is true for oil. Other authorities like the State Administration of Industry and Commerce, the Ministry of Land Resources, and the Customs Bureau also influence the oil industry. This influence can occur at stages such as the establishment of an oil business, extraction and refining of crude oil, and at the point of import/export or distribution of refined oil products. By and large though, administrative control over China's oil sector is left in the hands of the NDRC and MOFCOM.

MOFCOM exercises sector influence through various functions, including controls over imports, exports, and foreign investment. MOFCOM enjoys the power to grant import/export quotas and licenses,

including those in relation to the import of crude and refined oil by non-state-owned enterprises.[54] The ministry is also involved in the approval of any enterprises engaging in the crude oil business (i.e., distribution and warehousing of crude oil or the wholesaling and warehousing businesses for refined oil products).[55] Along with its local counterparts, MOFCOM further possesses the authority to approve the establishment of foreign invested enterprises ("FIEs") and to delegate its authority to provincial counterparts according to the related total investment amounts of an FIE. Moreover, MOFCOM approves establishment of FIEs by acquisitions in cases where the post-acquisition target will engage in the distribution of crude or refined oil. Finally, enterprises engaging in international trade, whether domestic or foreign-invested, must be recorded and filed with central MOFCOM (or, where central MOFCOM has legally delegated such power, with its local counterparts).

The NDRC is the macroeconomic central planning body under the State Council, and it maintains a strong influence over the oil sector as well. The NDRC and its local counterparts are a key authority supervising fixed asset projects in China. This supervision extends over projects such as the development of refinery facilities or adjustment of production capacities. Major fixed asset development or expansion/refurbishment projects for refineries and major oil operations must accordingly be approved by the NDRC or one of its local counterparts.

The NDRC also exercises oil sector influence through its power to oversee certain prices regulated by the state. For instance, refined oil product prices, particularly gasoline and diesel, are closely controlled by the NDRC, which publishes benchmark retail prices for each province in China. The benchmark prices are calculated through a formula that uses weighted average prices for gasoline and diesel in Singapore, Rotterdam, and New York. The NDRC constrains final retail prices to within an 8% margin of the benchmark prices in accordance with its pre-determined formulas. Such final retail price values are then used to determine wholesale refined oil prices. The NDRC requires that wholesale refined oil products be sold at the retail price less a stipulated profit margin. Such margin is between 5.5% and 7.0% for privately-owned wholesalers and no less than 4.5% for gas stations, which operate beyond the control of major state-owned enterprises.

54. *See* Quota & License Admin. Bureau, Ministry of Commerce of The P.R.C., http://www.licence.org.cn (detailing China's quota and license regime) (last visited Sept. 17, 2008).

55. The provincial level counterparts of MOFCOM possess the authority to issue a certificate for retailing of oil products to domestically funded enterprises.

II. CURRENT OIL SECTOR LEGAL FRAMEWORK AND THE DUOPOLY ALLOCATION SCHEME

Neither MOFCOM, nor the NDRC, nor the Chinese government in general has effectively loosened heavy state regulation of and interference in the oil industry. Despite Beijing's 2001 World Trade Organization ("WTO") accession commitments to open up China's oil industry, the government continues to pull numerous policy levers to maintain a tight grip on the sector. A prime tool for government management is China's allocation of monopoly powers to key state-owned enterprises through which distribution of crude and refined oil and oil products are tightly controlled. Crude oil, whether produced domestically or imported from abroad, must be centrally allocated by the state according to two State Council circulars, the *Circular on Cleaning up and Rectification of Small Refineries and Regulation of the Distribution Order of Crude and Refined Oil Product Markets* and the *Circular on Further Rectification and Regulation of the Refined Oil Product Market,* promulgated by the State Council on May 6, 1999, and August 31, 2001, respectively (the Two Rectification Regulations). In practice, this means that crude oil, including imported crude oil, is required to be sold to one of only two state-owned enterprises: either to PetroChina or to the Sinopec Group (the PetroChina/Sinopec Duopoly). Both state-owned enterprises are themselves major producers of crude oil and are thus competitors with those enterprises forced to sell their supplies to the PetroChina/Sinopec Duopoly.

The crude oil allocation scheme significantly shackles the business activities of local and private Chinese refining companies. Such refineries can rely only on the PetroChina/Sinopec Duopoly for certain amounts of crude oil as allocated by the state, with such amounts strictly limited. With restrictions on the ability of local and private oil refineries to gear up when demand increases, long-term business planning on their part is difficult at best. The end result is a major disincentive for local refineries to invest in refurbishment, expansion, and, generally speaking, their own long term futures.

Wholesale of refined oil (including gasoline, kerosene, and diesel) is also exclusively operated through the PetroChina/Sinopec Duopoly under the Two Rectification Regulations. Although from a legal perspective China has been gradually opening its wholesale refined oil market (as further described below), refined oil products produced by local Chinese refineries, except those produced by the lucky few with a

wholesale license,[56] must be supplied to the PetroChina/Sinopec Duopoly for centralized wholesale. Consequently, most privately owned wholesalers of refined oil products must compete with retailers (i.e., petrol stations) in purchasing oil products from the PetroChina/Sinopec Duopoly above their small, allocated amounts. Limited sourcing channels make local and privately-owned wholesalers heavily dependent on the PetroChina/Sinopec Duopoly. Again, the situation creates uncertainty and deters long-term investment that could increase sector efficiency and, in turn, lead to a much-needed boost to domestic supplies.

III. IMPORT OF CRUDE AND REFINED OIL

With the aim of enhancing supplies, Chinese authorities have somewhat relaxed rigid government controls over the import of crude and refined oil. According to the *Provisional Measures on Regulation of State-Operated Import Trade of Crude Oil, Refined Oil, and Fertilizer* (the "Import Measures"), promulgated on July 18, 2002, trading of crude and refined oil is subject to the control of the state monopoly. Under the Import Measures, importation by state-operated monopolies is subject to quota restrictions and a licensing system under the administration of MOFCOM. As of January 1, 2004, though, China has eliminated import quotas for state-operated importers of both crude oil and refined oil products.[57] MOFCOM licensing requirements, however, continue to remain in place.

Even with the 2004 liberalization, the PetroChina/Sinopec Duopoly's grip over the crude oil market persists. Currently there appear to be only four or five state-owned enterprises licensed by MOFCOM to import and export crude oil as well as refined oil products (e.g., gasoline, diesel, kerosene, naphtha, and wax oil).[58] Two of these state-owned enterprises are reportedly closely connected with the PetroChina/Sinopec Duopoly while two more are PetroChina and Sinopec themselves. Accordingly, the PetroChina/Sinopec Duopoly is able to control the vast bulk of imported crude oil as well as a considerable share of imported refined oil products. Signs of hope do still exist, though, for more licensed enterprises. Unverified reports indicate that a new entity, CNOOC-Sinopec United International Trading Co., Ltd., became the fifth state-

56. Only a small number of enterprises have been so licensed by MOFCOM. Relevant procedures are available at http://oilsyggs.mofcom.gov.cn/gjxkgg/1/cateinfo.html (last visited Sept. 17, 2008).

57. P.R.C. MINISTRY OF COMMERCE, AUTOMATIC LICENSE PROCEDURES ON THE IMPORT OF REFINED OIL FOR STATE TRADING, CIRCULAR NO. 2003 [67], (2004) (2004年成品油国营贸易进口自动许可程序).

58. *See* http://wms.mofcom.gov.cn/static/column/zcfb/e/v.html/1 (last visited Sept. 17, 2008) (listing qualified state-owned importers of fuel oil).

owned enterprise qualified to import crude oil.[59] As the name suggests, however, this fifth importer is a Sinopec joint venture, the qualification of which can only serve to minimally dilute the PetroChina/Sinopec Duopoly at best.

In addition to state-operated importers, non-state operators may also technically import crude oil, though in practice this is quite difficult. The first major obstacle is to register successfully with MOFCOM as a non-state-operated importer of crude, refined oil, or both. Registration requirements are stringent.[60] For example, oil imports require wharf and oil tanks with capacities of 50,000 tons and 200,000 cubic meters for crude oil—a difficult criterion to meet for private or local enterprises, especially those in their early stages of operations. Initial reports indicate that, as of late October 2007, only twenty-two non-state-operated importers of crude oil successfully filed with MOFCOM or its predecessor, the Ministry of Foreign Technology and Economic Cooperation.

Once registered with MOFCOM, the second obstacle to becoming a non-state-operated oil importer is the application for allocation of the right to import oil from the national annual quota for non-state-operated importers. A successful application for a share of the national quota, along with MOFCOM registration, is required before MOFCOM will grant an import license to a non-state-operated importer. Without this license, the China Customs Bureau prohibits crude oil import. Pursuant to the *2008 Quota of Non-State-Operated Import of Crude and Refined Oil*, *Its Distribution Basis, and Application Procedures*[61] (the 2008 Distribution Plan), promulgated by MOFCOM on October 22, 2007, three types of enterprises are eligible to apply for a share: (1) traders of oil products meeting specific requirements (e.g., again, oil import wharf and oil tank, with capacities of 50,000 tons and 200,000 cubic meters for crude oil, or capacities of 10,000 tons and 50,000 cubic meters for refined oil), (2) small traders located near the nation's border areas with an import history over the past three years, and (3) legally incorporated FIEs with independent import histories.

The distribution plan for 2009 helps little in loosening the stringent qualification requirements for non-state-operated oil importers wishing to receive a share of the refined oil import quota. MOFCOM's *2009 Quota of Non-State-Operated Import of Refined Oil*, *Application Requirements, Its Distribution Basis, and Application Procedures*[62] (the 2009 Distribution Plan) of August 23, 2008, does lighten the burden of

59. In Mandarin: 中海油中石化联合国际贸易有限责任公司.

60. *See generally* http://wms.mofcom.gov.cn/aaritcle/zcfb/b/200208/20020800037127.html &16 5236240=3486123669 (last visited Sept. 17, 2008) (listing registration requirements).

61. In Chinese: 2008年原油、成品油非国营贸易进口允许量、分配依据、申请程序..

62. In Chinese: 2009年成品油非国营贸易企业进口允许量申领条件、分配依据和申请程序.

some requirements, but it simultaneously makes others more arduous. For instance, the 2009 Distribution Plan removes the requirement that an applicant's reserve of refined oil not be lower than 15% of its business volume. However, it simultaneously doubles from the 2008 Distribution Plan the bank credit value required (from 10 million USD to 20 million USD).

The 2009 Distribution Plan does little to add to the amount of oil allocable to non-state-operated importers. Crude oil national annual quotas for non-state trading were 14.5, 16.68, and 19.15 million tons in 2006, 2007, and 2008. These numbers comply with China's WTO accession commitment to increase the annual quota at an annual rate of 15%. Similarly, the refined oil national annual quotas for non-state trading were 10.65, 9.26, and 8.05 million tons in 2006, 2007, and 2008, with such numbers also in line with China's WTO commitment. However, the 2009 annual quota of refined oil under the 2009 Distribution Plan is 11.25 million tons, falling short of the WTO 15% commitment.[63]

Even with numerous barriers, the small number of approved non-state-operated importers is beginning to grow. MOFCOM has published in nine batches the names of more than twenty registered non-state-operated importers of crude oil and more than fifty non-state-operated enterprises registered for import of refined oil products as of late October 2007.[64] One must, however, note that at least some of these approved non-state-operated importers are closely linked with existing state-owned enterprises.

One major development in 2008 is that MOFCOM seems to have merged the registration requirement of a non-state-operated importer with the application for a share of the national quota, at least for the import of refined oil. The 2009 Distribution Plan provides that traders who meet the qualification for obtaining and do obtain a share of the 2009 quota for import of refined oil will automatically be registered as a non-state-operated importer. It remains to be seen whether this means that MOFCOM is eliminating the separate registration requirement for an enterprise to become a non-state-operated importer of refined oil. In any case, it is foreseeable that MOFCOM could soon introduce similar measures involving the import of crude oil as well.

63. *See generally* http://www.mofcom.gov.cn/static/column/b/c.html/1 (last visited Sept. 17, 2008) (providing additional information on MOFCOM regulations).

64. *See* Quota & License Admin. Bureau, Ministry of Commerce of The P.R.C., http://www.licence.org.cn/Web/zcfg/jk/327.htm (last visited Sept. 17, 2008).

IV. EXPORT OF CRUDE AND REFINED OIL

Not surprisingly given China's soaring demand for oil products, a de facto prohibition exists on the export of Chinese oil, and thus we touch on the issue here only briefly. The export of crude and refined oil is reserved for state trading and subject to an export quota licensing system in China. Enterprises that wish to export oil must obtain export licenses in accordance with the *2008 List of Goods Subject to Export Licensing Controls,* jointly issued by the Customs Bureau and MOFCOM. While reportedly there are only three state-owned exporters of crude and refined oil, it is unclear how difficult it is to be registered as a qualified exporter. Relevant detailed procedures remain unavailable to the public, and MOFCOM issues no list of such importers publicly. Finally, if qualified, registered exporters wishing to obtain a license must bid for their share of China's export quota. An export license is issued by MOFCOM to successful bidders.

V. LATEST REGULATIONS AND POLICIES

New MOFCOM regulations promulgated last year signal an important shift in China's oil sector policy away from past hostility to foreign and private investment. MOFCOM issued *Measures for the Administration of the Refined Oil Market*[65] and *Measures for the Administration of the Crude Oil Market*,[66] both effective as of January 1, 2007 (the "New Measures"). These New Measures were promulgated due to China's WTO accession commitment to open up its wholesale of crude and refined oil to foreign investors, and they reportedly aim to sever the crude oil centralized allocation system's hold over the wholesale of crude and refined oil. Domestic enterprises as well as FIEs may now legally compete with the PetroChina/Sinopec Duopoly in the wholesale market of China's oil industry. Regarding crude oil, the New Measures legally open up the sale and warehousing markets, covering crude oil extracted from within China's territory as well as that imported from abroad. Existing operation permits are now subject simply to annual inspection, rather than arduous and unpredictable license renewal procedures.

Enterprises have been quick to take advantage of the opening. By late July 2008, MOFCOM had already approved at least nineteen companies (including the PetroChina/Sinopec Duopoly) or branch companies as qualified crude oil sellers and nine as qualified crude oil warehousing

65. In Chinese: 原油市场管理办法.
66. In Chinese: 成品油市场管理办法.

operators. At least five of these nineteen are qualified for both warehousing and selling crude oil.[67]

Even with recent changes, it remains unclear whether the New Measures effectively scrap the centralized allocation of crude oil. Still unknown is whether all crude oil, particularly imported crude oil, must in practice still be sold to the PetroChina/Sinopec Duopoly. If so, then the aforesaid qualified crude oil sellers need to procure crude oil from the PetroChina/Sinopec Duopoly. If an opening is occurring for the new qualified enterprises, though, the loosened grip of the PetroChina/Sinopec Duopoly will provide further impetus for yet more sector reform in the coming months.

Regarding refined oil products, the wholesale and retail sale as well as warehousing is now legally opened up to domestic and foreign investors alike. Such investors must obtain wholesale and warehousing qualifications from MOFCOM. Central MOFCOM has delegated to its provincial level counterparts the power to approve the establishment and subsequent annual inspection of retail businesses, including those in the oil sector. With the powers granted it under the New Measures, reports indicate that MOFCOM approved at least twenty wholesalers and eleven warehousing enterprises of refined oil products between July and November 2007 alone. One must also note, though, that MOFCOM denied many applications during the same period. Finally, under the New Measures, oil products other than gasoline, kerosene, and diesel are no longer subject to a qualification approval.

Notwithstanding the recent market opening, centralized wholesale of oil products by the PetroChina/Sinopec Duopoly is far from gone. Pricing remains a bottleneck for wholesalers and retailers because wholesale prices of the PetroChina/Sinopec Duopoly are pegged to the retail prices, which are in turn closely controlled by the government. Moreover, a 2008 circular jointly promulgated by MOFCOM and the NDRC dictates that local refineries in China, except those lucky few with wholesale qualifications, must sell their refined oil products to the PetroChina/Sinopec Duopoly for centralized wholesale.[68] Thus, for most privately owned wholesalers, the procurement channel obstacle to long-term business planning continues to remain in place.

VI. SIGNS OF COMING CHANGE AND REFORM

Despite the current tight grip of government over China's oil industry, the sector appears on the verge of a breakthrough. Reports have

67. Judging from names, a majority of the approved enterprises are affiliated with the PetroChina/Sinopec Duopoly. *See supra* note 58.

68. In Chinese: 国家发展改革委、商务部关于民营成品油企业经营有关问题的通知.

surfaced that the NDRC is in the process of drafting new favorable policies to support private enterprises. During interviews with the press, high-level NDRC officials admitted to the worsening tension created by the difference between low state-imposed domestic oil prices and the skyrocketing cost of imported crude and refined oil and oil products. NDRC officials also acknowledge shortages of oil supplies caused by the low state-controlled domestic price of oil faced by local refineries. Against such a backdrop, the NDRC has instituted stop-gap measures by increasing refined oil prices in hopes of relieving both local Chinese refineries' difficulties as well as long queues in front of Chinese pump stations. Nevertheless, there appears to be an understanding on the part of Chinese officials that such first steps are no substitute for long-term reforms.

Signs point to a coming relaxation of the regulatory regime governing the wholesale of crude oil. The NDRC is reportedly considering a reform that will allow private enterprises to trade imported crude oil freely on the domestic oil market.[69] Such a policy would remove a key cornerstone in the current requirement that all imported oil must be sold either to Sinopec or PetroChina for onward sale to refineries. Introducing the private sector into the trading mix should appreciably impact the efficiency of domestic crude oil supplies across China.

The government is also looking at allowing local refineries to freely purchase crude oil and directly sell oil products in China, a policy that would yet further deteriorate the PetroChina/Sinopec Duopoly system. The current regime, under which local refineries may only purchase from the PetroChina/Sinopec Duopoly in accordance with an allotted quota, has been a major obstacle to increasing output. The NDRC is reportedly close to a new policy that would allow local private and state-owned refineries to freely source crude oil and, perhaps more importantly, permit them to process and directly sell a wide variety of oil products on the domestic market.[70] If promulgated, such a new policy is likely to reduce extensively strain on soaring domestic demand through augmented sector efficiency.

69. Li Zhu, *Unchained by Two Ministries, Private Crude Oil Closer to Free Trading*, CHINA BUS. J., Nov. 26, 2007 (朱力, 两部委解套 "民营原油"渐近"自由流通", 中国经营报), *available at* http://www.cb.com.cn/news/ShowNews.aspx?newsId=13768.

70. Weiyong Zhi, "Striving to Break the Sourcing Bottleneck of Private Refineries, NDRC Secretively Heading to Shandong Province for Research", *21st Century Business Herald,* Oct. 19, 2007 (支维墉, 求解民营炼厂油源瓶颈 发改委悄赴山东调研, 21世纪经济报道), *available at* http://www.21cbh.com/Content.asp?NewsId=18280 (last visited Sept. 17, 2008).

VII. FINAL THOUGHTS

The oil sector as currently regulated in China reflects a tension between two competing objectives: the hope of holding end-user prices down on the one hand and the desire to keep product flowing on the other. Both are vital for Beijing's dual-pronged goal of strengthening national security and maintaining domestic stability. Until 1993, China was a net exporter of oil.[71] As its reliance on imports since then has grown, so have internal pressures for a shift away from lower prices and a move towards encouraging sufficient domestic supplies.

As the pendulum swings towards a pro-supply standpoint, new initiatives are appearing aimed at encouraging private and foreign investment. Many in China perceive private investment as a way to alleviate the burden of low oil supplies. Adding market players will boost competition and that should lead to higher overall efficiency in the sector. As the opening for private investment naturally grows, so do opportunities for key foreign investors. Foreign investment can positively impact the oil market by introducing new technologies and methodology that will help China get the most out of its oil supplies.

The next decade promises to bring new opportunities for private companies and foreign investors wishing to establish a strong presence in the Chinese oil sector. While non-sensitive areas should be open to one hundred percent foreign investment, it is likely that, as with the automotive industry before it, the oil industry will be opened up gradually, with the most lucrative initial opportunities confined to joint ventures with Chinese partners. In China's auto sector, market entrant leaders such as Volkswagen and General Motors have reaped huge benefits that latecomers came to envy. It appears more and more likely that this pattern will repeat itself within the oil sector as China pulls out all the stops to ensure sufficient energy supplies for its long-term future.

71. Chi Hung Kwan, *Risk of Stagflation Growing with Crude Prices at Record High*, CHINA IN TRANSITION, June 25, 2008.