



A New California Oil Boom? Drilling the Monterey Shale

By Robert Collier

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Next Generation

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Part 1: Distracted by Fracking?

Over the past few years, the United States has found itself in the midst of a major boom in oil and gas production. Rapid expansion in the use of a drilling technique called hydraulic fracturing, or “fracking,” has opened up previously unreachable pockets of oil and gas, and returned the U.S. to its historic position as a major global producer of these fossil fuels.

And it seems the boom may be coming to California. Once a leading producer of oil in the U.S., California’s production has fallen off dramatically over the years as oil fields age and are depleted. But could America’s fracking-fueled oil resurgence breach the oil fields of California, particularly in the relatively untapped Monterey Shale? Could a fracking revolution once again make California a leading producer of domestic oil? And if so, what might this mean for the state’s aggressive clean energy and climate goals?

Given the dramatic examples of North Dakota, Texas and Pennsylvania, where widespread use of fracking has helped oil and gas production soar, it might seem inevitable for California to be the next boom state. The Monterey Shale formation, which runs from north-central through southern California, has billions of barrels of oil locked away in its underground nooks and crannies. Petroleum geologists and engineers, always searching for the next strike, are feverishly seeking the technological fix to unlock those riches.

Politically, it’s the same fight as elsewhere – environmental regulations have been drafted, legislation written and fought over, Hollywood films made, coalitions pro and con organized – all focused on the potential benefits, and threats, of widespread fracking.

A “sleeper” oil field technology?

But in California, at least, the obsession with fracking may be misplaced. In recent months, policymakers have begun to realize that the debate about fracking may be a distraction from the technology that’s

the more likely candidate for tapping the Monterey Shale: A technique, already widely in use in the oil industry, known as “acidizing.”

It’s not widely discussed in publicly, but for some time oil companies [have found](#) acidizing [more effective](#) in the Monterey Shale than fracking.

Acidizing typically involves the injection of high volumes of hydrofluoric acid, a powerful solvent, (abbreviated as “HF”) into the oil well to dissolve rock deep underground and allow oil to flow up through the well. Conventional fracking, in which water and other chemicals are pumped at high pressure to create fissures in the rocks, reportedly does not work well in many parts of the Monterey Shale – a rock formation that is typically folded and shattered by geological fault action, thus making fracking less effective.

A critical tool – but mistakes can be deadly

In the oil patch, hydrofluoric acid can therefore be a critical tool. But HF is also one of the most dangerous of all fluids used in oil production – and indeed in any industrial process. It is used in many oil refineries nationwide to help turn oil into gasoline and other products; while accidents are rare, they can be fatal.

Currently, large amounts of HF (precise volumes are an industry secret) are routinely trucked around California and mixed at oilfields. Critics call it a disaster waiting to happen. There have been [minor HF leaks](#) in other states, though no major catastrophes in the U.S. such as a recent [HF tragedy in Korea](#).

Yet acidizing remains almost totally unregulated. State and federal rules currently being drafted in Sacramento and Washington, DC, make no mention of acidizing. An exception is legislation currently under debate in Sacramento, authored by Sen. Fran Pavley, D-Agoura Hills, who has spearheaded much of the state’s climate laws in recent years.

What is acidizing?

There are two types of acid treatment: matrix acidizing and acid fracturing.

A **matrix acid** job is performed when acid is pumped at low pressure into the oil well and into the texture of the reservoir rocks. The acids dissolve the sediments and mud solids that are inhibiting the permeability of the rock, enlarging the natural pores of the reservoir and stimulating the flow of oil.

Acid fracturing involves pumping acid at moderately high pressure – though considerably lower pressures than conventional fracturing. The acids physically fracture the reservoir rock and dissolve the sediments that are blocking the flow of oil.

Because HF is so successful at dissolving anything it touches, drilling companies add other substances to the mix to prevent the acid from dissolving the oil well's steel casings – which are intended to keep the oil and chemicals from leaching into the surrounding rocks and water table. After the acid job is performed, the used acid and oil well sediments are sucked out in a process called backflush.

A low-volume form of acidizing has long been used nationwide, including in California. This process typically occurs in aging oil wells during the final stages of production, as a means of coaxing out the last dregs of oil before the well is abandoned. In contrast, the tactic now being pioneered in California appears to involve much higher volumes of injected acid as a primary technique for new wells.

In past years, both HF and hydrochloric acid (HCl) were used, depending on the geology. However, the sandstones and silicates that are prevalent in the Monterey Shale [lend themselves especially to HF use.](#)¹

In many cases, HF is created at the oilfield by mixing hydrochloric acid with ammonium fluoride and immediately injecting the mix down the well. Creating the HF on site is accepted as safer than offsite production, as it reduces the risk of transport accidents.

In other cases, however, HF is mixed at a remote location, trucked to the oilfield, mixed there and then pumped downhole.

Whether California regulates acidizing may have national and global implications. Although the state appears to be the first to do major experimentation with high-volume acidizing, the rapid expansion of unconventional oil technologies in shale formations in other states suggests that oil companies might try to export any successful California experiments to other locations.

Industry abuzz, but details are secret

Hydrofluoric acid is typically mixed with water and other chemicals, with HF concentration normally [less than 9 percent](#). However, oil company executives have said they are experimenting in California with higher concentrations and pressures, testing the boundaries of geology, engineering – and safety.

Exactly how high those experimental concentrations and pressures are is a closely held secret. At a May 2013 [industry conference in Bakersfield](#), executives in attendance speculated nervously about what their competitors were doing. Each company was clearly working on its own secret formula, trying to find its own recipe for success.

The buzz among conference attendees was about [Occidental Petroleum](#), which had [demonstrated much success](#) with HF acidizing at its [Elk Hills field](#).

“As you have seen here, companies are experimenting widely with acidizing,” said [Maysam Pournik](#), a geology professor at the University of Oklahoma who spoke at the event.² “Nobody is saying exactly what they are doing, because the Monterey Shale is extremely complex, and companies need to try new methods at the limits.”

Some executives said they believe their competitors were experimenting with HF concentrations as high as 30 percent. But others downplayed such talk.

“If you use that much HF, you will melt your well casings,” said Paul Gagnon, senior vice president of Central Resources, a Denver-based oil firm. “It’s not doable.”³ Left unsaid was the environmental danger – that HF could breach the double or triple steel walls of the well casings and enter the surrounding water table, putting local water supplies at risk.

A recognized human hazard

HF is commonly used in oil refineries, where it serves as a catalyst to produce high-octane gasoline. It is one of the most hazardous industrial chemicals in use, according to the U.S. Centers for Disease Control. HF can cause severe burns to skin and eyes, and can damage lungs in ways that may not be immediately painful or visible. Overexposure causes painful, deep-seated and slow-healing burns and ulcers. If absorbed through the skin in even minute amounts and left untreated, HF may cause death.

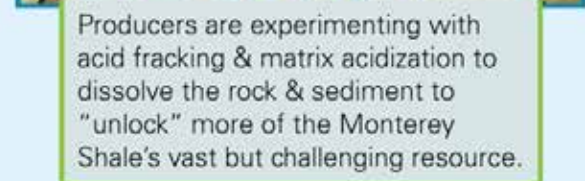
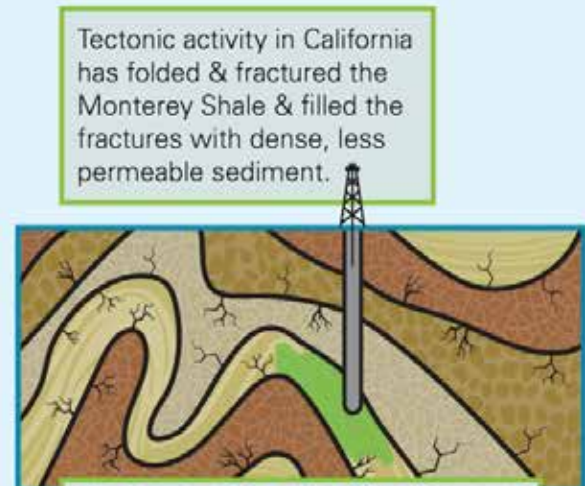
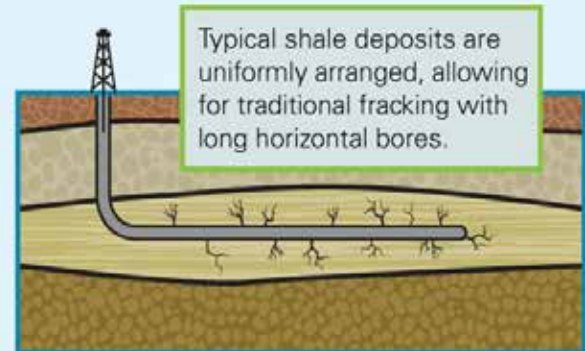
The dangers of HF are compounded by its extreme volatility at relatively low temperatures. If temperatures are cool, HF is a liquid. But at 67.1 degrees F, HF boils into a dense vapor cloud that, if released into the open, does not dissipate, hovers near the ground and can travel great distances – meaning the risks of a spill to nearby population centers are significant.

The National Fire Protection Association system rates hydrofluoric acid in the most dangerous category of hazardous materials. Hydrofluoric acid also is recognized on the Superfund list of Extremely Hazardous Substances. As a powerful corrosive, it dissolves nearly anything – research on matrix acidizing lists “corrosion” as one of the primary challenges.⁴

There appears to be no research or other publicly available information about HF’s use in oil and gas production or its potential effects on groundwater supplies. But the risks are clear.

Monterey Shale Geology

The unique geology of California’s Monterey Shale renders conventional fracking methods less effective.



Source: Steve Hargreaves, CNN Money

Part 2: The Most dangerous chemical you've never heard of

Editor's note: In [part 1](#) of our series on the Monterey Shale, Next Generation researcher Rob Collier outlined the technical challenges of developing the Monterey Shale oil field – and how a technique known as “matrix acidizing,” which uses hydrofluoric acid to dissolve underground rock formations, may be the key to its development. In Part 2 we explore the risks of widespread HF use.

“No industrial process risks more lives from a single accident than does the subject of this report – alkylation using hydrogen fluoride in oil refining. Fifty American refineries use HF alkylation to improve the octane of gasoline. Many are situated in or close to major cities, including Houston, Philadelphia, Salt Lake City and Memphis. In some cases, more than a million residents live in the danger zone of a single refinery. All in all, more than 26 million Americans are at risk.”

So says a [2013 survey of 50 U.S. oil refineries by the United Steelworkers union](#), which represents refinery workers. The survey found that “over a five-year period, the refineries in the study experienced 131 HF releases or near misses and committed hundreds of violations of the OSHA rule regulating highly hazardous operations.”

In July 2009, an explosion blasted the Citgo East oil refinery in Corpus Christi, Texas, critically injuring a worker and sparking a fire that burned for more than two days.

In September 2012, in Gumi, South Korea, about eight tons of HF gas burst from the Hube Global chemical plant. The leak killed five workers and severely injured at least 18 others, including plant employees and emergency personnel. An [estimated 3,000 local villagers](#) required medical treatment.

Because of these well-documented risks, the USW is advocating for refineries to stop using HF and to substitute safer chemicals and processes.

A [joint investigation in 2011](#) by ABC News and the Center for Public Integrity came to an equally chilling conclusion:

At least 16 million Americans, many of them unaware of the threat, live in the potential path of HF if it were to be released in an accident or a terrorist attack, a joint investigation by the Center for Public Integrity and ABC News has found. The government maintains closely controlled reports outlining worst-case scenarios involving highly hazardous chemicals. The Center reviewed reports for the 50 refineries that use HF. The reports describe the most extreme accidents anticipated by the plants' owners. The information is not published and is not easily accessible by the public.

A recent spate of refinery equipment breakdowns, fires and safety violations has heightened concerns. Over the past five years, authorities have cited 32 of the 50 refineries using HF for willful, serious or repeat violations of [rules](#) designed to prevent fires, explosions and chemical releases, according to U.S. Occupational Safety and Health Administration data analyzed by the Center. These “process safety management” standards require companies to conduct inspections, analyze hazards and plan for emergencies.

In all, at those 32 refineries inspectors found more than 1,000 violations, including nearly 600 at the BP refinery in Texas City, Texas, where 15 workers were killed and 180 injured in a 2005 explosion. Although only some of the violations involved HF, they can be an indicator of operational weaknesses, particularly worrisome at refineries using the chemical, industry and government insiders say. Even a fire causing little damage can foreshadow a more serious event, the American Petroleum Institute, the oil industry's main trade association, notes in a 2010 guidance document for its member companies.

Some worst-case scenarios described in company filings with the U.S. Environmental Protection Agency are particularly chilling: An HF release from the BP refinery in Texas City, for example, could total 800,000 pounds, travel 25 miles and put 550,000 people at risk of serious injury, according to BP's own calculations, provided to the EPA.

And a release from the Marathon refinery near Minneapolis could total 110,000 pounds, travel 25 miles and threaten 2.2 million people.

In response to safety concerns, the two California refineries that use HF – Valero in Wilmington and ExxonMobil in Torrance – have adopted a modified form of HF that is less volatile. This new form remains extremely dangerous, as described in a [2010 fact sheet](#) by Honeywell, a leading manufacturer of modified HF, which called its product: “extremely corrosive and destructive to tissue. Causes severe burns. May be fatal if inhaled, absorbed through skin, or swallowed. Specialized medical treatment is required for all exposures.”

Despite all this information about HF use in refineries and other industrial settings, little is known about HF practices in California oilfields, and oil companies are tight-lipped.

Remarkably, California health and safety regulators appear to be unaware that HF is being used. Clyde Trombetta, Cal-OSHA's chief supervisor for both oilfield and refining operations, wrote in a June 14, 2013 email that he didn't know that HF was being used in oilfields. “When it comes to Hydraulic Fracking in California I do not believe the industry uses hydrofluoric acid and hydrochloric acid in its matrix,” he wrote.⁵

Chemical safety experts say that California's pioneering use of HF poses unique challenges. “You have uncounted numbers of trucks moving HF around the state, it's unclear whether the workers are trained in proper safety protocols, whether local first responders are prepared, or whether anyone is prepared for a potentially lethal accident of significant proportions,” said Kim Nibarger, a health and safety specialist for the United Steelworkers. “It seems totally unregulated.”

HF Danger Zone: Los Angeles

While hydrofluoric acid is likely in use in California oil fields, it is already in use in some refineries. A leak in an urban setting could affect thousands of Californians.



Torrance Refinery

Wilmington Refinery

In the worst-case scenario, a leak at these sites could place as many as 360,000 individuals at risk of exposure to HF.

 Potentially Threatened Area

Source: The Center for Public Integrity

A 2008 report by the Center for American Progress, “[Chemical Security 101: What You Don't Have Can't Leak, or Be Blown Up by Terrorists](#),” listed HF as the nation's second most dangerous industrial chemical at risk of being used in terrorist attacks. The report highlighted HF's prevalence in oil refineries, but did not mention its use in oilfield production – perhaps because there had been almost no attention to date to the Monterey Shale.

The author of that report, Paul Orum, now says that because of the typically low security in oil services trucking and oilfields themselves, HF is a risk. “The consequences of a deliberate HF spill could be catastrophic, depending on the location, and California would be well advise to consider this in its policies,” he said.⁶

A giant regulatory gap

In recent years, as the national debate over fracking became a cause celebre from New York to Hollywood, acidizing remained relatively obscure – and cloaked in relative secrecy. In California and elsewhere, oil companies face no disclosure requirements for acidizing. As a result, there is little information available to the public about when, where or what kinds of acids, what depth, what strength, what volumes, or even whether they are doing it.

There is [no mention of the topic](#) in the U.S. BLM's new draft rule for well stimulation methods, which includes hydraulic fracturing, on federal and Native American lands.

In California, the attention to acidizing came belatedly. After years of being a backwater in the fight over fracking, California entered the fray in earnest in early 2013. A flurry of [media coverage](#) about fracking's potential in the Monterey Shale prompted environmental groups and legislators to jump on the national bandwagon. It was all fracking, all the time. Acidizing, however, was unmentioned.

The California Division of Oil, Gas, and Geothermal Resources (DOGGR) finally agreed to write regulations to govern the fracking process. Its [initial draft](#), released in December 2012, made no mention of acidizing, but DOGGR's chief deputy director recently [indicated](#) the practice might be included in a forthcoming draft. Industry officials, who have supported DOGGR's initial version, [suggested they would fight](#) to stop any inclusion of acidizing.

A new draft of regulations is expected to be released in August 2013, with final approval, after additional hearings, likely in mid-2014.

Gearing up for regulatory battle

The door was cracked open in April, when the South Coast Air Quality Management District [issued new regulations](#) that would mandate disclosure of "the names and quantities of chemicals, non-trade and trade secret, and other process information within 60 after days after completion of well activities." The measure did not impose any limits on acidizing, but it marked the first time anywhere in the United States that oil companies were even required to disclose acidizing.

But soon after, acidizing came into the sphere of interest among activists and legislators. In June, Senator Fran Pavley scheduled a [hearing](#) in the state Senate to investigate the use of acidizing. She invited Chevron, Occidental and Venoco and the oilfield services company Halliburton to testify at the hearing, asking them to provide information on "the type and number of oil stimulation treatments, including acid-based treatments" that the companies use and plan to use in California.

All three companies declined, deferring to two industry associations to address the panel's questions. "We use acid because it's effective," [testified Paul Deiro](#) of the Western States Petroleum Association. "I'm unaware of any disasters related to this." He urged the legislators to avoid "unnecessary" regulation of acidizing.⁷

Faced with stonewalling, Pavley promptly amended her bill – which until then had been focused exclusively on fracking – to add a requirement requiring full disclosure of acidizing activities. She also added acidizing to the bill's authorization for the state to commission an independent, peer-reviewed study of the environmental health effects of well drilling techniques.

This study, to be completed by Jan. 1, 2015, would fill in critical gaps in the nation's knowledge of fracking's impacts, which have not been widely studied; it would also be the only study to date about the potential impacts of acidizing. The study's findings could prove to be a major boon to other states and nations that are seeking a responsible approach to the rapid expansion of fracking and acidizing.

Whatever the study's conclusions, it could give the general public and policymakers alike the information they need to make informed decisions about a formerly obscure drilling technique that is now entering the limelight.

Part 3: The Climate conundrum

With elected officials and energy experts buzzing about the potential for a major boom in oil production from California's Monterey Shale, little attention has been given to the risk that a new oil boom could undermine the state's plans for addressing climate change. If the as-yet unrealized surge in Central and Southern California's Monterey Shale were to materialize, it could boost the state's climate pollution, just as the state grabs the mantle as a global leader in reducing greenhouse gas emissions.

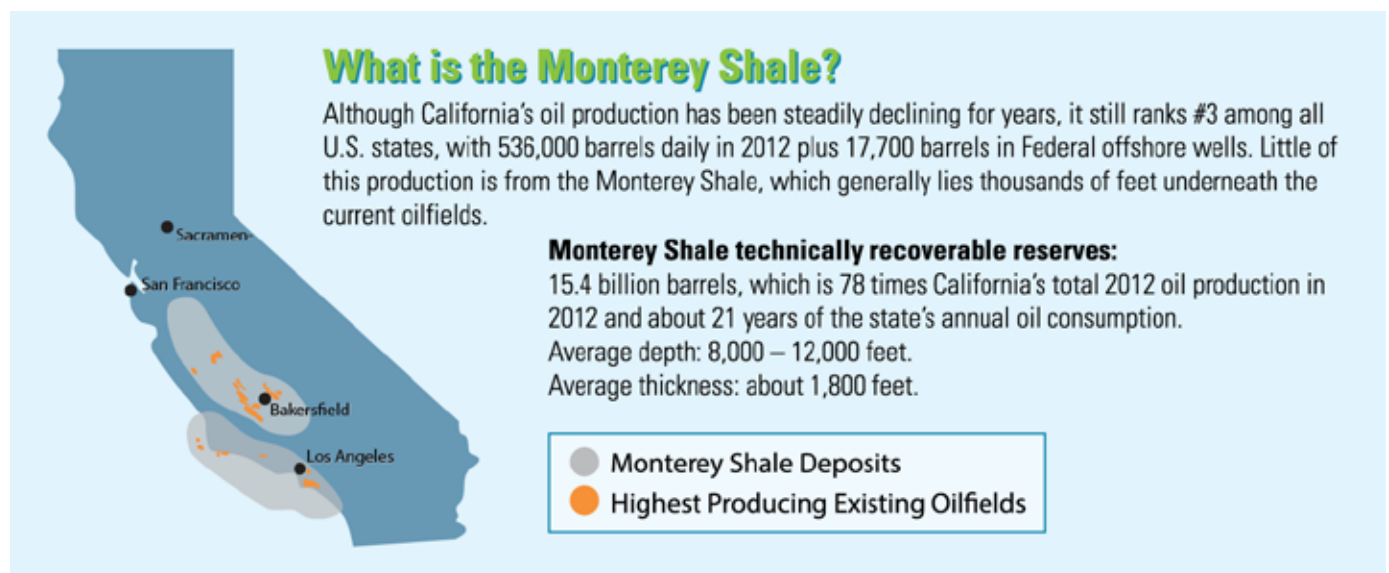
Public discussions of the climate impact of an oil boom have been limited by lack of information about potential rates of growth in oil production or greenhouse gas emissions. The key questions revolve around scale and speed: How much of the oil would be produced, and over what time period? Would oil production grow at the same speed as shale oil booms in North Dakota and Texas? Or would technical difficulties slow any increase to a

modest, manageable crawl? Or, perhaps as likely as any other scenario, would the oil mirage turn into just another over-hyped, Western bust?

Predicting a boom: At what speed?

The mother lode of California's potential oil bonanza is expected to be the Monterey Shale, a deep layer of rocks stretching from the southern edges of the San Francisco Bay Area all the way to Orange County. Geologists believe the Monterey Shale may hold 15.4 billion barrels of technically recoverable oil, or [more than twice the shale oil deposits of all other states combined](#).

Around the United States, new drilling techniques have upended conventional wisdom, causing unprecedented surges in production from oil and gas reserves that had previously been inaccessible.



This rapid shift in potential – from reserves that were believed to be off limits – has yet to fully arrive in California, where the geological complexity of the Monterey Shale has so far stymied oil companies’ attempts to unlock its secrets. Petroleum engineers are feverishly trying new drilling techniques that they hope will solve these riddles. If and when there is a “breakthrough” moment, the pace of development could take off like a rocket.

Many existing factors could help accelerate Monterey Shale production growth:

- **Size.** The Monterey’s reserves dwarf those of other, more established U.S. shale plays, with estimates showing twice the amount of oil of North Dakota’s [Bakken field](#) and Texas’s [Eagle Ford](#) field combined.
- **Location.** The Monterey’s deposits are located in a densely populated state with a huge market for oil conveniently located a short distance away. In some cases, such as the Los Angeles oil basin, the market is literally overhead.
- **Property holdings.** Because the Monterey generally lies directly underneath the state’s existing oilfields, oil companies could take advantage of their existing properties and facilities to speed development.
- **Transport.** According to the California Energy Commission, the state’s pipelines and rail networks have enough capacity to absorb at least a doubling of the state’s total oil production, and probably much more.⁸
- **Refinery capacity.** In-state oil production only provides about one-quarter of the [state’s oil refinery consumption](#) of about 2 million barrels per day; because of the U.S. [near-total ban on crude exports](#), California could probably absorb a major boost of oil output with no need to seek expansion of existing refineries.

All these factors contrast markedly from conditions in the Alberta tar sands, where huge amounts of crude are thousands of miles from any market – and could wind up stranded unless the Keystone XL or other export pipelines are built.

Many economists who study the oil industry say that if the Monterey’s technical problems are resolved, market and political factors would lead oil companies to try to maximize their output, just as they have done in North Dakota and Texas.

“The effect of Monterey Shale on the world oil price will be minimal”
—Severin Borestein

“The economic stakes make the development of Monterey energy inevitable,” said David Roland-Holst, professor of economics at UC Berkeley. “Institutional constraints, including refinery regulation and both de jure and de facto environmental oversight, will be tempered by two forces: The first is the state’s fiscal situation, for which these resources will be seen by some as a panacea,” he said. “In other words, public tax revenues from oil-related economic activity are truly additional and would represent a very big bag of political candy.”

Although California is the only major oil producing state that does not charge a severance tax, the oil industry gains considerable political clout through its claims that it generates billions of dollars in indirect tax revenue. A coming report by Next Generation will take a close look at the veracity of these claims.

Roland-Holst said a Monterey boom is unlikely to be slowed significantly by political concerns: “The second factor moderating environmental concerns/objections could be the history of fracking in California. A variety of these methods have already been in use here for over 20 years, without documentation of significant adverse effects,” he said.⁹

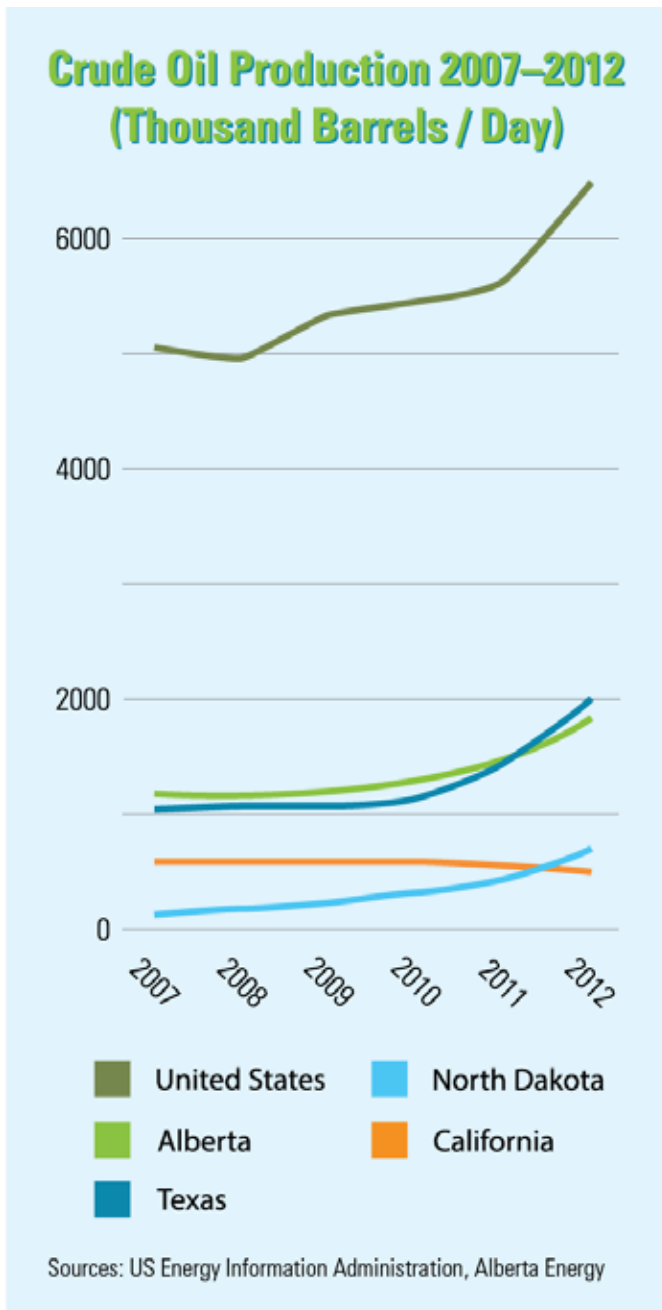
Other experts noted that California’s oil prices are thoroughly integrated with the world market, so with the international Brent benchmark at roughly \$110 per barrel and futures prices predicting no significant decrease, the market’s appetites will be powerful.

“No firm will make a field development decision based on that field’s impact on the global market, because no single field is large enough for it to matter on its own,” said Kenneth Medlock, senior director of the Center for Energy Studies at Rice University.¹⁰ A similar view came from Severin Boreinstein, co-director of the Energy Institute at the Haas School of Business at UC Berkeley: “The effect of Monterey shale on the world oil price will be minimal so that won’t be a constraint on rampup. I think rampup constraints will be more technical than economic.”¹¹

Production scenarios: an informed guessing game

Based on recent history, a wide range of scenarios is possible:

- California’s production from conventional oil wells [has slid gradually over the years](#), from about 1.1 million barrels per day at its high in 1985 to 536,000 barrels in 2012. From 2007-2012, the rate of decline was 3 percent annually. This decline stopped in 2012 and output is expected to remain flat in the next two or three years, as high oil prices cause companies to eke out extra production in their decades-old fields. The Monterey provides little of California’s current production.
- After years of decline, U.S. [total oil production is now rising rapidly](#), fueled by sudden increases in North Dakota and Texas. Nationwide oil production rose 5.1 percent annually from 2007-2012 and is [projected to increase by 13 percent annually during 2012-2014](#), according to the Energy Information Administration.
- Alberta’s tar sands reserves are far larger than those of the Monterey, with an estimated 168 billion barrels recoverable. But [tar sands production](#) has grown at a slower pace than shale plays south of the border, rising from 1.1 million barrels per day in 2007 to 1.9 million in 2012, or 11 percent annually.
- [Texas’ oil production](#) has doubled since 2007, to about 2.3 million barrels per day, for an increase of 14 percent annually.
- [North Dakota’s daily oil output](#) has soared by more than 500 percent since 2007, to about 750,000 barrels per day in early 2013, or 40 percent annually.



Academic and industry experts say they are unsure what sort of growth projections could be realistic for the Monterey.

Richard Behl, professor of Geology at California State University at Long Beach, points out that the Monterey Shale is still relatively unexplored, and its extremely complex geological structure presents challenges that have never been solved at other oilfields.¹² Unlike the state's traditional oilfields, where companies focus on the convex folds known as "anticlines" in which oil has collected over the millennia, the Monterey's oil is believed to be more dispersed underground.

"Assuming exponential rates of growth in the monterey seems very risky to me"
—Robert Garrison

"We don't know a lot about the deeper structures of existing oilfields. No one ever drilled into those, and it's expensive to drill deep," Behl said. "Everyone has been drilling into anticlinal folds and traps, and that's where production has been for the past century, so the oil companies know that well. But the Monterey is different."

Behl, who has extensively studied the Monterey Shale and is widely viewed as the state's chief academic expert on the subject, admitted he was of two minds about its potential.

Asked whether California could ramp up at the speed of North Dakota, he said that scenario was "too speculative." But he also volunteered that once oil company geologists figure out the Monterey's secrets, growth could be rapid.

"California could ramp up just as fast as North Dakota or Texas," he said. "It's possible. But there are too many variables to know for sure."

"A lot of hype"

Other experts are more skeptical of California's ability to rapidly ramp up shale oil production. "There's a lot of hype in this issue," said Robert Garrison, a professor emeritus of geology at UC Santa Cruz. "Assuming exponential rates of growth in the Monterey seems very risky to me, and not necessarily substantiated by much."¹³

Oil companies and their supporters promise explosive job growth from a Monterey oil boom, citing a bullish, oil industry-funded [2013 report by the University of Southern California](#). That study predicted even faster rates of growth in California oil production than those of North Dakota. But industry spokespeople now demur when asked about specific production levels. "Gosh, we have no idea about where the production levels could go," said Tupper Hull, vice president of the Western States Petroleum Association. "We're hard at work on solving the technical issues."¹⁴

In sum, the scenarios are varied. What is clear, however, is that any net increase in California oil production would cause a corresponding increase in greenhouse gas emissions. Evaluating those emissions scenarios is the key task for state leaders focused on achieving their aggressive climate goals.

Part 4: Monterey Shale: Twice as polluting as Keystone XL?

As California decision makers ponder how to plan for a potential new oil boom in the Monterey Shale, they are faced with the daunting task of calculating many complex factors – not only a wide range of oil development scenarios, but also the potential increase in fracking and acidizing, the implications for state budgets, possible impacts on in-state consumption and refinery activities, and serious gaps in understanding of the geologic and environmental issues that may arise with a boom.

Much of California's current petroleum output is categorized as heavy or extra-heavy oil, meaning it is more viscous and requires more energy and time to refine into fuel than lighter grades of crude. In many ways, it is similar to the thick "bitumen" petroleum that comprises Alberta's tar sands. Lighter grades, such as those found in Texas and North Dakota, have lower carbon emissions footprints because they require less energy to extract and refine.

All heavy and extra-heavy grades require a variety of energy-intensive methods to liquefy, extract from the ground, and refine into gasoline, diesel and other transportation fuels. As a result, many California oilfields have greenhouse gas emissions per barrel similar to the Alberta tar sands crudes, [according to the California Air Resources Board](#). In 2007, 70 percent of California's active wells produced extra-heavy or heavy crude, and 56 percent of new wells drilled were extra-heavy or heavy.¹⁵

As a rule of thumb, California's inland oilfields tend to have heavier crude, while coastal and offshore oilfields have lighter varieties. For example, the carbon intensity of the state's largest oilfield, Kern County's Midway-Sunset, and its eighth and ninth largest, San Ardo in Monterey County and Coalinga in Fresno County, [are as high or higher](#) than those of the Alberta tar sands. Most oilfields in the San Joaquin Valley are heavy or extra heavy.

Carbon Intensity of Existing Oil Fields



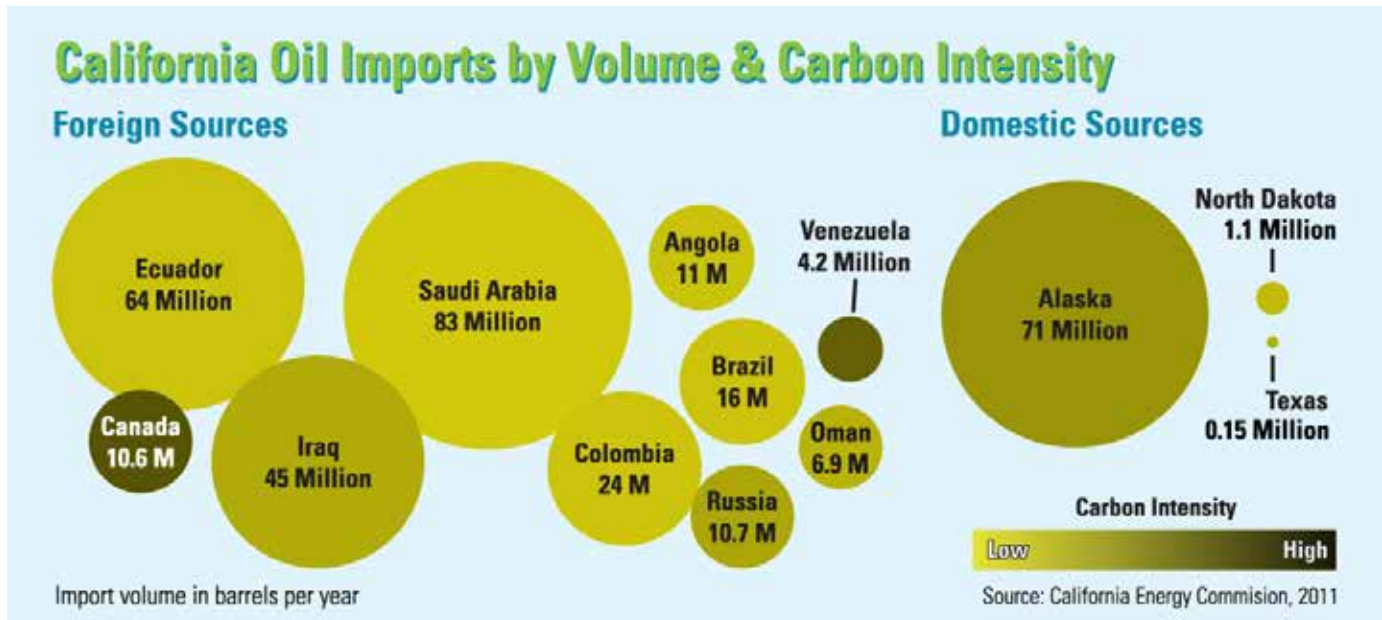
Top Oil Fields Ranked by Carbon Intensity

1 Round Mtn.	8 Belridge, S.	15 Point Pedernales
2 San Ardo	9 Lost Hills	16 Belridge, N.
3 Coalinga	10 Point Arguello	17 Hondo
4 Poso Creek	11 Inglewood	18 Ventura
5 Kern Front	12 Kern River	19 Pescado
6 Midway-Sunset	13 Elk Hills	20 Sacate
7 Cymric	14 Wilmington	

In contrast, the oil along the coast tends to be lighter. Many fields in the Los Angeles Basin, Ventura Basin and offshore Santa Barbara produce cleaner burning, light, sweet grades of crude that are as coveted by refiners as the light, sweet blends from Saudi Arabia and Ecuador, California's two [leading sources of foreign imported oil](#).

Legacy of the 1969 spill

Given the disparity in oil types, worries have arisen that the state's climate policies could cause a paradox – pushing the Monterey Shale's coming oil boom into the lighter, cleaner crudes along the coast, rather than into the dirtier, heavier deposits under the badlands of Kern County.



California's oil lobby has warned that, if strict carbon regulations are applied to California crude oil production and refining, they will be forced to conduct a process known as "shuffling," in which California refiners would export the state's heavy, high-carbon oil to other countries, and then import lighter, lower-carbon oil from abroad. They note that only 39 percent of the crude oil refined in California is produced in the state. The remaining 61 percent comes from Alaska or foreign imports via oil tankers, or from western U.S. states by rail. Under shuffling, oil executives say, California oil would likely be replaced by imported sources of light, sweet oil.

Political realities suggest this will not happen. Oil industry lobbyists have recently backtracked on earlier suggestions that they would shuffle their oil supplies. They now say they will go where the political going is easiest – which means staying away from cities and the coast, where memories of the 1969 Santa Barbara offshore oil spill are still vivid and public opposition to oil drilling is strong.

"I don't really expect that there will be much work in the Monterey outside of the San Joaquin Valley, at least for quite a while," said Tupper Hull of the Western States Petroleum Association.¹⁶ "As you know, Los Angeles and the coast is a very strict regulatory environment. The San Joaquin is where most of the resource is."

What's more, the state's complex climate policies may not allow shuffling. Adam Brandt, an assistant professor of Energy Resources Engineering at Stanford University and the state Air Resources Board's chief expert on the climate impact of transportation fuels, says that the state's cap and trade system, which is now in operation, and the Low Carbon Fuel Standard, which is now under court challenge, prohibit shuffling. All in-state sources of crude are averaged in a single basket for greenhouse gas intensity, with no differentiation between companies' individual sources of in-state supply.

"This issue is confusing, I'll admit," said Brandt. "But despite the real disparity in carbon intensity of California crudes, or because of it, the state has deliberately designed its rules to prevent that kind of shuffling."¹⁷

The upshot of all this is that the dirtiest portions of the Monterey Shale are likely to be developed first, making the overall prospect for an oil boom a distinctly carbon-intensive affair.

Production methods: a primer

Predictions for California's oil industry emissions are also complicated by the lack of clarity about which production methods will be used, and at what depth. Some of these variables could make the Monterey Shale output cleaner than current California crudes, while others would make it dirtier. Here is a summary:

- **Depth.** While oil is found less than 2,000 feet deep in fields like Midway-Sunset, companies must drill to between 6,000 feet and 15,000 feet to tap shale oil in the Monterey. The additional depth requires extra energy for drilling, well completion, pumping and all other activities, all adding up to an approximately 1.3 percent increase in total carbon intensity per 1,000 feet. However, deeper oil tends to be somewhat lighter and less viscous than shallower oil, as explained by Richard Behl, a geologist at CSU Long Beach. "What controls the gravity of oil is what type of organisms were buried there before oil formed whether the oil was collecting in reservoir rocks that over geological times was exposed to bacteria and degraded its composition," Behl said. "A lot of shallower deposits are very heavy, but much of the Monterey Shale deposits are more deeply buried, so it probably will be lighter. It's too speculative to say by how much, however."¹⁸
- **Fracking.** Fracking has long been used in California oil production, with the first occurrence in the Whittier oilfield in 1953. However, oil industry officials say that because of the complex nature of the Monterey Shale, fracking may be ineffective in many areas and other techniques such as acidizing may be more effective. However, no information is available about energy intensity of the fracking process. Stanford's Adam Brandt says he is only now starting the months-long process of crunching that data for the ARB. Because fracking is currently unregulated and no reporting of the practice is required, state regulators do not know what proportion of the state's oil is produced through fracking.
- **Steam injection.** This method – the injection of hot water vapor downhole – is a [common way of melting extra-heavy crude](#) that is too tar-like to be easily extracted through conventional drilling. Steam injection is by far the most energy-intensive and water intensive method used in California oil extraction. In 2007, 23 of the state's 153 oilfields used steam injection, [according to ARB data](#). A similar method is hot water flooding, which injects hot water instead of steam. Steam generation represents 41 percent of the California oil and gas industry's GHG emissions, while combined heat and power (which includes hot water heating and other drilling-related electricity use) causes another 22 percent, [according to the ARB](#).

"When you see high values for carbon intensity at California oilfields, it's almost always due in large part to steam injection or waterflooding," said Brandt.¹⁹ He said the methods for extracting the Monterey Shale's crude will be similar to anyone following the national debate over the Keystone XL pipeline. "You have extra-heavy crude, and the only way to get it out is via a process very similar to the 'in situ' production of the tar sands," he said, referring to the Canadian practice of pumping steam down into the oil-bearing strata and waiting for the heat to melt the tar-like, compacted sands into a liquid that can be pumped up to the surface.

For the most part, Brandt noted, steam injection and hot waterflooding currently are used in relatively shallow depths in California, to a maximum of approximately 5,000 feet. While it is likely these methods will be adapted to the Monterey Shale, there is no guarantee they will be used at a greater rate than currently.

- **Acidizing.** As discussed in Next Generation’s [two-part report about acidizing](#), oil companies operating in California say that many areas of the Monterey Shale do not respond well to fracking and instead give better results through the process of acidizing, which includes matrix acidizing and acid fracking. In these methods, large volumes of hydrofluoric acid are injected into the substrata to dissolve the rock and open up fractures so that the oil can flow. As with fracking, this practice is largely unregulated, so no information is available about what proportion of the state’s oil is extracted via acidizing, and no research has been carried out about the carbon intensity of acidizing.
- **Clean tech.** State regulators have created a system of incentives to support the use of “clean distributed generation technologies” to replace the natural gas that fires the steam flooding process and other oil well activities. These include a complex variety of low-carbon technologies – microturbines, fuel cells, and a thermal oxidizer integrated with a microturbine. One especially promising method is solar thermal enhanced oil recovery, with two test projects currently underway – [Berry Petroleum with GlassPoint Solar in McKittrick, Kern County](#), and [Chevron’s partnership with BrightSource Energy](#) near Coalinga. In both cases, an array of solar concentrating mirrors tracks the sun, captures rays, then shines the concentrated light to heat the water into steam, which is then pumped down into the oil reservoir. This method is estimated to [cut CO2 emissions](#) of oil extraction by up to 80 percent. All these projects are experimental, with no guarantee that they will prove successful or be used widely in the Monterey – or in other shale formations around the country or world.

A USA worth of emissions? Or two Keystones?

There are two ways of comparing greenhouse gas emissions for the California oil industry: A broader scope, known as the “well-to-wheel lifecycle” approach, which adds the cumulative total of emissions from the oil’s production and final consumption, regardless of where the oil is eventually used, over the project’s entire lifetime; and a narrower scope that measures the annual rate of in-state emissions from the “upstream” process of drilling, extracting and transporting the oil but does not measure refining or consumption.

Both yardsticks have their weaknesses. The well-to-wheel lifecycle approach might exaggerate the net carbon impact if Monterey Shale oil simply displaces imported sources of oil, and if it does not increase end-use consumption by the state’s transportation sector. The upstream-only approach does not show the overall impact on global greenhouse gas emissions of an up-or-down decision to develop the oil or instead leave all of it in the ground.

Well to wheel lifecycle approach. According to calculations by Argonne National Laboratory using data from ARB, the lifecycle emissions – extracting, transporting, refining and consuming – of the average barrel of California oil are equivalent to 0.5 metric tons of carbon dioxide.²⁰ As a result, production of the Monterey Shale’s entire 15.4 billion barrels would release 7.7 billion metric tons of carbon dioxide, equivalent to 17 years of [California’s total greenhouse gas emissions at 2010 levels](#), or about one year of total emissions for the United States.

This approach essentially measures the carbon cost of extracting the oil rather than leaving all of it untapped. Of course, there is no guarantee that the Monterey’s 15.4 billion barrels could actually be extracted. Given the current technical difficulties in accessing the oil amid its jumbled formations, there is a real possibility that a significantly lower proportion of that resource will be used. Nor is the speed of this process at all clear – over a few decades, or stretched out over a century? Another difficulty with this approach is that it does not recognize the likelihood that the Monterey’s production would displace imported supplies of crude, making little measurable impact on the in-state emissions of California’s own transportation sector. All these caveats suggest some prudence in drawing conclusions.

Upstream only. It's possible to construct a range of possible emissions scenarios by taking three potential rates of growth for the Monterey Shale, based on output rates in other states from 2007 to 2012 – the North Dakota rate of 40 percent annual increase, the Texas rate of 14 percent, and the nationwide U.S. rate of 5.1 percent. Based on these scenarios, the [California oil and gas industry's annual output of greenhouse gases](#) would rise by the following amounts from approximately 12.5 million metric tons of CO2 equivalent in 2015 (assuming no change from 2011).

“For now, the Monterey Shale remains a mirage waiting to become a reality”

The policy implications of the above scenarios vary wildly. [The state's climate plan](#) mandates that 80 million metric tons must be cut from the state's overall annual emissions by 2020. If the state's oil output were to grow by the U.S. rate, the impact on the climate plan's goals would be moderate – still a step backward, but not unmanageable. If it were to grow by the North Dakota rate, however, the impact would be severe, forcing more drastic cuts in emissions elsewhere.

Another point of comparison is the projected annual rate of emissions from the oil transported by the Keystone XL pipeline, which the U.S. Environmental Protection Agency [has estimated at 27 million metric tons](#). If the California oil industry's output were to grow at the North Dakota rate, its emissions would be twice as large as the Keystone XL emissions.

The above growth scenarios do not include significant increases in refinery emissions.²¹ The state's 18 refineries have [a total capacity of about 2 million barrels per day](#), of which California's current oil production supplies only about one-quarter. Federal law [strictly limits crude oil exports](#) from the

United States to foreign nations; given the lack of any major oil pipelines that could send California crude to other states, it seems likely that most, if not all, Monterey Shale oil will remain in-state and will merely replace supplies of crude that are currently imported.

In addition, California's refining capacity is configured for a wide range of oil viscosity, including heavy imported crude. So a switch to local supplies would have little net effect on refineries' energy use and emissions – leaving no basis to assume any substantial change of the refinery sector's emissions under any of these scenarios.

For now, the Monterey Shale remains a mirage waiting to become reality. The wide gamut of possible scenarios – boom, mini-boom or bust? – means that the jury is still out on the possible climate impact of a net increase in oil production. As with other facets of the national and global debates over climate change, much remains unknown.

But the success of California's landmark climate policies are clearly at stake. Time will tell if the state's leaders will remain as committed to existing climate goals when – and if – the black gold starts flowing from the Monterey Shale.

Part 5: Is California really like North Dakota?

The oil industry has been inflating its projections of jobs that could be created by a potential new California oil boom, according to independent economists who have reviewed the industry's research and who say the state should cast a more skeptical eye on claims of a potential new oil boom in the Monterey Shale.

These economists' view is bolstered by a little-publicized study from a top oil research firm that found little likelihood of a resurgence in oil production in California over the next one to two decades.

Up until now, the runaway growth of shale oil and gas production in North Dakota, Texas and Pennsylvania have led some analysts to predict that California's shale oil deposits, estimated to be the nation's largest, could spawn a gusher of economic growth.

The oil industry has helped promote this vision, predicting millions of new jobs, a statewide boost in personal income as well as billions of dollars in tax revenues for the state and local governments.

The most optimistic – and most widely publicized – of the economic projections are contained in a [study](#) published by researchers at the University of Southern California, and funded by the state's main oil lobbying group. Several leading California economists have criticized the study's methodology, baseline data and conclusions as “unreliable.”

The USC study implicitly assumes a rapid rate of oil production growth. However, [oil company engineers and geologists](#) have not yet cracked the complex code of California's shale deposits, and large-scale production there has not yet begun. If and when they do figure out how to extract the oil, the pace of growth is uncertain.

In addition, a December 2012 [study by IHS CERA](#), a leading consulting firm to the oil and gas industry, came to markedly different conclusions from the

USC study, predicting that the Monterey Shale's promise will remain a mirage and will generate only minor economic benefit over the next two decades.

These rival forecasts seem likely to continue their role as political fodder in important policy battles. In 2014, the state will draw up new rules under a recently enacted law for oil regulations, [SB4](#); further regulations may be discussed, and the issue could also be a factor in the statewide November election.

“The numbers seem too large to be believable”

—Jerry Nickelsburg

Predictions of an epic boom

The state's emerging debate over how to regulate the oil industry was jolted in March 2013, when USC's [Price School of Public Policy](#) and [Global Energy Network](#) issued “Powering California: the Monterey Shale and California's Economic Future.” The [study](#) was funded by the Western States Petroleum Association (WSPA), which represents the state's major oil producing and refining companies, and its conclusions were attention-grabbing.

The study predicted an epic oil boom in the Monterey Shale, with the following results:

- An increase of 512,000 net new jobs by 2015 and 2.8 million net new jobs by 2020, linked directly and indirectly to oil production.
- Growth in per-capita GDP of 2.6 percent by 2015 and 14.3 percent by 2020.
- State and local government tax collections grow by \$4.5 billion in 2015 to \$24.6 billion in 2020, the equivalent of 2.1 percent and 10.0 percent growth, respectively.

Meet the experts: Economists review the USC study

- [Jerry Nickelsburg](#), Senior Economist at UCLA Anderson Forecast, the most [oft cited](#) of all economic forecasting agencies in California. Nickelsburg oversees economic modeling and forecasting for the United States, California, and the Los Angeles, Bay Area and Southern California regions.
- [Olivier Deschenes](#), Associate Professor of Economics at UC Santa Barbara and Research Associate at the National Bureau of Economic Research. His [work](#) includes extensive published research on the economic impacts of climate change.
- [Jesse Rothstein](#), Associate Professor at UC Berkeley's Goldman School of Public Policy and Department of Economics. Rothstein, a former chief economist of the U.S. Labor Department, has published often on labor markets.
- [Carol Zabin](#), Research Director of the UC Berkeley Center for Labor Research and Education. Zabin is a labor economist whose research focuses on the impact of climate change legislation and the green economy on California's economy and workforce.
- [Manuel Pastor](#), Professor of Sociology at University of Southern California. Pastor, an economist, has focused his research on economic development of low-income urban communities.

Each of the economists said the study's findings were unreliable and inflated. They cast doubt on its methodology, which did not base its estimates on any projections for oil production or capital investment in California oil; instead, the study's authors said they extrapolated from the effects of economic growth in North Dakota, South Dakota and Wyoming.

Catharine Reheis-Boyd, president of WSPA, announced [the study's conclusions](#) as "a game-changing economic opportunity that California can't afford to ignore." Later in the same day as the study's release, Gov. Jerry Brown [echoed the same note](#), saying, "The fossil fuel deposits in California are incredible, the potential is extraordinary."

In the months of legislative debate that followed, the USC report was [repeatedly cited](#) in the Legislature, with [backers](#) calling it [evidence](#) of the Monterey Shale's "magnificent potential for jobs."

But despite the report's broad influence, no independent analysis of its economic assumptions and methodology has been published to date.²² Several leading academic economists who reviewed the study were puzzled by its findings, and baffled by its methodology.

Unrealistic scenarios

"The numbers seem too large to be believable," said Jerry Nickelsburg of UCLA Anderson Forecast,²³ the state's primary economic forecasting institution.

Nickelsburg noted several factors that undermine the USC report's methodology. First, he noted that the total direct employment of California's upstream and midstream sectors was 21,244 as of 2009.²⁴ Second, by using [conventionally accepted "multipliers"](#) for calculating indirect and induced employment – that is, jobs created in other sectors by the trickle-down effect from oilfield workers and company spending – the total direct, indirect and induced employment for California's upstream and midstream sectors is "probably no more than" 100,000.

The most recent analysis of total oil and gas industry employment in California, conducted in July 2013 by PricewaterhouseCoopers and commissioned by the American Petroleum Institute, [estimated](#) that the industry employed nearly 800,000 Californians. But the economists consulted by Next Generation said that using that number as a baseline for future job growth in a boom scenario is problematic because it includes the natural gas industry, which would not be included in any oil boom in the Monterey Shale, and also includes employment in downstream sectors such as refineries and gas stations, which are unlikely to grow in any oil boom scenario.²⁵

Using even the PricewaterhouseCoopers estimate, however, USC's projections would require truly astronomical growth.

The study's scenario of 2.8 million net new jobs by 2020 represents a mean value between its low and high growth scenarios of 1,206,700 jobs and 4,425,000 jobs, respectively.

"What kind of growth rate do you need to get from there to 2.8 million jobs?" Nickelsburg asked. "This leads one to question what's really going on in this study."

The study cited its low-growth scenario as "the most conservative path, which involves what we call the "North Dakota scenario." " The study states:

We conducted analysis for California as well as three oil boom states: North Dakota, Wyoming and South Dakota. These three states have recently experienced the effects of a significant oil drilling boom.

As mentioned above, any state-to-state modeling is problematic because the publicly available employment data includes apples-to-oranges dissimilarities, including sectors that are unlikely to grow in any conceivable expansion of California oil output. Even so, the gap between the USC projections and historical trends is notable.

North Dakota experienced a [78 percent increase](#) in total employment for all industries in oil and gas producing counties from 2005–2012. In contrast, USC's median scenario projection would mean a 350 percent increase in oil and gas employment (direct, indirect and induced) from 2011–2020, and its "high-enhanced drilling" scenario would mean a 558 percent increase over the same period.

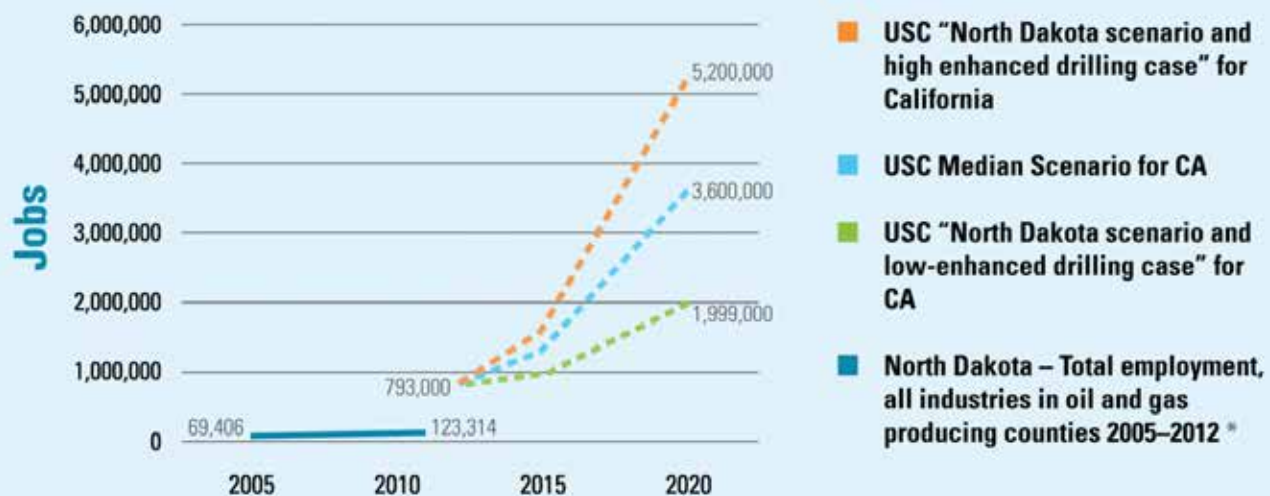
How do multipliers calculate job creation?

In assessing the economic impact of any industry, economists of all stripes use "multipliers" to determine direct, indirect and induced effects. In the case of California's oil industry:

- Direct effects result from production in the oil and gas sector itself.
- Indirect contributions result from the broader supply chain of firms supporting production.
- Induced effects result when employees of all these firms spend their incomes on consumer goods, ranging from food and clothing to medical services.

Most economists use the IMPLAN system of multipliers, which vary by sector depending on how much contracting they do locally and other factors. For example, oil refineries have an employment multiplier of 9.0343, which means that every job created directly in that sector creates 8.0343 jobs in other businesses and industries. Oil and gas drilling has a multiplier of 3.8605, while gasoline stations have a multiplier of only 1.6961.

How many jobs?



Sources: Labor Market Information Center, Job Service North Dakota 2013 using BLS QCEW estimates; American Petroleum Institute/PricewaterhouseCoopers 2013

*These figures, the most detailed publicly available for oil & gas producing counties in North Dakota, are used here in the absence of year-to-year oil & gas industry-specific job growth data.

The economists who reviewed the USC study said North Dakota is not a legitimate basis of comparison for macroeconomic projections for California, no matter what the scenario. North Dakota has a population of 700,000 people, with a small, agriculture-based economy that was proportionately overwhelmed by the state's recent oil boom. California has 38 million people and a huge, complex economy, of which the state's oil industry represents only a tiny fraction.

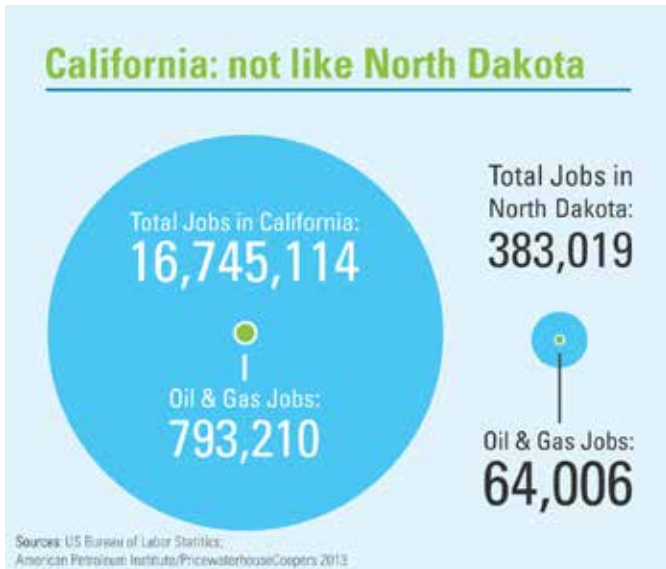
“This report’s methods are not credible”
—Jesse Rothstein

The differences compound from there: North Dakota's oil industry began its relatively fast growth rate from a very low baseline – only about 100,000 barrels per day as recently as 2006, thus statistically exaggerating its percent rate of increase to over 800,000 barrels per day currently – while California is already the nation's third largest oil producer. Using North Dakota's explosive growth as an analog to California's potential therefore exaggerates the

impact a new oil boom could have on the California economy.

“This report's methods are not credible,” said Jesse Rothstein of UC Berkeley, a specialist in labor market economics.²⁶ “It assumes that a 10 percent increase in oil and gas production in California would have the same proportional effect on the state's highly diversified economy as would a similarly sized increase in North Dakota, where the economy is much more heavily concentrated in the fossil fuel extraction sector.”

A more fundamental problem with the USC study, the economists pointed out, is that its high growth scenario appears to have no factual basis. According to oil production data from the U.S. Energy Information Administration, South Dakota and Wyoming have experienced nothing resembling an oil boom. [South Dakota oil production](#) increased from 4,024 barrels per day in 2005 to 4,805 barrels per day in 2012 – a 3 percent annual increase and close to the state's trend over recent decades. [Wyoming's oil production](#) grew during that period from 141,838 barrels per day to 158,123 barrels per day – a 1.8 percent annual increase. Over the past three decades, Wyoming's production has decreased by more than 50 percent overall.



Peter Gordon, the primary co-author of the USC study's economic projection, offered the following explanation for the inclusion of references to South Dakota and Wyoming:

Ours is a standard time series model. We analyze California trends with two tweaks: 1. New oil drilling forecasts from EIA; 2. A new California GDP-to-drilling relationship. We took this one from the North Dakota experience to 2010, the early part of their boom and the most conservative of the oil boom states we evaluated. 3. Our baseline for California was a trend extrapolation of California GDP growth. It is as simple as that. Given our time and budget constraints, this is all we could do.²⁷

Other experts who reviewed the USC study were puzzled by Gordon's response.

"As others have mentioned, the methodology is not transparent," said Olivier Deschenes of UC Santa Barbara, a specialist in econometrics and labor markets.²⁸ "I did not understand the methodology for the employment impacts."

Deschenes particularly questioned the study's macroeconomic analysis and modeling. "I spent two hours reading Chapter 3 and I continue to have a hard time understanding how the numbers in the tables are computed."

Part 6: Keeping the story straight: industry reports at odds on California oil

California's growing debate over the environmental risks of oil production has echoed with claims that an oil boom lies just around the next bend – as long as we keep overly harsh regulations from steering us off the tracks.

Expectations have been bolstered by a [study](#) by the University of Southern California that projected millions of new jobs and billions of dollars in tax revenue for the state and local governments. The study was paid for by the Western States Petroleum Association (WSPA), the California oil industry's main lobbying organization. But some of the state's leading economists view these promises as [unreliable and based on incorrect assumptions](#).

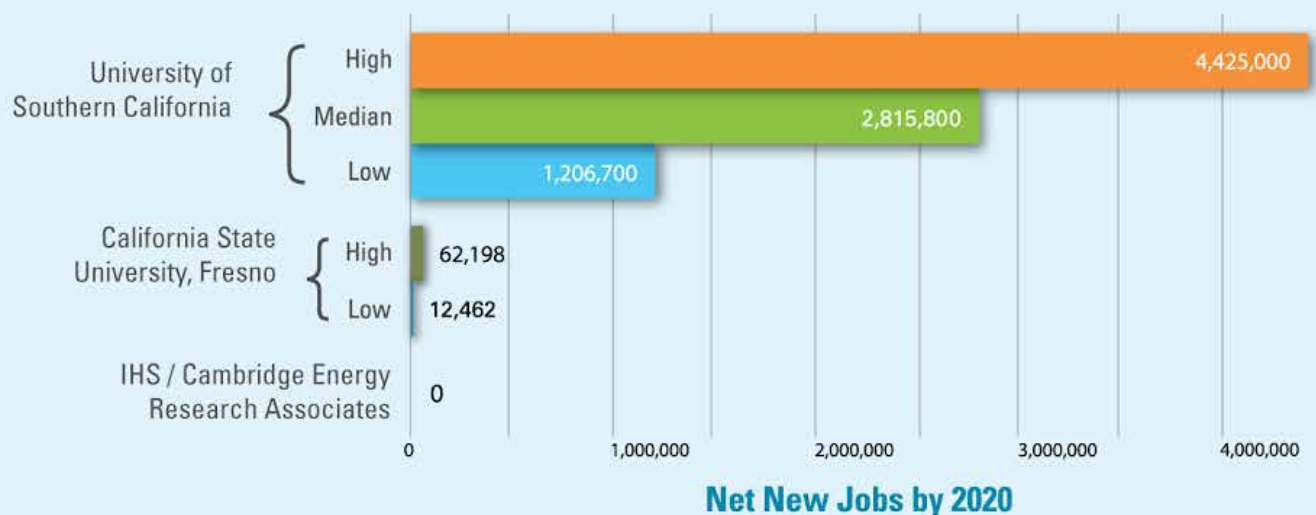
More broadly, the question of whether the Monterey Shale will bring more prosperity to the state remains unanswered. As California continues debate over oil policies in 2014 and beyond, the [realpolitik of jobs and the economy](#) will remain as central to decision making as it always has been in American politics.

Cold water from an unlikely source

Debunking of the USC study has come recently from an unlikely source – a separate study commissioned by WSPA. Antonio Avalos and David Vera, economics professors at California State University at Fresno, were commissioned by WSPA to carry out projections of economic impact only for the San Joaquin Valley. Their report, "[The Petroleum Industry and the Monterey Shale: Current Economic Impact and the Economic Future of the San Joaquin Valley](#)," released in October 2013, predicted much more modest job gains under two scenarios:

- Between 2,151 and 9,347 net new jobs (direct, indirect and induced) by 2020 under what Avalos and Vera call the "high resource scenario," equivalent to the U.S. Energy Department's predicted rate of growth for "tight" shale oil nationwide.
- Between 2,151 and 46,649 net new jobs by 2020 under a "high resource-oil boom scenario," equivalent to the North Dakota rate of growth.

A vast gulf in jobs data



Because the eight-county San Joaquin Valley studied in the CSU Fresno report accounts for three-quarters of California's oil production, [according to state data](#), the high-growth projection of 46,649 jobs by 2020 would be the equivalent of roughly 62,198 new jobs statewide²⁹ – far less than the USC study's median prediction of 2.8 million new jobs. However, even the CSU Fresno study's numbers must be discounted somewhat because they include jobs in refinery production and gasoline station sales, neither of which would be likely to grow in any oil boom scenario.

Vera says that that the CSU Fresno report and the USC version “are not fully comparable,” but declined to comment otherwise on the contrast between the results:

Our study focuses on the San Joaquin Valley only, while the USC study examines the entire State of California. The difference in scope leads to major differences in data availability and thus in methodology. For example our main variable in the forecasting exercise is real personal income at the county level while for the USC report is real GDP per capita at the state level, not available at the county level. Consequently, findings in the reports are not fully comparable.

Refineries, gas stations unlikely to see job increases

California's upstream and midstream sectors, which comprise oil exploration/production and transportation, respectively, would be directly affected by any oil production increase in the Monterey Shale. In contrast, the downstream sector, which comprises refineries, petrochemicals, wholesale and retail, is likely to remain unaffected by any such increase, for several reasons:

- As noted in [Part 4 of our series](#), the state's [18 oil refineries](#) have a [total capacity](#) of about 2 million barrels per day, of which California's current oil production supplies only about one-quarter, thus giving the state much excess capacity to absorb local production without building new refineries.
- Given the state's political and regulatory climate, companies would find it extremely difficult to get regulatory approval to build new refinery capacity, as shown by Chevron's [recent difficulties](#) in trying to expand its Richmond refinery.
- Federal law imposes a virtual ban on exports of crude oil to other nations.
- California has no significant pipelines that could be used for shipping to other U.S. states, and obtaining permits to build any such pipelines through California would be politically very difficult.
- California's retail gasoline prices are highly unlikely to be depressed by local fuel supply, just as the glut of crude in Cushing, Oklahoma, has not seriously affected gas prices elsewhere in the nation.
- California drivers are not going to drive more miles or buy more gas-guzzling cars just because their gasoline and diesel is locally pumped rather than being imported from Saudi Arabia or Ecuador.
- While [roughly 50 percent](#) of California's total refinery capacity is for production of gasoline, the rest is for diesel, aviation and bunker fuels, chemicals, asphalt and other products, none of which are likely to sell more just because the petroleum from which they are sourced is locally produced.
- California's [exports of refined petroleum products](#), including petrochemicals, have fluctuated since the 1980s with no measurable decrease despite the 50 percent drop in the state's oil production during that period. Because of this de-linkage, it seems unlikely that exports of refined petroleum products would increase substantially if in-state crude production were to increase.
- California's refining capacity is configured for a wide range of oil viscosity, including heavy imported crude. So a switch from imports to local crude would not necessarily require significant equipment modifications.

(...) We did not have access to the raw data or any of the code used in the estimations in the USC report. The USC report does not clearly explain the methodology or data employed (...) It may be valid, we just can't tell with the information that is available.³⁰

Interestingly, WSPA has repeatedly publicized the results of the USC study, but has put little effort into publicizing the results of the CSU Fresno study.

“There has been a lot of speculation and debate about the Monterey Shale, but our energy team does not see those results.”

—Mohsen Bonakdarpour

Managing director of IHS Economics.

Industry's top consultants predict no new jobs

An even more bearish set of conclusions about Monterey Shale job growth has come from yet another unlikely corner – the petroleum industry's leading consultancy, [IHS CERA](#). The firm, headed by Pulitzer Prize-winning author and pundit Daniel Yergin, has close ties to major oil firms and often takes bullish views of production potential. But IHS CERA's December 2012 report, [America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy, Volume 2: State Economic Contributions](#), concluded that California's "unconventional" oil sector, which is almost entirely synonymous with the Monterey Shale, will produce almost zero new oil or new jobs for at least the next decade. Its chief conclusions were these:

- California unconventional oil will produce virtually nothing through 2020, then 10,000 barrels daily in 2025, 40,000 barrels daily in 2030, and 60,000 barrels per day in 2035. These amounts are small fractions of the state's overall output of 536,000 barrels daily, and they comprise an even tinier fraction of the bonanza promised by the oil lobby.
- California jobs, income and tax revenues will experience modest increases – but with a huge caveat. By 2020, net new jobs (direct, indirect and induced) are projected to increase by 57,105, annual labor income will rise by \$3.8 billion, and state and local tax revenue will jump by \$1.6 billion. However, because in-state oil production is expected to be flat, these benefits will be generated only by spill-over spending from other states such as North Dakota and Texas as California-based companies Chevron and Occidental benefit from out-of-state work. Examples could include additional income to headquarters employees or stockholders of these companies, out-of-state work by California-based consultants and oil service providers, or exports by California manufacturers of oilfield equipment. Oil production from the Monterey Shale will add no direct, indirect or induced economic benefits.

In subsequent interviews, IHS-CERA experts stood behind the study's findings of negligible job growth. Mohsen Bonakdarpour, managing director of IHS Economics, said:

*There has been a lot of speculation and debate about the Monterey Shale, but our energy team does not see those results. We have much more conservative estimates for California.*³¹

Pete Stark, the IHS-CERA research director on unconventional oil, said oil companies' success in North Dakota and Texas shale was likely to be stymied in the Monterey:

We have followed Monterey activity with interest but have observed little evidence that the local operators have broken the code to unlock production from this complex package of tight rocks. ... We have characterized the Monterey with Churchill's pertinent observation about Russia – 'It is a riddle, wrapped in a mystery, inside an enigma.' It will take substantial R&D investment and time to understand and unlock even part of the technically recoverable oil cited by the EIA. We expect that operators like Oxy ... will peck away with close-in development drilling in and around the old producing fields and structures. This will yield more of the tight oil resource. If companies unlock oil production from deeper zones within active oil generating systems this could increase volumes of lighter oil similar to that from the large tight shale oil plays like the Bakken and Eagle Ford. Apart from that we will continue to track activity but will not hold our breath awaiting a game changer.³²

Although the IHS-CERA findings were the first comprehensive expert analysis of the Monterey Shale's potential, they appear to have gone entirely unnoticed. Database searches on Google and Nexis reveal no mention anywhere of the IHS-CERA findings on California from the report's release in December 2012 to the present.³³

The IHS-CERA pessimism about the unconventional oil in the Monterey Shale received the tacit backing of the U.S. Department of Energy in mid-2013 when the Department released its [Annual Energy Outlook 2013](#).

Under its "high resource" scenario – essentially the most optimistic boom conditions – total U.S. national oil production would rise by more than one-third during 2013-2020, but California's total production would fall by 6.5 percent. Although the report did not specify how much of the state's production was likely to come from the Monterey Shale, it made clear that the results there would be minuscule.

Weak grounds for boom boosterism

So is California on the verge of a historic oil bonanza that will bring a surge in prosperity, as the USC study claims? Or will the results be slim pickings, as most other experts believe?

Under any scenario, California could use more jobs – the state still had 1,611,926 unemployed workers as of October 2013.³⁴ But California has already been [adding about 300,000 net new jobs annually](#) since mid-2010, when the economic recovery began, according to federal labor data. While an oil boom, even an unlikely one, would clearly add some jobs, it's worth taking the time to understand the true employment implications of a boom – and weighing those against the environmental and climate implications of drilling and burning more oil.

But such a boom is still a hypothetical, future event. In the meantime, the state can continue pursuing its role as a global leader in clean energy job creation, climate change mitigation and preparedness, and overall quality of life. Regardless of what happens with the Monterey Shale, the state's diverse economy and penchant for technology innovation are likely to continue to be the real California Gold Rush.

Notes

¹ In addition to the primary acid components, other chemicals used include surfactants, solvents, corrosion inhibitors and oxidizers. The acid solution may also be applied in other forms such as foams, gels or emulsions. The volume injected is typically low, such as 5 gallons per well foot, but there are reports that [higher volumes of as much as 250 gallons per foot](#) are being used.

² Interview with author at “Tight Oil Reservoirs California” conference, Bakersfield, May 30, 2013.

³ Interview with author at “Tight Oil Reservoirs California” conference, Bakersfield, May 29, 2013.

⁴ http://www.jmaterenvironsci.com/Document/vol3/vol3_N5/87-JMES-234-2012-Puthalath-review.pdf
<http://www.onepetro.org/mslib/servlet/onepetroreview?id=NACE-03121>
<http://www.onepetro.org/mslib/servlet/onepetroreview?id=00038594>

⁵ Personal communication to author, June 14, 2013.

⁶ Telephone interview with author, July 13, 2013.

⁷ A written non-response came from Halliburton, one of the state’s primary oilfield services providers. In a [June 12, 2013 letter to Pavley](#), the company’s Director of State and Local Governmental Affairs, Stephen Flaherty, responded that the company’s “services comply with all applicable health and safety laws and regulations, and works with its customers to ensure that compliance . . . I am sure you understand that as a matter of company policy and practice Halliburton does not speak to questions about the particular services it provides to, or the circumstances of, its individual customers.”

⁸ Email to author, July 25, 2013, from Alison apRoberts, information officer, California Energy Commission: “California onshore crude oil production peaked in 1985 at 354.8 million barrels. Onshore production last year tallied 182.2 million barrels. So one could say that there was a system in place of pipeline connections to handle 172.6 million barrels more than today. What portion of that 1985 distribution capacity may have been retired or mothballed is unknown but likely only a modest portion. In addition, refiners and other parties in California are continuing to pursue rail-by-crude projects to take advantage of less expensive crude oil opportunities like Bakken and Canadian crude oils. This means that new crude oil production in California could be loaded onto rail cars for delivery to refineries that have rail receipt capability. This trend in conjunction with the state’s spare pipeline capacity can therefore negate the need to build additional pipeline capacity over the near to mid-term.”

⁹ Email to author, Aug. 10, 2013.

¹⁰ Email to author, Aug. 13, 2013. Medlock continued: “Firms will, however, make an assessment of the direction of the market before

actively developing a field. But, there are many factors that go into such an assessment, such as global economic health and demand growth (China demand is a huge issue at the moment), and trends in various things that effect global supply (such as growth in Iraqi production, what is happening in West Africa, what is happening generally with light tight oil production across the US, what is happening with Canadian oil sands, etc.).”

¹¹ Email to author, Aug. 10, 2013.

¹² Telephone interview, May 13, 2013

¹³ Telephone interview, May 10, 2013.

¹⁴ Interview, May 14, 2013.

¹⁵ Interview, May 24, 2013.

¹⁶ Email to author, July 25, 2013, from Amgad Elgowainy, Principal Energy Systems Analyst of the Argonne National Laboratory’s Center for Transportation Research.

¹⁷ In recent months, the Western States Petroleum Association and researchers at UC Davis have engaged in a [vigorous back-and-forth debate](#) over the effects of AB 32 on the refining sector. These important issues are separate from the subject matter at hand.

¹⁸ With API under 10 and 20, respectively.

¹⁹ Interview, May 14, 2013.

²⁰ Interview, May 24, 2013.

²¹ Telephone interview, May 13, 2013

²² A very useful critique of oilfield production scenarios, including those related to the USC report, is contained in a December 2013 report by J. David Hughes for the Post Carbon Institute and Physicians Scientists & Engineers for Healthy Energy. Drilling California: A Reality Check on the Monterey Shale, available at www.postcarbon.org/reports/Drilling-California_FINAL.pdf

²³ Telephone interview, July 29, 2013

²⁴ “Assessment of Petroleum Industry Economic Impact to the State of California,” Purvin & Gertz, 2011. Available [here](#).

²⁵ According to the economists consulted by Next Generation, the downstream sector, which comprises refineries, petrochemicals, wholesale and retail, is likely to remain unaffected by a boom in oil production in the Monterey Shale, for several reasons: A) As noted in [Part 4 of our series](#), the state’s [18 oil refineries](#) have a [total capacity](#) of about 2 million barrels per day, of which California’s current oil production supplies only about one-quarter, thus giving the state much excess capacity to absorb local production without building new refineries; B) given the state’s political and regulatory climate, companies would find it extremely difficult to get regulatory

approval to build new refinery capacity, as shown by Chevron's [recent difficulties](#) in trying to expand its Richmond refinery; C) federal law imposes a virtual ban on exports of crude oil to other nations; D) California has no significant pipelines that could be used for shipping to other U.S. states; E) California's retail gasoline prices are highly unlikely to be depressed by local fuel supply, just as the glut of crude in Cushing, Oklahoma, has not seriously affected gas prices elsewhere in the nation; F) California drivers are not going to drive more miles or buy more gas-guzzling cars just because their gasoline and diesel is locally pumped rather than being an import from Saudi Arabia or Ecuador; G) While [roughly 50 percent](#) of California's total refinery capacity is for production of gasoline, the rest is for diesel, aviation and bunker fuels, chemicals, asphalt and other products, none of which are likely to sell more just because the petroleum from which they are sourced is locally produced; H) California's [exports of refined petroleum products](#), including petrochemicals, have fluctuated since the 1980s with no measurable decrease despite the 50 percent drop in the state's oil production during that period. Because of this de-linkage, it seems unlikely that exports of refined petroleum products would increase substantially if in-state crude production were to increase; I) California's refining capacity is configured for a wide range of oil viscosity, including heavy imported crude. So a switch from imports to local crude would not necessarily require significant equipment modifications.

²⁶ Personal email, July 10, 2013

²⁷ Personal email, July 18, 2013

²⁸ Personal email, July 30, 2013

²⁹ This may slightly understate the statewide total because it does not account for headquarters and services jobs outside of oil-producing regions, but any undercounting would be minuscule in comparison with the large discrepancy in overall projections.

³⁰ Personal email, Nov. 4, 2013

³¹ Telephone interview, Oct. 1, 2013

³² Personal email, Oct. 1, 2013

³³ The IHS-CERA communications team promoted the overall report in press releases and other materials but did not mention its unusual California findings.

³⁴ Recent net job growth for California: 217,443 from January through October of 2013; 326,937 in 2012; 294,092 in 2011. Accessed here.