The Oregonian

Kill Oregon's low-carbon fuel standard

By The Oregonian Editorial Board
November 05, 2012

Note to the Oregon Legislature: Applying the keep it simple, stupid (KISS) principle in state government is not a form of sexual harassment. We thought that was worth mentioning given the fact that Oregon's dauntingly complex low carbon fuel standard is slouching toward implementation. It's time to KISS this thing goodbye.

The standard, adopted by the 2009 Legislature in a highly partisan green frenzy, mandates a 10 percent carbon reduction in Oregon fuels over the course of a decade. This may sound simple, but making the requirement workable has been a slow and difficult process, owing to the enormity of the undertaking and to a requirement that the standard not boost fuel prices, which is about as likely as Superman donning kryptonite BVDs.

The process has involved dozens of advisory committee members, multiple contracted private firms and abundant Department of Environmental Quality staff time. It has taken so long that Richard Whitman, Gov. Kitzhaber's natural resources policy director, warned earlier this year that the Legislature would have to adjust the original bill's 2015 sunset date if the program is to get off the ground. But rule-making would go forward.

Thus, the Department of Environmental Quality will ask the Environmental Quality Commission in December to adopt administrative rules implementing the first part of the fuel program, a two-year reporting phase to begin in 2013. Assuming the Legislature adjusts the sunset date, the second phase -- the carbon-reduction bit -- would begin in 2015. The EQC in December will be asked to adopt a loose set of rules for that phase, too, and they'll be refined at a later date.

All of which means Oregonians should hold onto their wallets and prepare for an eco-friendly train wreck. This program is nuts.

The Portland Business Alliance said as much, only politely, in an Oct. 9 letter to the DEQ. The standard, the PBA wrote, would "increase costs and impose a competitive disadvantage for Oregon businesses," as of course it would. The letter also notes that efforts to reduce greenhouse gas emissions are best left to the federal government, which has not been what you'd call inactive in this area.

For a more blunt assessment, consider a letter to DEQ written in 2010 by Frank Holmes of the Western States Petroleum Association, which represents wholesalers. Holmes, one of the program's many advisory committee members, argued that the "multitude of complex issues" wrapped up in the standard would make its administration and implementation "almost incomprehensible."

He couldn't be more correct.

The program, for instance, won't target merely the carbon in the fuel itself. Rather, it assigns "carbon intensities" to various fuels based on a "lifecycle assessment" that considers greenhouse gas emissions from their production, storage, transportation and combustion. In a 2011 report explaining the program's design, which exceeds 170 pages without appendices, DEQ even proposes to update the carbon intensity of Oregon's diesel and gas imports periodically to account for the larger share likely to come from Canada's tar sands, which require lots of energy to process. And because the carbon intensities of various fuels vary widely, the required carbon reductions would be achieved, in part, by buying and selling credits.

Should the Environmental Quality Commission adopt the rules in December, the first phase of the program will require distributors and others to report how much of each kind of fuel they handle. Because somebody at the DEQ would have to process all of that information, the agency will ask the Legislature next year to sign off on the addition of two new employees to do the work and, naturally, to approve fees.

And the second phase, should it come to pass, would drive up the use of alternative fuels, which means it's certain to boost prices at the pump. The program does provide a safety net for consumers, as required by law, but it's still a work in progress, says DEQ head Dick Pedersen. As laid out in the 2011 report, though, the basics are far from reassuring. Here's how it would work: The state would track prices using a rolling 12-month weighted average in Oregon, which it would compare with a similar average in neighboring states. If Oregon prices were 5 percent higher than those elsewhere, the DEQ would investigate whether the fuel standard is the culprit, then make a recommendation to the EQC. In order to relax the standard, the commission would have to determine that other factors aren't to blame for price hikes, and even then it would have to determine that relaxing the standard was necessary to mitigate the increase.

In the meantime, consumers would be paying through the nose.

Even if the EQC decided to suspend the fuel requirement, the decision would probably create great difficulties for the people who sell fuel. Wholesalers have long-term contracts with ethanol providers, for instance, as well as standing fuel supplies, says Brian Doherty, who represents the Western States Petroleum Association. "It sounds like we can just stop and let prices come down," he says, but – like so many other aspects of the fuel program – the reality is complex.

Fortunately, the solution to the innumerable problems posed by the low-carbon fuel standard is simple. First, the EQC should decline to adopt the new rules in December. Second, the Legislature should kill the standard in 2013. From PERS costs to high unemployment, Oregonians have more than enough complicated problems to worry about these days without shouldering voluntary burdens like this one.

Oregon's clean-fuel folly continues

By The Oregonian Editorial Board The Oregonian
December 10, 2012

The low-carbon fuel standard will weigh the greenhouse gases generated during the production, storage, transportation and combustion of various fuels, including biofuels. Above is the Imperium biodiesel plant in Hoquiam, Wash., seen here in 2007.

AP Photo/Ted S. Warren The costly mandate officially known as the Oregon Clean Fuels Program made a small but meaningful claim on your wallet last week.
On Friday, the state Environmental Quality Commission approved a stack of administrative rules that will expand paperwork obligations for both public and private entities. Oregon fuel producers and importers will incur compliance costs of at least $2.2 million in 2013 alone, according to a Department of Environmental Quality estimate. Meanwhile, the DEQ itself intends to ask lawmakers for permission to spend almost half a million dollars during the coming biennium to hire new staff and pay for consultants.

Ultimately, Oregonians will pick up the tab, largely through the cash they spend at the pump.

Things could be worse. The rules approved Friday govern the first -- and less costly -- half of a two-part program whose full implementation hinges on legislative action next year. Oregonians will know soon enough whether their representatives would rather pursue green bragging rights or affordability and economic competitiveness.

There's no doubt where the Legislature's priorities were in 2009, when it created the Clean Fuels Program. This was the same highly partisan group, after all, that approved the income- and business-tax hikes that voters later encountered as Measures 66 and 67.

The goal of the Clean Fuels Program is to cut the lifecycle greenhouse gas emissions of fuels sold in Oregon by 10 percent over a 10-year period. Lifecycle emissions include not only the gases generated by the combustion of fuels, but also gases loosed during their development, transportation and storage. A gallon of gasoline refined from oil pumped from a nearby well, then, would have a lower carbon intensity than a gallon of gas refined from oil extracted from Canada's oil sands.

The complexity of this undertaking is daunting, and the eventual effect on fuel prices will be significant. The law does require the program to include a safety-valve provision to protect consumers from price spikes, but the mechanism as currently structured is complex and doomed to fail. Using rolling 12-month averages, the state would compare fuel costs in Oregon with those in neighboring states. If prices here exceed those elsewhere by at least 5 percent, DEQ would try to find out whether the fuel standard was to blame, then make a recommendation to the Environmental Quality Commission. The EQC would then exercise its own discretion and maybe -- maybe -- relax the standard here.

In other words, fuel prices are certain to jump substantially if the carbon-reduction portion of the fuels program goes into effect, and the likelihood that the state will step in to help consumers is almost zero. But that's inevitable. A mandate that increases the use of "clean" fuels -- as this would -- without also ramping up costs is a public policy unicorn. It's nice to imagine, but it's pure fantasy.

Fortunately, the 2009 law contains a 2015 sunset date. State officials have decided that this leaves enough time to require fuel producers and importers to track the carbon intensity of the fuels they handle, beginning next year. But the second half of the Clean Fuels Program -- the carbon-intensity reductions and sizable price hikes -- won't happen unless lawmakers remove the sunset date. The DEQ will ask the Legislature to do this in 2013, and additional pressure will come from environmental groups and biofuel manufacturers, who stand to profit from the program.

Lawmakers should have the guts to say "no" and sit on their hands. Oregon can't hope to dent global greenhouse gas production by fiddling with its fuel supply, but the effort will harm Oregon consumers and businesses. That's a bad trade-off.

The East Oregonian
EDITORIAL: To help environment, look elsewhere than Clean Fuels Program
East Oregonian Editorial Board | Posted: Tuesday, March 12, 2013 7:10 pm

The Oregon Legislature must make a decision on the future of the Oregon Clean Fuels Program.

If legislators do nothing, the program will expire in 2015. If they extend and enhance it with Senate Bill 488, Oregon will remain on the path to require that suppliers and distributors cut the amount of carbon in most car and truck fuels by 10 percent by 2025.
The Clean Fuels Program was first authorized by the Legislature in 2009. Proponents say it will increase investment in regionally-produced biofuels and reduce both our dependence on foreign oil and our carbon footprint.

Detractors say it is just another mandate that would increase gas prices and burden consumers while making negligible, if any, environmental impact.

Smartly, the bill's proponents have allowed for some "off ramps" that could temporarily or permanently halt the program if, for example, gas and diesel prices spike solely because of the clean fuel requirements when they are implemented.

Jana Gastellum, climate protection program director for the Oregon Environmental Council, said she appreciates having the ability to reign back the program if it has a serious influence on prices, but she doesn't think it will. In fact, she told the East Oregonian editorial board that Oregonians could see reduced fuel costs, and that the state could benefit from more than 800 jobs and billions of dollars of new investment and personal income.

There are real benefits already being seen in Eastern Oregon. The Pacific Ethanol facility at the Port of Morrow, which generates ethanol and blends it into gasoline, employs 36 people, produces millions of gallons of fuel and $20 million worth of grain-based ethanol byproduct sold as cattle feed.

And other benefits could come to our side of the state, including an expansion of the ZeaChem plant (see the story in today's paper). Biodiesel is often made with corn, wheat, woody biomass and other plant products that could be grown here in Eastern Oregon as well, benefitting us twice: in initial production and again as an added-value good.
Port of Morrow executive director Gary Neal called companies like ZeaChem and Pacific Ethanol "entirely dependent" on the clean fuel program.

Yet, there is that pesky big picture. Is all this investment, technology and biodiesel fuel making the world a healthier place? It's debatable. Biodiesel has lower fuel economy and power than its gasoline counterpart, according to the
Department of Energy. That means the 10 percent reduction of oil in your tank may be offset by more trips to the pump.

In our opinion, the best bang for our tax buck for reducing our carbon footprint is research and development into new technologies on the other side of the ledger: in the engines themselves, as well as production of renewable energy.

No one is pleased to fill the gas tank, especially when we think that much of it comes from countries that harbor horrendous human rights records and anti-American extremists. No one is pleased, either, when it takes a few more bucks to fill that tank each time.

If the Clean Fuels program reduced our dependence on foreign oil, increased investment in our state, produced affordable and efficient fuels and saved the environment, we would be in favor of it. Yet those are four big "ifs" and not one of them is a sure thing. More likely, the program would reduce gas mileage and have little impact on consumption of foreign fuels.

Oregon has long been a leader in environmental thinking, and there is no sign of slowing up now. We believe our energies and our tax dollars, however, would be better spent elsewhere than the clean fuels program.

By 2025, we expect that our vehicles will be using much less than 90 percent of what what we are using today.

The majority of that decrease will come from other technologies, however, and won't need government mandates to convince consumers.

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St. Helens Chronicle
Guest editorial:

Low carbon fuel standard misses the mark

Tuesday, March 12, 2013
Kevin P. Owens, P.E. Oregonians for Sound Fuel Policy; General Manager, Columbia River PUD

For those of us who are used to the many balancing acts of life – whether as parents, small business owners, hard-working employees or community leaders – we know the value of both good information and good intentions.

So on its face, it would seem pretty easy to support a program with a name like the Clean Fuels Program. The problem isn't in the name, however. Like so many things built on good intentions, the devil is in the details. In the case of a proposed Low Carbon Fuel Standard, four "details" help demonstrate the program's fatal flaws: First, a Low Carbon Fuel Standard, according to independent studies, will almost certainly drive up fuel-production costs by as much as a dollar a gallon. For those of us that remember the summer of 2012, higher fuel costs are an unwelcome possibility. Higher fuel costs would hurt the most those who would be least prepared or able to withstand the hit – low-income families, small businesses, communities most dependent on people and goods coming from far away – be they tourists or freight trucks.

Second, contrary to what LCFS advocates may say, Oregon's emerging biofuels industry is being driven by Oregon's Renewable Fuel Standard (RFS) and also by the Federal RFS2 program. These standards aren't going anywhere, and they provide the stability and incentives needed to continue attracting fuel-innovation investments and entrepreneurship.

Third, the LCFS ignores, at the peril of Oregon's families and small businesses, the current low-carbon fuel supply reality: there is already not enough domestic low carbon fuel to meet the proposed LCFS. By 2018, there won't be sufficient international, imported low-carbon fuels to meet the requirements (this is true even setting aside the head-scratching logic of "decreasing" Oregon greenhouse-gas emissions by shipping in Brazilian sugar-cane ethanol from thousands of miles away).

Lastly, Oregon's LCFS is based heavily on the only LCFS currently in place in the nation, California. However, California's LCFS was ruled unconstitutional and is currently tied up in appeals. Further, a quick recap of the program's troubled existence shows further problems.

In 2009, the Oregon Legislature passed HB 2186, which allowed the Environmental Quality Commission ("EQC") to consider adopting an LCFS. The Legislature did not, however, vote to adopt an LCFS. That 2009 legislation contained a 'sunset clause' of Dec. 31, 2015, to maintain legislative oversight of such an unproven program.

In December 2012, after significant questions about the feasibility and cost of the program were raised by the EQC, the Department of Environmental Quality withdrew the draft implementation rules for this program.

Now, four years after HB 2186's passage, and despite confusing, incomplete rules and repeated setbacks, DEQ is asking legislators to support SB 488, which would unnecessarily remove the sunset on this program without being able to demonstrate that the program can even work, let alone overcome its many complexities. Oregonians deserve public policy based on science and data, not solely on good intentions and wishful thinking. The proposed Low Carbon Fuel Standard (Clean Fuels Program) is unfortunately the latter.

As Oregonians who care about both our economy and our environment, we have a responsibility to hold DEQ to its promises and responsibilities. For that reason, we urge our lawmakers to vote "no" on SB 488, in order to maintain the 2015 "sunset" clause and shield Oregon's businesses and families from fuel supply instabilities just as Oregonians are starting to get their feet back under themselves.

Impact of a Low Carbon Fuel Standard in Oregon

Three reasons a Low Carbon Fuel Standard in Oregon is a BAD idea

- Economic pain to Oregon families would be significant
- Feasibility of compliance unlikely given availability of low carbon fuel
- Constitutionality of similar proposal in California is in question

LCFS comes at a high cost to Oregon families

- Loss of 9,000 to 29,000 Oregon jobs
- Costs to Oregon families up to $1,200 per year in fuel costs
- Decrease in state economic activity by a minimum of $600 million
- Additional cost to Oregon families for environmental benefits already created through Federal RFS

Source: Charles Rivers Associates, analysis of Oregon Clean Fuels Program, April 12, 2011

LCFS comes at a high cost to Oregon families

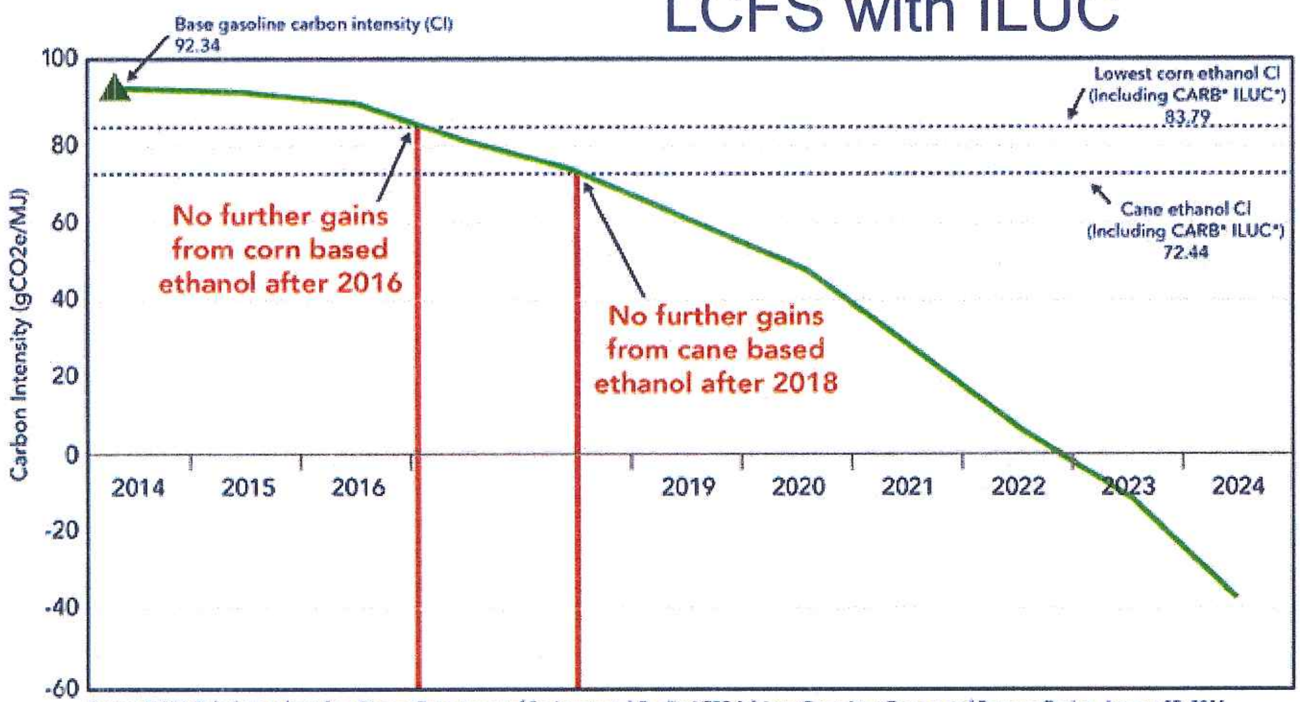
- Under California's LCFS, refiners will have to recover 33 cents to $1.06 per gallon to cover higher costs associated with the mandate
- Compliance costs could be much higher if the cost of carbon rises and becomes volatile – up to $2.70 per gallon
- Massive shift in fuel trade flows

Source: *Understanding the impact of AB 32,* Boston Consulting Group, June 6, 2012, www.cafuelfacts.com.

Additional mandates for cellulosic biofuels are neither necessary nor feasible

- Advanced biofuel technology – including cellulosic – is already being mandated by Federal RFS program

Example of ethanol CI required for 10% fuel blend under OR LCFS with ILUC



Source: WSPA Calculations based on Oregon Department of Environmental Quality LCFS Advisory Committee Process and Program Design, January 25, 2011
* CARB - California Air Resource Board | ILUC - Indirect Land Use Charge

No commercially available blending options

Constitutionality of similar proposal in California is in question

- U.S. District Judge Lawrence J. O'Neill ruled in December 2011 the California LCFS is unconstitutional because it:
  - ✓ Discriminates against crude oil produced outside the state
  - ✓ Discriminates against ethanol produced outside the state
  - ✓ Impermissibly attempts to regulate commerce outside of the state's borders
- October 16, 2012 CARB appeal argued in 9th Circuit Court of Appeals
- Decision expected in 2013

What others are saying about Oregon's LCFS

"We are concerned that the rules proposed by DEQ…will be extremely costly and potentially harmful to the economy."

– AAA Oregon/Idaho

"Our organizations strongly oppose implementation of the proposed low carbon fuel standard (LCFS) for Oregon because it would lead to higher fuel costs, hurt the state's economy, and destroy jobs, and would result in no detectable impact on global warming."

– Oregonians for Balanced Climate Policy

"High fuel prices from a state-specific low carbon fuel standard will be a major deterrent to job creation in this state."

– Oregon Petroleum Association

OREGON FARM BUREAU

AOI Associated Oregon Industries

OPUDA OREGON PEOPLE'S UTILITY DISTRICT ASSOCIATION

AGC Oregon Columbia Chapter ASSOCIATED GENERAL CONTRACTORS

OPA OREGON PETROLEUM ASSOCIATION

OTA

Conclusions

- If enacted, fuel prices are likely to increase significantly causing great harm to Oregon families
- Compliance is infeasible given low carbon fuel availability
- An LCFS in Oregon would be questionable constitutionally

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QuantEcon, Inc.

Economics and Finance Consulting

DATE	August 29, 2012
FROM	Randall Pozdena, PhD, President, QuantEcon, Inc.
TO	Oregon Environmental Quality Commission
SUBJECT	Testimony regarding LCFS implementing regulations

INTRODUCTION

The Oregon Legislature asked the Oregon Department of Environmental Quality to prepare implementing regulations related to the imposition of Low Carbon Fuel Standards on fossil fuels. The intended purpose of the LCFS is to reduce emission of carbon dioxide into the atmosphere and thereby spare the economy the economic burden that these emissions will impose on future generations.

As an economist with almost 40 years of experience studying regulatory and market behaviors, I feel compelled to comment on the fundamental weaknesses of the LCFS. I have concerns about its viability as a method for achieving its stated emissions goals and its claimed economic benefits. I believe it will fail on both fronts for at least four reasons:

1. Quantitative regulations ("standards") are inherently inefficient and ineffective because the market is too complex to be monitored and manipulated by administrative procedures and policies. Only pricing mechanisms actually remedy the underlying defects in public policy that keep private markets from addressing environmental externalities. Hence, only a price mechanism can nudge the myriad interactions of market participants toward a more carbon-lite future in a truly resource-sparing, efficient manner.

2. The fact that the proposed LCFS includes various "off-ramps" or deferral mechanisms is disturbing for two reasons: (1) it is clear that DEQ itself does not know if the program will perform as intended or, instead, backfire on the environment and economy; and (2) the associated complexity of implementing these safeguards poses complex problems of measurement, implementation, and bureaucratic discretion, all of which will cause collateral damage in real marketplaces.

3. As a state with no indigenous petroleum refining capacity, and as a small player in the market for fossil fuels, Oregon has no realistic prospects of of influencing technological developments, production or pricing of fossil or biofuels, but great prospects of being vulnerable to out-migration of economic activity from the state and having its program (including off-ramp policies) affected by other markets' regulatory and market behavior.

4. I have already provided testimony that the LCFS will fail to generate Oregon jobs, a collateral benefit claimed by DEQ in advancing the LCFS. The DEQ analysis in this regard is based on simplistic models, unlikely assumptions, and not supported by other empirical simulations or theory.

In the remainder of this testimony, I elaborate briefly on each point above. I will reference, but not repeat my prior testimony.[1]

WHY REGULATORY STANDARDS FAIL

Using quantitative regulation to control the content or volume of a commodity sold in an economy is always more costly than the use of a pricing mechanism to achieve the same goal. Period. Indeed, given the abject failure of economies based on command-and-control techniques, let alone the poor track record of its application in selected markets in otherwise market-based economies, it is curious that regulation survives as the tool of choice of so many policy makers. Quantitative regulation has been known for over a century to be prone to creating "dead-weight losses", i.e., wasteful use of resources.

It may be easier to illustrate what I mean about dead-weight resource losses with a command-and-control policy that is simpler and more familiar to most Oregonians. This is the regulatory policy of ramp metering of freeways in Oregon to relieve congestion. This, too, is a quantitative regulation because the number of vehicles allowed to join the freeway is controlled administratively (by a stoplight and enforcement scheme).

A market-oriented means of achieving the same congestion relief, by comparison, would be to charge a toll for joining a congested freeway. What is the difference? With ramp metering, the time that drivers spend every day waiting on the ramp for permission to proceed is a valuable economic resource that is lost *forever*. In contrast, the funds collected by the toll system used to ration use do not disappear, and can be used to offset any adverse effects on those tolled off of the freeway. There is no, or very little, dead-weight resource losses with a price-based system.

Implementation of the LCFS cannot avoid creating huge, dead-weight resource losses. Indeed, Holland et al (2007)[2] demonstrated that deadweight losses dominate the value of carbon reductions by as much as a factor of 20 times even at high implicit costs of atmospheric carbon dioxide. Just as importantly, however, Holland et al. demonstrated that there is a chance that the LCFS will actually increase, rather than decrease, carbon emissions. In summary, LCFS (1) may or may not even achieve its stated emissions goals, and (2) with near certainty will do so at far greater economic resource cost than would be borne with no policy at all.

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[1] Randall J. Pozdena, PhD, "Oregon's Proposed Low-Carbon Fuel Standard: The Economic Impacts," Oregon House Committee on Energy, Environment and Water, May 24, 2011.

[2] Stephen P. Holland, Christopher R. Knittel, and Jonathan Hughes, "Greenhouse Gas Reductions under Low Carbon Fuel Standards?" NBER Working Paper No. 13266, first issued in July 2007.

Why do we continue to rely on clumsy, wasteful, and often counter-productive command-and-control systems? The LCFS, for example, could be implemented with a carbon content price levy and rebate system instead. It may be a cynical view, but it is my opinion that the very complexity of the economy and the difficulty of accounting for dead-weight losses is what makes administrative interventions possible. The ability of regulators to conceal or misrepresent the costs of regulatory actions may be why policy makers prefer them to price mechanisms, which have the nasty characteristic of making their costs very apparent to constituents.

Continuing with the ramp metering example, the huge time resource losses are intangible and measured and reported by no one. In contrast, the value of toll charges and their disposition would be front-page news. Put differently, it may be the case that bad policies, like bad people, seek the cover of darkness.

Another reason for policy maker preferences for standards versus a cost-based carbon levy is that policy makers may wish to implement a standard that is more aggressive than the economics justifies. For example, levying a charge equal to estimates of the economic damage of carbon emissions between $30 and $100 per ton–the latter a number at the upper end of professional estimates–would raise the fuel costs of driving by one to three cents cents per vehicle mile, versus the current 13 cents per mile.[3] This is not a trivial increase, but perhaps not enough to satisfy the carbon-reduction and technology-forcing daydreams of some regulators or policy makers.

This underscores further the folly of LCFS-style approaches: they can more easily be disconnected from reality because there is no clear means of measuring the damage done by pushing a non-economic standard too hard in the marketplace. If Oregon is truly serious about dealing with carbon emissions in a way that balances carbon costs and benefits transparently to the citizenry, it would scrap the LCFS and advocate for a revenue-neutral carbon content levy instead, and let it be debated with the benefit of transparency.

OFF-RAMPS AND OTHER UNCERTAINTIES

Nothing illustrates the hazards and challenges of the regulatory approach better than the so-called off-ramp or deferral features of the proposed regulations. These features are supposed to provide a safety valve that would relax or suspend the LCFS if it yielded onerous burdens on the economy–because of large fuel price increases, failure of biofuel supply to materialize, etc. As mentioned earlier, the very fact that this feature is needed to advance the policy reveals the opaque, crap-shoot nature of the LCFS.

Even if one puts that concern aside, the complexity of the implementation of this one, small part of the LCFS bureaucratic process reveals how absurd it is to expect a system of committees and regulatory staff to measure, let alone respond to, degenerate outcomes from the LCFS. It requires complex measurement techniques to calculate the price trends

[3] Assuming 30 mpg vehicle fuel consumption.

that would have occurred in absence of the policy, and even more complicated to perform the timely, clear and sophisticated analysis needed to craft a truly beneficial response.

As I understand it, the LCFS off-ramp is triggered by certain events, to be followed by certain accommodations by the Environmental Quality Commission. However, there are definitional, measurement, and regulatory discretion issues that cloud the the way the market will respond to the triggered actions:

- Changes in LCFS implementation can be triggered by biofuel supply or price level breaches. In neither case is it obvious how the breaches will be measured or how the inherent high volatility of both quantities will be accommodated.
- Since many factors can affect biofuel supply or price, it is not clear how events can or will be causally attributed to LCFS.
- The off-ramp policy grants wide administrative discretion in declaring a breach, and the actions to be taken in response, creating further uncertainty and risk.
- There is no mechanism for requiring the actions taken to be cost-effective nor a stated, quantifiable outcome that the market can count on in planning its participation in the LCFS.

These are the kind of subtle and complex issues that belong in dissertation research, not a live, real-time regulatory process. Implementation of this policy will prove to be so difficult, contentious, and capricious that the marketplace will have difficulty anticipating how the implementation of LCFS will actually play out. The result is that the private sector agents who supply and use fuel will face uncertainty and financial risk. As every first-course finance student knows, uncertainty is itself tantamount to a cost that cannot be avoided. It is either borne directly, or addressed by expensive defensive hedges or insurance, costly maintenance of multiple processes, or special procedures and contractual terms. Even if policy responses could be counted on to be good on average, the uncertainty will hobble markets.

THE COST OF UNCERTAINTY IN A SMALL STATE

All of these considerations suggest there will be real economic burdens on the suppliers and users of affected fuels, especially in Oregon. In the normal workings of the private market for fuel, participants must forecast a few key parameters, such as prices and demand. Insertion of a new, complex regulatory response variable into this dimension of the private market means that participants must now also forecast the behavior of the regulator and its impact on the normal factors of interest. This changes the production, consumption and investment decision making complexity of private participants by an order of magnitude.

In such an environment, the private sector will be forced to bear losses in the value of existing assets that may (or may not) be stranded by the change in regulation. In addition, new investments needed to accommodate the policy will be subject to higher hurdle rates to reflect the risk of those investments being stranded.

The off-ramp uncertainty is compounded in the biofuels context by the fact that, under the most generous assumptions about biofuel technology and availability, the Oregon industry will be small relative to the overall biofuel market. This puts the Oregon industry at the mercy of regulatory whims and market conditions originating elsewhere. The Oregon supply of biofuels will be whipsawed significantly by even the normal variability in prices upstream of their production.

A good example of this is provided by the actual behavior of the corn ethanol market. The relative variance of returns received by ethanol refiners is twice that of the larger volume petroleum sector, and the volatility of returns received by suppliers of the corn feed stock are ten times that of the ethanol refiners, as documented recently by Trujillo-Barrera, et al. (2011).[4] This is a natural consequence of the fact that small firms' economic fortunes are naturally more variable than they are for large firms, and suppliers fortunes more variable than the larger firms they supply.[5] The point is that the LCFS process inserts tremendous uncertainty into markets that are already prone to highly uncertain returns.

These uncertainties that arise in the product market are amplified still further by the vagueness and latitude of the policy response by the regulator that is allowed under the proposal. One does not know with certainty when, why or for how long responses will be triggered, nor what the response will be and for how long the accommodation will last. The uncertainties faced by some market participants will make winning the lottery seem a sure thing by comparison.

Bear in mind that the off-ramp policy is but one dimension of the complex thicket of regulations and procedures that constitute the LCFS proposal. The level of bureaucratic adroitness required to respond benevolently under these conditions is simply unrealistic. In my view, the initiative as a whole is naive, and toxic to the economic interests of fuel market participants and the economy of the state.

NO JOBS BONANZA

This testimony has concentrated on my view that the LCFS will generate far more collateral economic damage than economic or environmental good. However, it also is worth restating my opinion that I also believe that there are no realistic prospects of collateral *benefit*. In its defense of the LCFS, DEQ and its consultants advanced the notion that jobs will be created by implementation of the LCFS. There is no doubt that this would be useful at this time when our economy continues to languish.

Unfortunately, it is unreasonable to expect a policy like the LCFS to generate jobs. From a purely theoretical standpoint, disturbing an economy that is in equilibrium with a massive intervention into a key input market is bound inexorably to depress current output and

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[4] Trujillo-Barrera, A., M. Mallory, and P. Garcia. 2011. "Volatility Spillovers in the U.S. Crude Oil, Corn, and Ethanol Markets." Proceedings of the NCCC-134 Conference on Applied Commodity Price Analysis, Forecasting, and Market Risk Management. St. Louis, MO. [http://www.farmdoc.illinois.edu/nccc134].

[5] Roger G. Ibbotson, Paul D. Kaplan, and James D. Peterson,1995 "Estimates of Small Stock Betas are Much Too Low".

employment. Indeed, if reduced carbon fuel content were productivity- and profit-enhancing, low carbon fuels would be dominant in the marketplace without intervention. Hence, one cannot reasonably expect regulations that require altering current fuel content to create more jobs than exist today–jobs will be lost instead. (That is why I was not surprised by the failure of the Keynesian stimulus policies at the national level, either.) The market is too complicated to emulate by statute or administrative procedure. As I testified earlier, I believe the forecast of net new job creation to be an artifact of the use of models that misrepresent the way the economy works and are predisposed to predict creation of jobs from government interventions.

Nor can Oregon expect to influence the pace of technological change to a significant degree ("technology-forcing"). Although some take pride in Oregon's tendency to step out ahead of market acceptance of wind, solar, biofuel and other technologies, the fact remains that mandated or subsidized technology forcing has a bad economic performance track record, as I revealed in prior testimony.

This applies perforce to the LCFS, because of Oregon's small market size, and its lack of an indigenous petroleum production or refining industry. In effect, Oregon has to bear a transportation premium in obtaining fuels because it is at "the end of the line" of the motor fuels supply process, and a relatively unimportant client of the many firms that constitute the supply chain of fuel in Oregon. The incentive for any one firm to accommodate itself to an exotic and uncertain LCFS policy in Oregon is, thus, small. This means that Oregon very likely will be the victim of variable and costly supplies and prices of compliant fuels. If the application of LCFS in California functions as many economists predict, Oregon will suffer from the loss of refining capacity in that state and the attendant increase in fuel prices.[6] Higher fuel prices, in turn, will cost Oregon jobs.

Thus, contrary to the naive simulations that predicted LCFS to increase Oregon jobs, the LCFS–if implemented–will be a job killer. In addition to the theoretical logic, the empirical evidence is overwhelmingly in favor of this conclusion. The forced ventures into energy technologies not embraced by the market has been shown to dissipate, rather than create new jobs–each new "green" job costs several jobs elsewhere. The adverse effect of mandates is difficult to measure and thus easy to mask (per our earlier discussion). In the case of subsidies we know with certainty that funds are diverted from uses that the market values to ones that it does not, necessarily reducing economic output and jobs.

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[6] For example, a study by the Boston Consulting Group (BCG) concludes that implementation of that state's LCFS would result in the closure of 20 to 30& of California's refiner capacity, the loss of 28,000-51,000 jobs from refinery closures alone, and cost recovery (per gallon of remaining output) of 1 to almost 3 dollars per gallon. Boston Consulting Group, "Impact of AB 32: Summary of key findings," June 18, 2012. Retrieved from http://www.cafuelfacts.com/wp-content/uploads/2012/07/BCG-Report-Summary.pdf

INTERNATIONAL

October 21, 2010

Critique of Oregon's LCFS
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Charles River Associates was retained by WSPA to perform a critical review of the scenarios and analysis performed by Oregon's DEQ's consultants in their economic analysis of a Low Carbon Fuel Standard for the Oregon. All opinions, analyses and conclusions contained herein are the authors'.

We appreciate the opportunity to comment on Oregon's economic analysis of its proposed low carbon fuel standard (LCFS). The modeling team in Charles River Associates' Climate and Sustainability Practice has had extensive experience in building and using energy-economy models for the analysis of climate policies, including several recent studies of Low Carbon Fuel Standards (LCFS).

- As part of a study for National Mining Association of the Lieberman-Warner Bill (S.2191), CRA analyzed a nationwide LCFS proposal to reduce emissions by 10% by the year 2020.
- As part of a study on AB 32 requested by California ARB, CRA assessed the cost of California's LCFS program and compared costs under different assumptions about the availability and costs of alternative transportation fuels (http://www.crai.com/uploadedFiles/analysis-of-ab32-scoping-plan.pdf).
- For Consumer Energy Alliance, CRA assessed the economic impacts of a Federal LCFS (http://consumerenergyalliance.org/wp/wp-content/uploads/2010/06/CRA-LCFS-Final-Report-June-14-2010.pdf).
- Most recently, CRA submitted comments on NESCAUM's proposed LCFS study.

The state of Oregon faces many of the same issues and challenges that we did in our studies and that NESCAUM does. The many basic uncertainties about new fuels technology and life cycle analysis of emissions compelled CRA to develop high and low cost scenarios. CRA, though, was able to use a single, integrated energy-economy model, but Oregon must also cope with the added complexity of having to reconcile a transportation sector model with a separate, and not necessarily consistent, regional economic model. Our comments, therefore, are based on actual experience in conducting comparable studies.

The major points of our review are:

- The modeling approach is critically flawed. Because VISION and REMI models are not internally consistent, as a result the models' reported economic impacts of the LCFS are erroneous and misleading;
  - Model results must be incorrect in showing an economic gain, to the extent that outcome arises from a reference case in which motorists and fuel producers are characterized as acting irrationally and sub-optimally.
  - Model methodology accounts for investment decisions incorrectly.
- The scenarios do not incorporate a wide enough range of uncertainty;
  - The scenarios assume many of the key conclusions, rather than allowing the analysis to determine them;
  - The scenarios fail to reflect large uncertainties in key variables, based upon prior LCFS analyses conducted by CRA. For example the cost and availability of cellulosic ethanol is quite speculative at this point; therefore sensitivity analysis should be performed to reflect this large uncertainty;
  - Policy off-ramps would reduce the possible negative impacts of the LCFS policy, but they would not eliminate them. There would still be sunk costs, such as those incurred with long-term contracts for Brazilian ethanol, from activities undertaken to comply with the LCFS program.
- The analysis ignores the significant costs of implementing an LCFS in the construction of their reference cases;
- Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol facilities will be constructed;
- Incorrect economic indicators of economic wellbeing are used. Gross State Product (GSP) can be a misleading indicator of overall well being of state residents, as can employment changes and consumer expenditures.

Because of the limited amount of time allocated to us to review the economic assumptions and results of the economic analysis, we have identified a number of issues which we have not had sufficient time to thoroughly investigate. As a result, we have included some questions at the end that voice our concerns about how the analysis was conducted.

Flaws with Modeling Approach

The modeling approach used that combines the VISION and REMI models is fundamentally flawed. The VISION model fails to optimize consumer choices and, therefore, modelers determine the vehicle choices in the baseline and the scenarios. If the modelers are not careful, they can add a policy that allows consumers' fewer choices but then appears to make consumers better off than they were in the unconstrained baseline. This appears to be the situation in the state's analysis: when the modelers apply the LCFS policy, they find economic gains in all scenarios except one.

This modeling structure suffers from the additional problem that the REMI model fails to capture losses in consumer welfare and account for the full impact of investment decisions. For example if a policy leads to higher delivery costs for goods and services because the policy brings about an increase in the price for truck fuel, then this will translate into higher prices for goods and services so consumers will be unable to purchase the amount of goods they could have in the absence of the policy. This lower level of consumption is a true loss in consumers' wellbeing. That is, consumers no longer achieve the level of consumption that they would have had without the policy. The REMI model fails to capture this economic loss and therefore the results are biased upward.

Scenarios A through G report positive economic impacts because investment comes into Oregon from outside the state, but there is no discussion or justification why firms would choose to invest in Oregon rather than produce fuels where it is most economic to do so. In fact if recent investment patterns are any predictor of future investment decision, ethanol producers are likely to locate in Idaho and Washington. Allowing money to flow freely into Oregon naturally produces positive impacts because it fails to account for all the economic flows and interactions with other states. Assuming that an LCFS program will stimulate in-state renewable fuels production without targeted supplemental state subsidies (e.g., producer's tax credits, reduced state sales tax) seems to be inconsistent with recent history.

The modeling approach seems to be one in which the LCFS policy simply provides a target for the overall emissions rate of the vehicles fleets. But the decision on how to meet the target is determined exogenously by the modelers who define pathways that quantify the amount of fuel consumed by each fuel type and achieve the LCFS target. These pathways, however, could have been chosen for the baseline and should have been chosen since they are supposedly better for the economy even without an LCFS. Therefore, it seems one is left with two alternatives, either the analysis is not legitimate or these economically better pathways (i.e., the pathways that were chosen when the LCFS is imposed and produce higher values of GSP, employment, and personal income) were not chosen in the baseline because consumers are evaluating their options using different metrics, namely utility or welfare. If the latter case is true, this suggests that the modelers should be working with these metrics rather than GDP, employment, or personal income because utility and welfare reflect the true economic condition of state residents.

The results of the analysis suggest some obvious questions. If all these economic gains are possible from implementing an LCFS policy, then why is the market not undertaking these actions in the absence of any policy? According to the analysis, there seems to be a great deal of money to be made if companies began producing biofuels in Oregon and consumers began driving alternative fuel vehicles (especially electric vehicles from the results of scenario D). If the analysis suggests all these gains, why do regulators need to impose any policy because industry will see gains in output and consumers will naturally want to use these alternative fuel vehicles because they will see a rise in their personal income?

The measured economic gains to Oregon arise because entities outside the state are assumed to shift investment toward Oregon as a result of the LCFS. The study simply assumes the conclusion that fuels will be produced in Oregon, without investigating in any way whether Oregon has a comparative advantage in producing these fuels. NESCAUM also assumed that their own client, the Mid-Atlantic and Northeast states, would be the best places to produce low carbon fuels because of their concentration of high tech firms, and the State of Washington makes similar assumptions in five of the six LCFS scenarios it analyzed. Even if each state were correct that the least cost alternative is to produce locally, then the investment would have to come from within its own borders by displacing consumption and raising the cost of living. If all states were to implement their own LCFS policies in the expectation that they could improve their economy by attracting additional investment, they would all be proved wrong. Nationally, the only source of investment is either reduced consumption or increased borrowing from overseas – that must be paid pack in the future. Thus the conclusion is inevitable that the increased investment required to produce low carbon fuels, rather than conventional fuels, is overall a net cost to the U.S. economy. Since the Oregon LCFS is consciously part of a plan that would have many states adopt similar programs, it is inconsistent to assume that Oregon will stimulate its economy by attracting investment from other states that are not adopting similar programs. But then this leads to the conclusion that if all states implemented an LCFS, the additional constraint on economic choices would reduce profits and consumer welfare. The contrary conclusion of this study violates fundamental principles of economics as well as common sense. But this flawed result follows from the failure of the analysis to consider the full effect of investment decisions throughout the economy.

Furthermore, the scope of the modeling analysis is too limited. The LCFS policy affects other states since Oregon has trade with them, especially given Oregon's lack of refinery infrastructure. Therefore, the analysis should incorporate a broader regional coverage than simply just Oregon. Furthermore, the time horizon is too short. The LCFS policy is not scheduled to simply end in 2022. The continuation of the policy past 2022 has implications for decisions prior to 2022, but to capture this, the model needs to be run out a number of years past 2022 to understand the full effects of the LCFS policy in the near-term (2012 to 2022).

Range of uncertainty

We applaud the modeling teams for using values for carbon intensities, vehicle costs, and vehicle efficiency that fall in the middle of accepted ranges. During our research on the different LCFS proposals, however, it became clear to us that uncertainty surrounded many of the key input parameters. The unknowns greatly complicated the issue. Opinions differ regarding emission factors. They also differ about the cost and rate at which major new technologies would be commercialized and the availability of resources to support those technologies. Taken together these many unknowns lead us to conclude that any analysis used to inform decision makers should consider the range of outcomes for all key input parameters so that decision makers understand the possible range of outcomes from their proposed policy.

Therefore, instead of relying on one set of assumptions for vehicle cost, fuel cost, carbon emission intensities, and fuel economy, we urge the state to build optimistic and pessimistic scenarios that span an appropriate spectrum of possible outcomes. The former scenario should contain the most likely positive outcome for each key input parameter, and the latter one should contain the most likely negative outcomes. Only in this way can the analysis capture the full range of plausible outcomes.

Assuming the conclusions

Based upon CRA's research and analysis, we conclude that the set of scenarios in the Oregon study fail to capture the full range of plausible outcomes. Each scenario assumes that some combination of technologies will succeed. Nothing guarantees this outcome. In fact Oregon presents no case for assuming that it will happen. In effect, Oregon is *assuming* the key conclusion from the study, i.e. that technology forcing is a given. Assuming that alternative fuels (renewable fuels such as ethanol and biodiesel) and plug-in hybrid electric vehicles (PHEVs) will be in plentiful supply and less expensive than their petroleum counterparts invariably leads to the erroneous conclusion that the GHG emission reductions sought by the program can be accomplished without incurring substantial economic costs.

The state's analysis does not justify the view that the new technologies will appear at the cost, and time, with the characteristics assumed. Furthermore, there is no discussion of technology pathways, the adequacy of incentives from LCFS to promote R&D, nor the R&D breakthroughs that will result in technology commercialization. Time and again the economic literature has stressed the profound uncertainties of R&D outcomes,[1] but the analysis done for the state seems to pay little heed. Finally, the consequences from the failure of new technologies to emerge are ignored in the scenarios.

The interpretation of the "technology-forcing role of LCFS" appears to be the only justification for the assumption that technology outcomes will be whatever is required to make compliance with the LCFS possible at negligible cost. Nothing is adduced to suggest that these mandates, by one state, will have the characteristics needed to force technology to improve. In contrast, research that we have done would suggest otherwise.[2] Assuming that "technology forcing" advances in cellulosic ethanol and biodiesel technology will be achieved in a timely fashion to enable the volumes of low carbon fuels called for by the program are overly optimistic if other states and regions proceed with an LCFS. As of today, cellulosic fuel production technology remains essentially in the development phase, and wide scale PHEV application is unlikely in the absence of a significant distribution network.

From experience, there is clear evidence that the success of technology forcing is not a given. Rather there is clear evidence from other attempts to mandate technology, e.g., electric vehicle (EV) mandates in California, that show a number of unintended responses can occur. For instance, mandates that are perceived by developers as unachievable are ignored. Local or regional mandates are met in ways that are not consistent with the policy objective such as redirecting supplies or through leakage. Only mandates that hit a "sweet spot" involving a reachable goal that is not otherwise likely to be met can be successful. Finding

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[1] Kenneth J. Arrow "Economic Welfare and the Allocation of Resources for Invention" in *The Rate and Direction of Inventive Activity: Economic and Social Factors*; Richard Nelson (ed). Princeton, Princeton University Press, 1962. See also Richard R. Nelson, and Sidney G. Winter (1977). "In Search of Useful Theory of Innovation," *Research Policy*, 6(1): 36-76.

[2] Lane, Lee, David Montgomery, and Anne E. Smith (2009). "R&D Policy" in CEDA Growth No. 61, "A Taxing Debate: Climate Policy Beyond Copenhagen." Available at: [illegible]Dpolicy.pdf.

that spot requires careful analysis of current technology status and R&D activities, in order to aim successfully between overly ambitious specifications and specifications that will be met even without the program. Given the inherent uncertainties of R&D, there is no guarantee of success in this endeavor. Therefore, a basic premise upon which the scenarios are based is flawed.

In addition, Oregon should consider scenarios that allow demand destruction of VMT to reduce the required amount of new alternative fuel vehicle sales; and/or large costs for fuel and vehicle infrastructure to be incorporated to achieve the aimed for alternative fuel vehicle penetration levels. Currently, none of the Oregon scenarios investigates the possible risks of the mandates if none of the technologies turns out to be a silver bullet. Should that outcome occur, either the standards must be abandoned or modified, or if they are enforced as written in the scenarios the result will be to drive delivered fuel prices up to the point at which motor fuel demand (VMT) is driven down to a level consistent with available low carbon supplies. This fuel consumption and corresponding VMT reduction is more likely. Furthermore, the higher the carbon intensity of available fuels, the higher the quantity of new fuels required. This outcome cannot be fully represented in any of the models being proposed for use in the Oregon analysis, so that the costs of a failure scenario will never be assessed.

Sensitivity Analysis

Blend wall

For three scenarios (C, F, and G), Oregon assumes the blend wall can be increased to 15% by 2020. Breaking the blend wall has its own set of challenges. EPA have announced a partial waiver for MY2007 and newer vehicles after a protracted analysis period. Extension of this to MY2001-2006 remains under study and MY2000 and older and other vehicle classes/applications are not in view. These scenarios ignore the possibility that consumers will need to purchase the more expensive flexible fuel vehicles if newer non-flexible fuel vehicles or their existing vehicles are unable to burn E15. Furthermore, these scenarios assume that enough fueling stations will find it cost-effective to upgrade and be located in enough convenient locations to achieve the assumed sales.

ILUC

The analysis considers scenarios (specifically C, F, and G) that omit the emissions from indirect land-use changes (ILUC). This is an optimistic assumption and provides the biofuels for which the ILUC is omitted a large advantage.

Need for range of assumptions

The probability of the increasing ethanol content in gasoline to 15% and the value of ILUC should be studied thoroughly. The state is right to have considered optimistic assumptions regarding these two issues in its set of scenarios. But only assuming that biofuels do not result in indirect GHG land use change effects (ILUC) in several scenarios artificially biases these to favor biofuels thereby misleading decision makers on the accurate cost-benefit relationship that the wide scale introduction of these fuels entails. Indeed, the exclusion of ILUC fails to consider the overall GHG implications of biofuel feedstock choices, an omission which could negate the programs sought after GHG mitigation benefits. To be better balanced, the analysis should consider the less optimistic scenarios where the blend wall cannot be exceeded and low carbon fuel supplies do not materialize in large volumes possibly because of issues with ILUC. The clearest case is one in which there is only enough low carbon fuel of any kind that is useable by the fleet to achieve for example a 5% improvement in carbon intensity at reference case fuel consumption. Since the standard must still be met, the only alternative is reducing total fuel consumption, and this will be achieved because fuel suppliers will bid up the price of the constrained supply of low carbon fuels until the pump price rises high enough to choke off demand. This same outcome will occur if the low carbon technologies fail to appear, or new vehicles able to use them are not produced in sufficient numbers, or the refueling infrastructure required to support consumer adoption fails to materialize.

PHEV lifecycle vehicle costs

Using the assumptions for fuel efficiency, fuel costs, and incremental vehicle costs, it appears that applying a bit of sensitivity to the assumptions regarding PHEVs[3] results in these vehicles having higher life cycle costs than conventional gasoline powered vehicles. Given the cost differentials, consumers would not purchase PHEVs unless they were subsidized. The amount of subsidy needs to be accounted for as a cost and reflected in the life-time budget. If the life cycle cost of PHEVs exceeded that of gasoline powered vehicles, which is clearly quite plausible, the benefits of Scenario D from PHEVs would disappear and become a cost to consumers from forcing them to purchase more expensive vehicles. As regulators have stated, they would suspend or shut down the program if costs rose too much. But there would still be some economic damage, especially in terms of sunk costs such as long-term ethanol contracts with Brazil, that would result from agents attempting to comply with the LCFS. We are advocating for a scenario to be analyzed the incorporates this very real possibility.

Reference Case

The Oregon analysis assumes full implementation of an RFS2 program by EPA. However, EPA is currently reviewing the specifications of the program in light of the lack of investment in capacity to produce advanced biofuels.[4] The EPA has delayed its decision until year's end.

There is also uncertainty in the minds of investors which brings in doubt about the success of these other policies. For example, investors are wary of the government's resolve to continue fuel subsidies for various biofuels. Congress has already allowed the subsidy for biodiesel to lapse, which has resulted in the

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[3] Assuming an efficiency of gasoline vehicle of 35 mpg, EER of 3 for PHEVs, and VMT of 10,000/yr in electric mode (that is 2/3 of VMT in electricity mode) results in gasoline vehicles having a couple thousand dollar lower full life cycle cost assuming a 3% discount rate. Raising the discount rate to 5%, a more accepted number, results in an even greater cost advantage for gasoline powered vehicles.

[4] Facilities are expected to turn out up to 25.5 million gallons this year of cellulosic ethanol—far below the 250 million gallons that the U.S. Environmental Protection Agency (EPA) once wanted fuel makers to produce.

shutdown of existing biodiesel capacity. The subsidy for ethanol will also be up for renewal. Investors are wary of investing in biofuel projects whose success is dependent upon government subsidies when government actions have sent conflicting signals. Ignoring the risks associated with the availability of these biofuels by assuming that these fuels are readily available to meet the policies assumed in the reference cases as well as a regional LCFS policy again understates the uncertainty and costs of an LCFS policy. At least some of the scenarios examined should reflect an outcome where base case policies are not fully successful.

E85 Fuel Prices too low

The blend of E85 used in the EIA forecast likely contains little cellulosic ethanol. Therefore, if one were to account for the cellulosic ethanol used in the different scenarios, the cost of E85 would exceed gasoline. Therefore, the assumed price for E85 appears too low relative to gasoline.

Having said this, we recognize that the future price of ethanol is quite uncertain. Cellulosic ethanol is still undergoing process development, thus the costs to produce this biofuel are dependent upon the degree, the pace of technology improvement, and the success of commercial scale up. Also, the cost to produce lower emitting blends of ethanol involving conventional crops is also uncertain. Therefore, it is only reasonable that a sensitivity analysis should be performed that considers a wide range of prices for cellulosic E85 and conventional E85.

Failing to consider scenarios using a range of ethanol prices also leads to a lack of sensitivity in VMT values. By assuming the cost of ethanol is the same as gasoline on a gasoline gallon equivalent basis implies that the VMT will be virtually invariant between the scenarios and the baseline because the equation to adjust VMT, which relies on the percent change in fuel prices, will result in no adjustment.

Location of new ethanol plants

Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol production facilities will be constructed. In seven of the eight scenarios, the state assumes all new ethanol production facilities needed to meet the state's LCFS would be built in Oregon. With major production facilities recently built in Idaho and Washington, it seems that the probability of these facilities being expanded and new facilities being built outside the state rather than inside is much greater than one in eight.

Carbon Intensity Factors

The choice of values for emission factors can significantly affect the results of the analysis, and many uncertainties arise in selecting the right values to use. With biofuels, the life-cycle emissions of individual biofuels include both direct and indirect impacts. Determining direct emission can be challenging. Furthermore, accurately determining the indirect effects is highly uncertain and a subject for future research. As a result, the range of potential emission factors for a given biofuel can be quite large. Evidence of this is cellulosic ethanol and the range of estimates provided by EPA. Scenario design needs to recognize this uncertainty in the construction of the scenarios and allow for realistic optimistic and pessimistic scenarios.

Scenario D implies extremely high PHEV penetration

Scenario D seems to assume an unrealistic level of penetration of PHEVs. We built a spreadsheet model to estimate the penetration rate of PHEVs in terms of share of new vehicles sales in 2022. This vehicle turnover model estimates the size of the vehicle stock in each year by starting with the vehicle stock in the previous year and adding to this value new vehicle sales and subtracting off vehicle retirements.

To compute the penetration rates, we assume the scrappage rate and growth rate of the stock of vehicles is time invariant.

We adjusted the vehicle penetration rate of PHEVs over time to hit the Scenario D target for the stock of PHEVs in 2022. The growth and scrappage rates combine to determine the evolution of the vehicle stock. For the penetration rate, we attempt to represent the classic s-shaped curve while also inputting realistic ramp rates where possible. This would require that over 30% of new vehicles sold in Oregon in 2022 are PHEVs. This incredible penetration rate in terms of new vehicle sales would exceed all historical penetration rates for new vehicle technologies.

Scenario D suffers from an additional problem. The amount of change in the electric sector infrastructure to handle the great number of electric vehicles would likely be technologically infeasible without large costs. A study produced for the ISO/RTO Council in conjunction with Taratec suggests that a total of 1.5 million plug-in electric vehicles **nationwide** would be feasible in 2019 and 2.25 million would be optimistic. Scenario D suggests that Oregon would account for about 10% of new PHEV sales; whereas Oregon currently accounts for about 1% of all new vehicle sales.[5]

The highly questionable feasibility of the PHEV assumption for scenario D suggests that scenario should be modified to consider a much lower penetration of PHEVs.

Questions:

Are the price increases in food and food products due to competition between food and fuel production through agricultural production captured?

The cost of living will increase as ethanol production drives up the demand for agricultural products in Oregon. This will put pressure on food prices as well. The labor and capital cost would also increase and these increases will translate into higher production costs in Oregon. Are all these effects captured in the modeling?

Furthermore, assuming the price of imports from other states remains constant, Oregon would import more, which will offset the increase in GSP through a reduction in net exports or an increase in net imports. Is this effect captured?

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[5] "Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems." ISO/RTO Council and Taratec, (2010).

In the reference case, it appears that ethanol and gasoline prices are basically the same on a gasoline gallons equivalent basis. Since the incremental cost of flexible fuel vehicles is between $275 and $450 more than gasoline powered vehicles,[6] is there not a loss in consumer welfare because now consumers must pay more for each mile travelled? Does this loss show up in the calculations of personal income or any of the other economic measures? If not, then the analysis is not accounting for all costs?

Comparing the fuel price tables in Lawrence's October 19th memo, we do not understand why biodiesel prices are correlated with diesel prices, but E85 prices are not correlated with gasoline prices. Is there a reason for this difference in correlation patterns?

We could not find any discussion as to what entities provided the investment for the new commercial infrastructure (e.g., upgrades to petroleum terminals, delivery system for E85, new ethanol plants, charging and CNG stations, etc.) required for alternative fuels and vehicles. Who funds these new infrastructure projects? Also, what activities are forgone so that these new investments can take place (i.e., which sectors suffer losses because investment is being diverted to alternative fuel infrastructure)?

Where are the costs and resource requirements of implementing an LCFS program, such as rigorous compliance monitoring and enforcement by Oregon state agencies, factored into the analysis? Without focus on compliance and monitoring the outcomes of the program will be unknown and the overall benefit of the effort unclear, if in fact, achieved.

The description of Business–as-Usual notes a biodiesel blend level of 13.5% in 2022 due to the federal RFS-2, and this is used in modeling to effectively reduce the amount of biodiesel needed in the LCFS scenarios. Given that equipment and engine manufacturers do not endorse the use of higher than B5 and rarely, B10, this level of biodiesel use represents technology challenges for equipment manufacturers and warranty concerns for the predominantly heavy duty diesel fleet. Has forward looking acceptance of B13.5 been indicated by key global OEMs (original equipment manufacturers)?

The chart depicting the biofuel volumes used in compliance scenarios in 2022 (DEQ website, Oct 14th meeting files) prompts a number of questions:

- The BAU, BAU High Oil Prices and BAU Low Oil Prices differ only in the displacement of Sugar Cane Ethanol with Wheat Straw Ethanol; all other volumes of corn ethanol, cellulosic etc remain unchanged. This doesn't seem logical as higher oil prices would be expected to promote increased cellulosic production due to enhanced profitability of this new sector.
- Scenario C, F and G – Mixed biofuels without ILUC, without ILUC High Oil prices and without ILUC Low Oil prices also have identical fuel compositions in these scenarios. The impact of oil pricing on increased cellulosic production is not included.

[6] Wind, Cory-Ann, Memo on "Incremental Vehicle Costs," October 19, 2010.

- Scenarios A-G have a fixed quantity of Oregon Waste Biomass Ethanol regardless of inclusion of ILUC or oil pricing, implying that this product will be a lower ethanol stream than Brazilian sugar cane ethanol under all scenarios. On what basis is this assumption made? What in-state economic tariffs or other structure will be in place to make Oregon Waste Biomass Ethanol the lowest cost option for compliance as these scenarios depict? The August 10th Compliance Scenario Analysis slide 27 notes an Oregon Waste Food supply of 1.5 MGY (Summit Natural Energy), yet the 2022 depiction has Oregon Waste Biomass Ethanol at close to 200 MGY, is this realistic?
- What pricing assumptions for sugar cane ethanol have made them such a low proportion of both BAU and scenarios despite their ready availability and carbon intensity benefits?

VMT Sensitivity to Fuel Prices

We are confused how the modeler's VMT sensitivity to fuel prices was applied. The October 19th memo from Michael F. Lawrence of Jack Faucett Associates (JFA) states: "The analysis of Oregon's low-carbon fuel standard pathways retained an elasticity formula already built into Vision. This elasticity formula assumes an elasticity factor of -0.1, meaning that a 1% change in the fuel price encountered results in a -0.1% change in VMT driven."[7]

Scenarios C, F, and G have very different fuel costs, but they consume exactly the same total volume of fuels as stated in table 29 of Jennifer Pont's October 18 memo.[8] Since this table's numbers are on a gasoline gallon equivalent basis, this equivalence implies that these scenarios have the same level of VMT. This result seems to directly contradict the claim that VMT was adjusted according to changes in fuel prices.

In Scenario G, which has the highest fuel prices relative to gasoline prices, presumably should have lower VMT than scenarios F and C. Is this true, and did the model account for the loss in consumer welfare from traveling less? My suspicion is that the model did not account for this loss. Furthermore, scenario G confounds the impacts of the prices by also lowering the carbon intensities for biofuels and allowing an increase in the blend wall. This reduction offsets the impact of the fuel prices so one cannot understand the full impact of gasoline prices being below biofuel prices.

Conclusions

The linking of the VISION and REMI models is not internally inconsistent. The REMI model fails to fully account for the economic impact of investment decisions. The flawed modeling approach means that the reported economic impacts of the LCFS are erroneous and misleading.

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7 Lawrence, Michael, "Memo: Basic Data Assumptions in Response to Requests Made at October 14 Meeting," October 19th, 2010.
8 Pont, Jennifer, "LCFS Scenarios Infrastructure Costs," October 18th, 2010.

The design of the baseline and scenarios biases the analysis and understates the costs of a regional LCFS policy. The design of the cases ignores a number of important issues and as a result assumes greater flexibility and lower costs to comply with an LCFS than actually exists.

The design of the scenarios creates the image that policymakers only need to decide between low cost biofuels and no additional cost electric vehicles on a life cycle basis. Important issues such as fuel infrastructure constraints (e.g., blend wall constraints on the use of biofuels and electricity grid upgrades), consumer resistance to purchasing new higher cost vehicles are washed away by the convenient choice of assumptions.

The true issue should be how much more of a GHG reduction benefit will such a program deliver over what is projected to be accomplished by federal and state programs already in place, and at what additional cost. The Federal RFS2 program will deliver GHG benefits federally, Oregon states concern that their fair share of the RFS2 will not be realized in state is an unrealistic basis on which to base an LCFS program of this complexity and cost, and the financial analysis provided fails to represent the true cost-benefit analysis on this basis.

Failing to present a realistic "worst case" economic scenario as part of this analysis only serves to reinforce the erroneous conclusions pointed out above.

Thus the Oregon study, as currently formulated, is not defensible as its results rest upon an inappropriate model structure and restricted set of input assumptions and scenarios. It will provide policymakers with a one sided and unrealistic view of the consequences of an LCFS policy.

BCG
ENERGY

Impact of AB 32
Summary of key findings

June 18, 2012

THE BOSTON CONSULTING GROUP

Impact on refining industry

- Energy efficiency projects will have a minimal impact on stationary refinery emissions.
- Demand reduction in the second compliance period (2015-17) shifts gasoline trade balances from Singapore imports to Mexico exports. This will likely result in closure of 4-6 refineries representing 20-30% of California's refining capacity.
- LCFS is unlikely to be fully implemented post 2015
  - Small number of Advanced Technology Vehicles, no commercially available cellulosic ethanol, and limited available quantities of low carbon intensity (CI) sugarcane ethanol
  - California refiners may opt to export fuels versus supplying the local market, potentially creating product shortages
  - A likely scenario is for cost recovery to exceed 250 cpg coupled with gasoline supply shortages as early as 2015.
- If LCFS is completely implemented beyond the second compliance period, this will result in the closure of an additional 1-2 refineries, representing 5-10% of California's refining capacity
- If LCFS regulation is changed abruptly after 2015, it will likely result in additional costs for refiners, consumers, and suppliers of alternative fuels.

Impact on California's economy

- Due to forecasted refinery closures California could lose 28,000-51,000 jobs, including many high-paying skilled manufacturing jobs, as well as indirect job losses due to multiplier effects.
- California could lose up to $4.4 Billion of tax revenue per year by 2020 resulting in further reduction in employment in certain areas (e.g., road maintenance, local businesses).
- There will be a wealth transfer of at least $3.7 Billion per year by 2020 from refineries and fuel suppliers to the California Air Resources Board as a result of purchasing allowances.
- As a result of AB 32 CA refiners will likely begin exporting very large quantities of gasoline, increasing stationary emissions above the level needed to supply the local market.
- Other negative impacts include loss of manufacturing expertise and increased cost of living resulting from higher fuels cost, disproportionately impact low income households.
- California's climate change regulations will discourage energy intensive industries from locating in the state, and existing industry will have an incentive to relocate outside of the state.
- AB32-related measures can achieve the goal of reducing GHG emissions in California to 1990 levels at a high cost, but will be at least partially offset by increased emissions outside of California from crude and bio-fuel shuffling.

Cost of compliance

- Based on carbon cost of $14/ton to $70/ton, we estimate the level of cost recovery required by the industry would likely be in the range of 49-183 cents per gallon (cpg) by 2020.
  - 14-69 cpg would be due to tailpipe emissions from transportation fuels being included under Cap and Trade
  - 2-8 cpg would result from stationary refinery emissions
  - 33-106 cpg (average 70 cpg) would be due to LCFS
- The cost of compliance could be much higher if the cost of carbon rises and becomes volatile, as electricity prices did in 2000
  - Additional 87 cpg (to a total of 270 cpg) in 2020 if Carbon price raises to $150/ton.
- The cost of LCFS compliance could be much higher as there is an inadequate supply of low CI bio-fuels to meet California's estimated demand or if more states adopt policies similar to California.

Key exhibit 1

Scenario if LCFS compliance is achieved solely through blending low CI blendstocks (e.g., sugarcane ethanol)

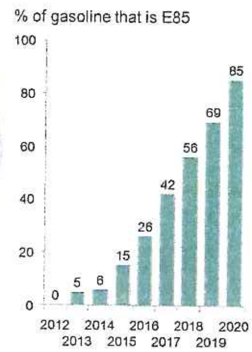
Model assumptions

No widespread adoption of low CI vehicles[1] by 2020, which would require:

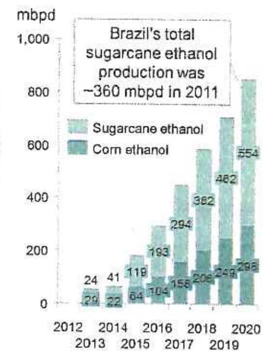
- Faster consumer uptake than historical hybrid uptake
- Significant technological advances
- Brand-new infrastructure network

Volume of sugarcane ethanol reaches 65% of total ethanol volume by 2014

LCFS targets will require majority E85 adoption



LCFS targets would require 554 mbpd of cane ethanol

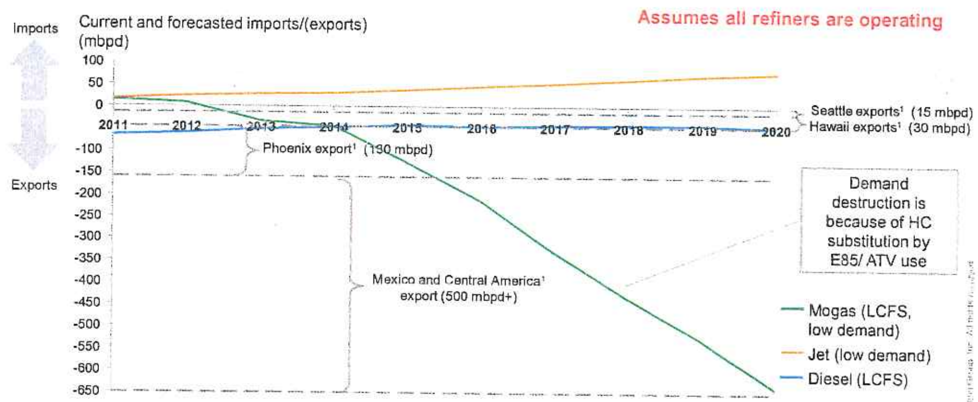


Projected ethanol adoption would also require rapid development of shipping and transport infrastructure

1. Powered by renewable electricity, low CI hydrogen, or CNG

Source: CARB, Bloomberg, BCG analysis, Renewable Fuels Association

Key exhibit 2



← 1st compliance period → ← 2nd compliance period → ← 3rd compliance period →

Net trade (mbpd)											Δ ('20-'11)
Mogas	13	7	(34)	(45)	(128)	(215)	(330)	(434)	(529)	(639)	(652)
Jet	15	22	26	30	36	45	52	61	70	78	63
Diesel	(67)	(62)	(53)	(48)	(43)	(46)	(45)	(42)	(42)	(46)	21

Import
Export

1. Based on current market conditions, which could change, but have not changed significantly historically;
High demand scenario also results in export by 2017 with LCFS

Source: CEC demand forecasts; BCG analysis

Key exhibit 3

1. Evaluate AB 32 impact on demand destruction for fuels (gasoline, diesel, jet)

- Determine impact of alternative vehicles
- Utilize ethanol blending to reach LCFS compliance
- Revise product demand forecasts

2. Establish supply/demand mechanisms & refinery economics

- Model operating and financial parameters of all PADD V refineries
- Create regional supply/demand matrix for potential mogas and diesel outlets
- Include impact of AB 32 compliance

3. Financially challenged refineries sequentially cease production

- Assume refineries with sufficiently negative cash flow would cease production
- Re-evaluate supply/ demand balance
- Determine new regional supply/demand balance

4. Determine PADD V refining capacity at equilibrium

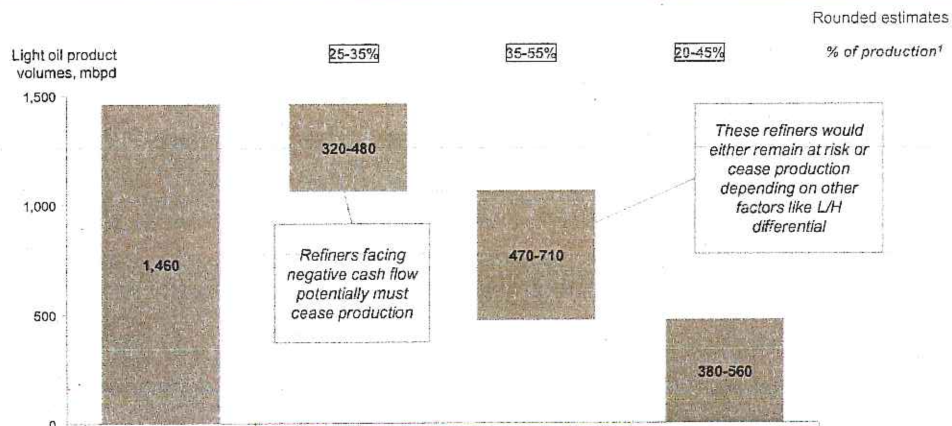
- Validate that refineries that have ceased production remain non-producing at new market equilibrium
- Construct new "industry health" matrix

5. Conduct sensitivity analyses to test breakpoints

- Use 2017 equilibrium posture as baseline
- Model impact of change in cost of carbon and narrow L/H differentials

wspa 3 pane summary.pptx THE BOSTON CONSULTING GROUP 6

Key exhibit 4

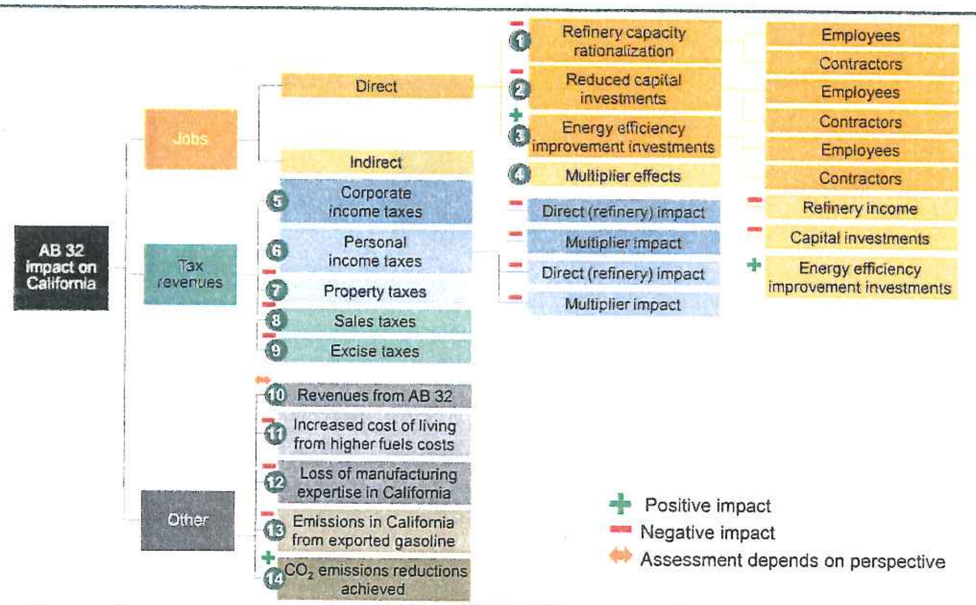


	Total	Distressed	May survive	Will survive
Crude capacity (MMBD)	2.0	0.5 – 0.7 (25 - 35%)	0.7 – 0.9 (35 - 45%)	0.5 – 0.7 (25 - 35%)
Number of CA refineries	14	5 - 7	4 - 6	2 - 4

1. Assuming 82% utilization for all refineries
Note: Assumes $110 crude cost and $25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

wspa 3 pane summary.pptx THE BOSTON CONSULTING GROUP 7

Key exhibit 5



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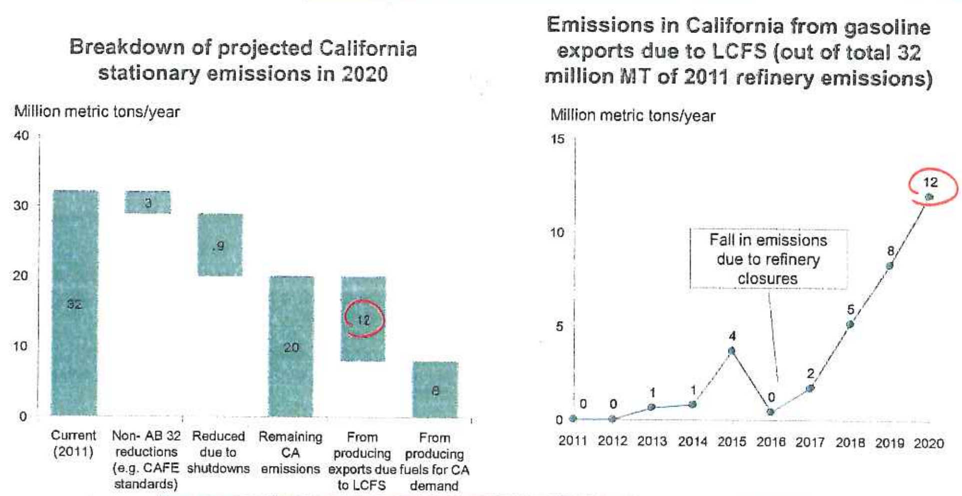
Key exhibit 6



Although tail pipe emissions are reduced, gasoline is still produced and exported; stationary emissions remain in CA

Source: CARB, CEC demand forecast, BCG analysis

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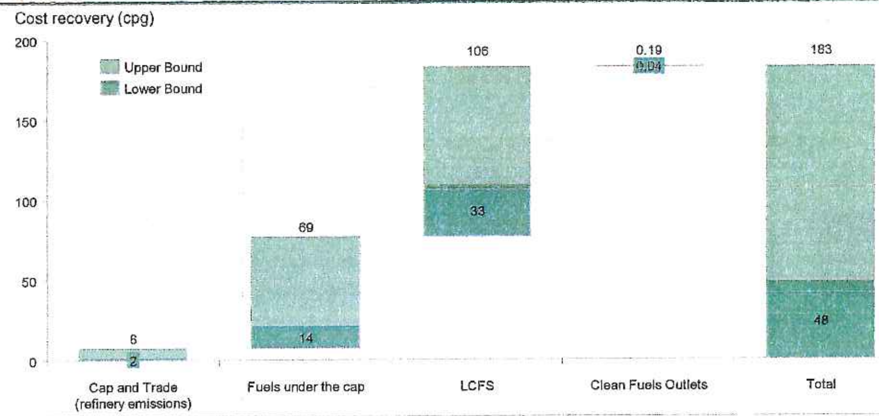
Key exhibit 7



	Cap and Trade (refinery emissions)	Fuels under the cap	LCFS	Clean Fuels Outlets	Total
Key assumptions	Refinery emissions constant through 2020 (include 5% efficiency improvement) Compliance achieved through CCA purchases CCA cost is \$14-\$70	Refinery output constant through 2020 Compliance achieved through CCA purchases CCA cost is \$14-\$70	Refinery output and CI constant through 2020 Additional cost due to substituting sugarcane E85 for gasoline Sugarcane price is USDA 2020 forecast +-20%	Only cost of capital recovery considered[3], WACC= 10% Investments made evenly starting in 2016, 20 year depreciation 100-450 outlets constructed at \$2MM each	**CCA costs set by general and reserve auctions, not open market (which could be higher)**

1. Includes diesel and gasoline
2 One LCFS credit is equal to one metric ton of CO_2e difference from prescribed values
3 Assumes minimal operating cost if colocated with gas station
"Source:"CARB,"Thomson Reuters, BCG analysis

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Key exhibit 8

Cost of LCFS compliance impact

In order to achieve sufficient levels of sugarcane ethanol, additional ethanol-specific investment would be needed in:

- Farming
- Distilling
- Shipping
- Terminals
- Distribution

The cost impact is most sensitive to the price of sugarcane. With a surge in demand, the price could spike/ be volatile, due to which our estimates are very conservative.

Based on the USDA 2020 forecast for the price of sugarcane with 20% variation above or below, the cost of compliance could be 33 -106 cpg

Key uncertainties

Is there sufficient sugarcane production capacity to meet rising global demand?

Can industry participants overcome local challenges (e.g., construction permits) to logistical and other required investments?

Will legal challenge to LCFS result in uncertainty that stifles new investment?

Can refineries and other covered entities persuade non-covered entities (e.g., gasoline retailers) to support LCFS mandates like CFO?

Is there a risk that distribution infrastructure gets fragmented across multiple fuel types resulting in fuels shortages?

Unclear if the optimal bio-fuel is sugarcane ethanol, cellulosic ethanol or some other technology.

Is there a risk of significant volatility, especially during the nascent stage of evolution of these markets?

Have robust market mechanics been fully thought through to avoid unintended consequences and market manipulation?

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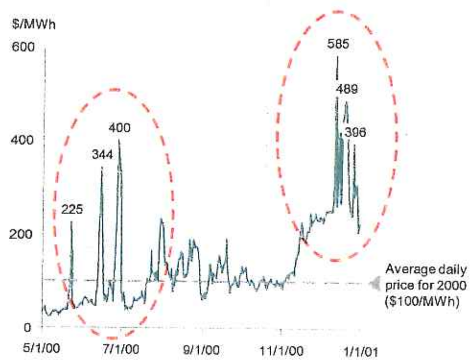
Key exhibit 9

California electricity prices (May – Dec 2000)



Cost of carbon could see similar volatility

Spikes in California electricity prices were caused by market uncertainty and speculation

As the carbon market develops, uncertainty will decrease; however, uncertainty will exist at the outset

Thomson Reuters has forecasted carbon prices of $30-35/ton; however, in order to account for a 4-5x spike in carbon prices, similar to electricity prices in the analog, we considered carbon costs of up to $150/ton as an unlikely but plausible scenario

Source: PowerDAT NP15 prices, BCG analysis, Thomson Reuters

BCG

THE BOSTON CONSULTING GROUP

Understanding the impact of AB 32

6/19/2012

This report is based entirely on publicly available information, CARB assumptions, and BCG's own experience and knowledge. BCG did not request nor receive any information from individual refiners. BCG utilized only its own analytical methods or those developed by the government or third parties. It did not rely on any similar or other analysis by any industry participant.

Table of Contents

1 Key findings

Impact on refining industry

- Given the small number of Advanced Technology Vehicles, no commercially available cellulosic ethanol, and limited available quantities of low carbon intensity (CI) sugarcane ethanol, LCFS is unlikely to be fully implementable by sometime in the second compliance period (*Key exhibits 1,2*). As a result, California refiners that risk being out of compliance, may opt to export fuels, versus supplying the local market, potentially creating product shortages. A likely scenario is for cost recovery to exceed 250 cpg coupled with gasoline supply shortages as early as 2015.
- If LCFS regulation is changed abruptly after 2015, it will likely result in additional costs for refiners, consumers, and suppliers of alternative fuels.
- LCFS driven demand reduction in the second compliance period (2015-17) shifts gasoline trade balances from Singapore imports to Mexico exports. This shift impacts refinery economics substantially and will likely result in closure of 4-6 refineries representing 20-30% of California's refining capacity.
- If LCFS is completely implemented beyond the second compliance period, this will result in the closure of an additional 1-2 refineries, representing 5-10% of California's refining capacity.
- While energy efficiency projects are one way to decrease carbon emissions, they will have a minimal impact on stationary refinery emissions, given that most California refineries are already highly energy efficient and the economics of such projects are not very attractive.

Impact on California's economy

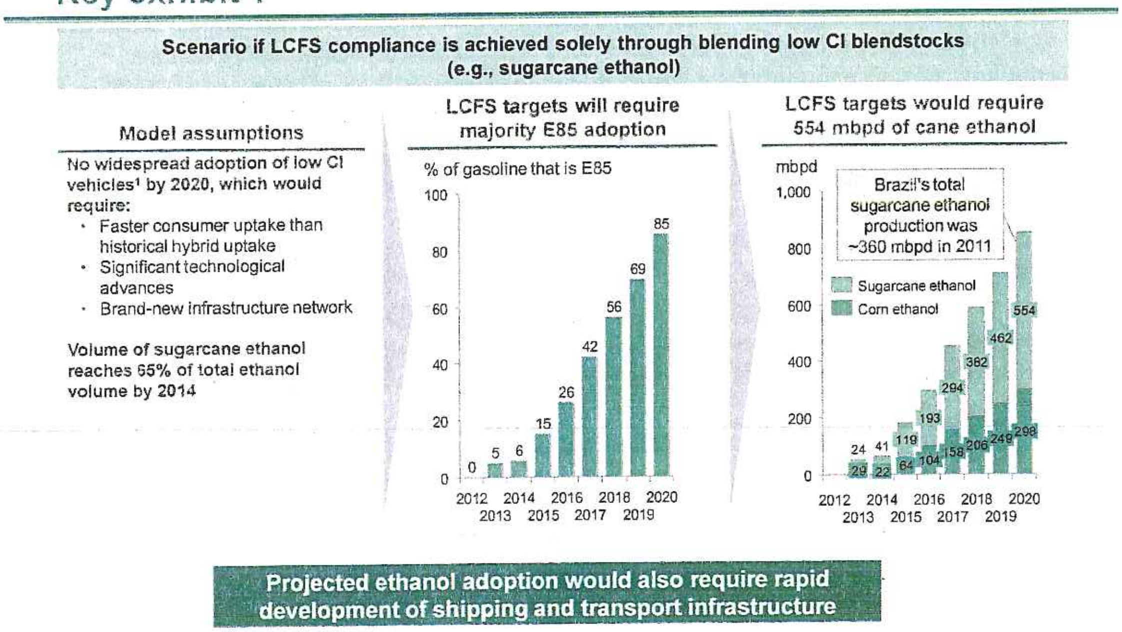
- As a result of forecasted refinery closures, largely resulting from full implementation of LCFS (*Key exhibits 3,4*), California could lose 28,000-51,000 jobs, including many high-paying skilled manufacturing jobs, as well as indirect job losses due to multiplier effects. This is net of 2,500 to 5,000 direct and indirect jobs created due to investments in energy efficiency.
- California could lose up to $4.4 Billion of tax revenue per year by 2020, the majority of which will come from lost excise taxes on fuels. This could result in further reduction in employment in certain areas (e.g., road maintenance, local businesses). Other revenue losses will come from decreases in personal income taxes, corporate taxes, property taxes, and sales taxes. These revenue sources will be lost permanently unless replaced by new taxes or other revenues (*Exhibit 5*).
- There will be a wealth transfer of at least $3.7 Billion per year by 2020 from refineries and fuel suppliers to the California Air Resources Board as a result of purchasing allowances. Minimum auction prices have been considered for this analysis and the cost could be much more with higher auction prices.
- As a result of AB 32 fuels related measures, California will likely begin to import diesel, increase imports of jet fuel, and begin exporting very large quantities of gasoline (*Key exhibit 2*). The GHG emissions associated with making gasoline for export will however remain in California (*Key exhibit 6*)
- California will suffer other negative impacts, including loss of manufacturing expertise and increased cost of living resulting from higher fuels cost.
- Increase in cost of compliance and the resulting cost recovery will disproportionately impact low income households that spend a greater share of their income on transportation fuels than high income households.
- California's climate change regulations (e.g. AB 32) will discourage energy intensive industries from locating in the state and existing industry will have an incentive to relocate to other states or even internationally.

- We assume that some combination of AB32-related measures can achieve the goal of reducing GHG emissions in California to 1990 levels, but at a high cost. In our view, these reductions will be at least partially offset by increased emissions outside of California from crude and bio-fuel shuffling.

Cost of compliance

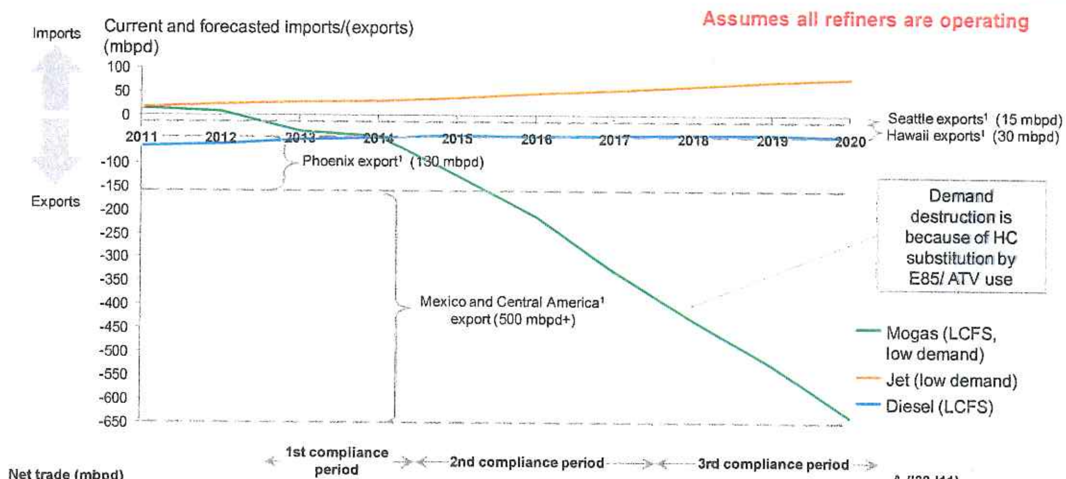
- Based on an assumed cost of carbon of $14/ton to $70/ton, we estimate that the level of cost recovery required by the industry to comply and meet California demand, should these regulations be fully implemented, would likely be in the range of 49-183 cents per gallon (cpg) by 2020. Of this, 14-69 cpg would be due to tailpipe emissions from transportation fuels being included under Cap and Trade; 2-8 cpg would result from stationary refinery emissions and 33-106 cpg (average 70 cpg) would be due to LCFS (*Key exhibits 7,8*).
- The cost of compliance could be much higher if the cost of carbon rises and becomes volatile, as electricity prices did in 2000 (*Key exhibit 9*). The estimated total cost of compliance would increase by an additional 87 cpg (to a total of 270 cpg) in 2020 if Carbon price raises to $150/ton.
- The cost of LCFS compliance could be much higher as there is an inadequate supply of low CI bio-fuels to meet California's estimated demand. If more states adopt policies similar to California, it will further exacerbate the situation by putting additional cost pressure on the limited available supplies of low CI bio-fuels.

Key exhibit 1



1. Powered by renewable electricity, low CI hydrogen, or CNG
Source: CARB, Bloomberg, BCG analysis, Renewable Fuels Association

Key exhibit 2

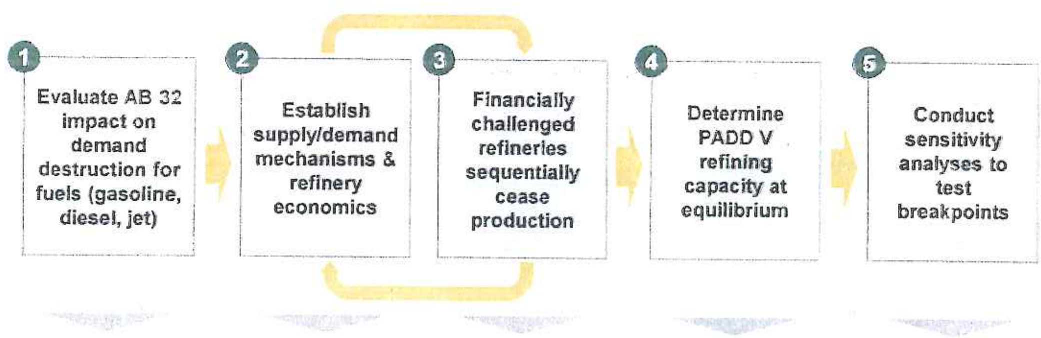


Net trade (mbpd)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Δ ('20-'11)
Mogas	13	7	(34)	(45)	(128)	(215)	(330)	(434)	(529)	(639)	(652)
Jet	15	22	28	30	36	45	52	61	70	78	63
Diesel	(67)	(62)	(53)	(48)	(43)	(46)	(45)	(42)	(42)	(46)	21

Import / Export

1. Based on current market conditions, which could change, but have not changed significantly historically; High demand scenario also results in export by 2017 with LCFS
Source: CEC demand forecasts; BCG analysis

Key exhibit 3



- Determine impact of alternative vehicles
- Utilize ethanol blending to reach LCFS compliance
- Revise product demand forecasts

- Model operating and financial parameters of all PADD V refineries
- Create regional supply/demand matrix for potential mogas and diesel outlets
- Include impact of AB 32 compliance

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- Model impact of change in cost of carbon and narrow L/H differentials

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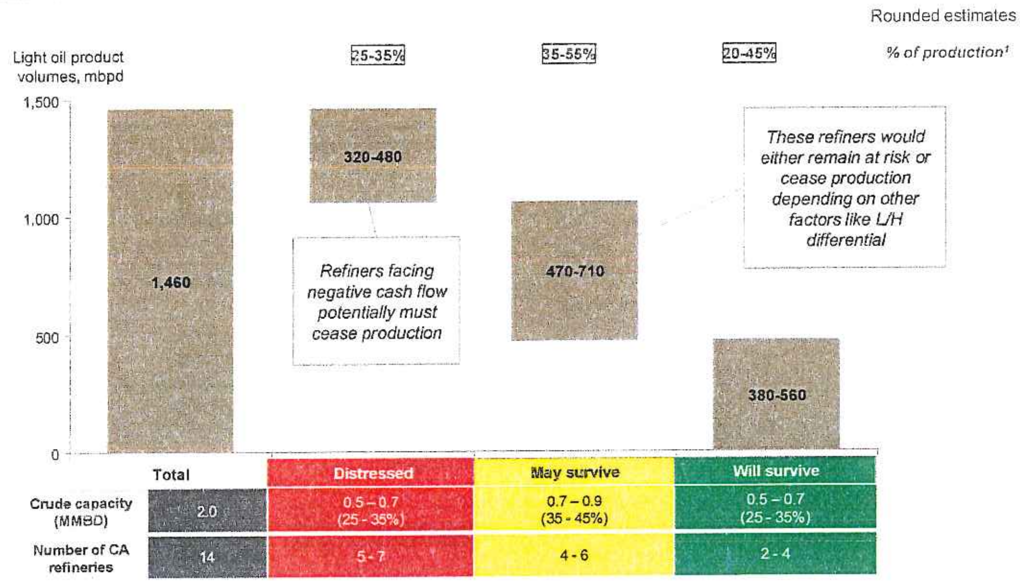
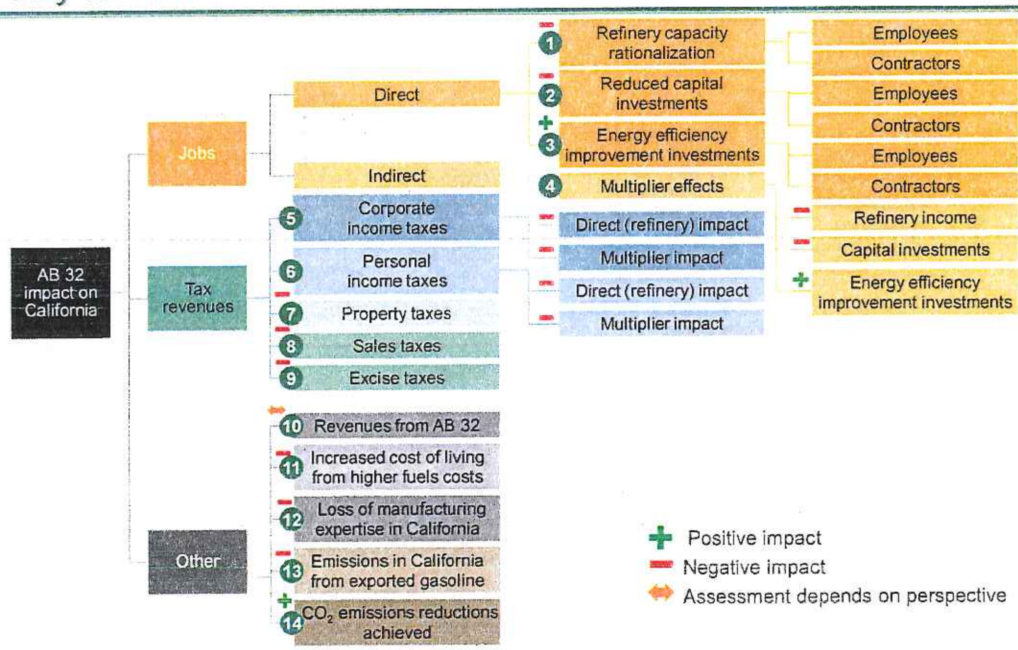
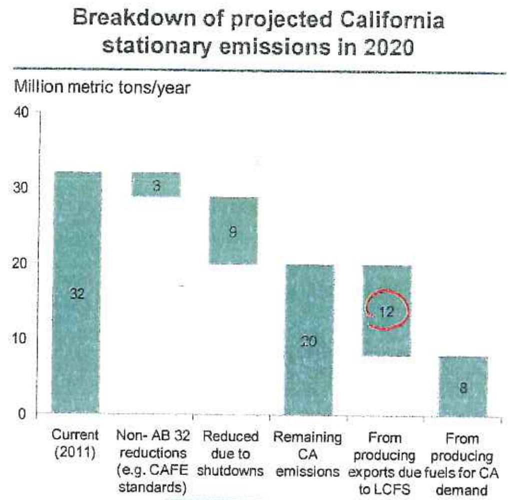


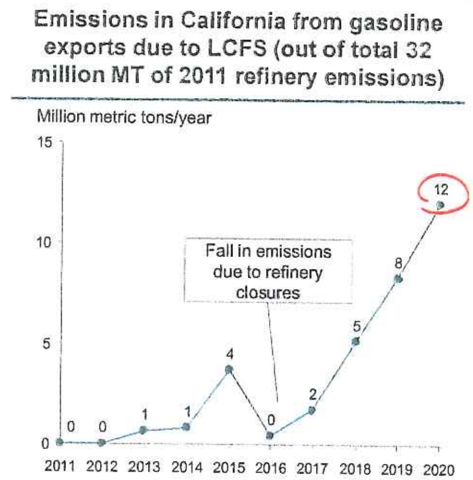
1. Assuming 82% utilization for all refineries
Note: Assumes $110 crude cost and $25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

Key exhibit 5



Key exhibit 6

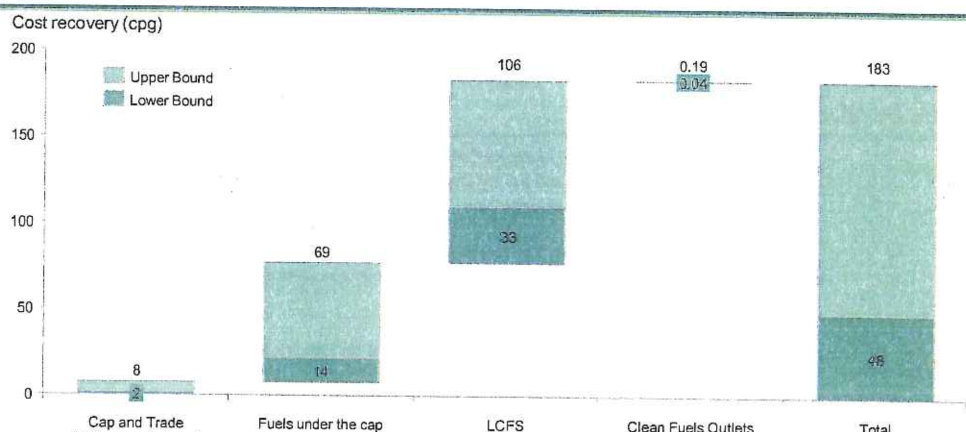




Although tail pipe emissions are reduced, gasoline is still produced and exported; stationary emissions remain in CA

Source: CARB, CEC demand forecast, BCG analysis

Key exhibit 7



	Cap and Trade (refinery emissions)	Fuels under the cap	LCFS	Clean Fuels Outlets	Total
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1. Includes diesel and gasoline
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3 Assumes minimal operating cost if colocated with gas station
Source: CARB, Thomson Reuters, BCG analysis

Key exhibit 8

Cost of LCFS compliance impact

In order to achieve sufficient levels of sugarcane ethanol, additional ethanol-specific investment would be needed in:

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- Distilling
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- Distribution

The cost impact is most sensitive to the price of sugarcane. With a surge in demand, the price could spike/ be volatile, due to which our estimates are very conservative.

Based on the USDA 2020 forecast for the price of sugarcane with 20% variation above or below, the cost of compliance could be 33 -106 cpg

Key uncertainties

Is there sufficient sugarcane production capacity to meet rising global demand?

Can industry participants overcome local challenges (e.g., construction permits) to logistical and other required investments?

Will legal challenge to LCFS result in uncertainty that stifles new investment?

Can refineries and other covered entities persuade non-covered entities (e.g., gasoline retailers) to support LCFS mandates like CFO?

Is there a risk that distribution infrastructure gets fragmented across multiple fuel types resulting in fuels shortages?

Unclear if the optimal bio-fuel is sugarcane ethanol, cellulosic ethanol or some other technology.

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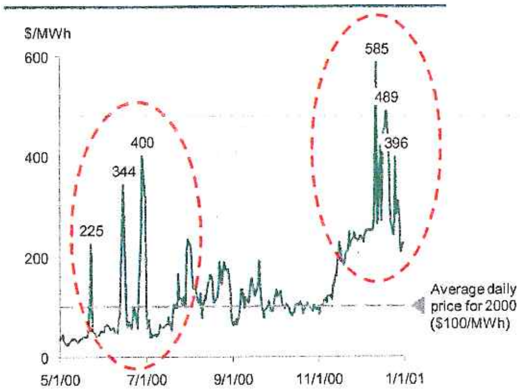
California electricity prices (May – Dec 2000)



Cost of carbon could see similar volatility

Spikes in California electricity prices were caused by market uncertainty and speculation

As the carbon market develops, uncertainty will decrease; however, uncertainty will exist at the outset

Thomson Reuters has forecasted carbon prices of $30-35/ton; however, in order to account for a 4-5x spike in carbon prices, similar to electricity prices in the analog, we considered carbon costs of up to $150/ton as an unlikely but plausible scenario

Source: PowerDAT NP15 prices, BCG analysis, Thomson Reuters

2 Executive summary

As part of California's climate change initiative the California Air Resources Board (CARB) is implementing a series of regulations, including a Cap and Trade program to put a price on carbon emissions, a Low Carbon Fuel Standard (LCFS) to reduce Carbon Intensity (CI) of fuels, a Clean Fuels Outlet (CFO) mandate to build hydrogen fueling outlets, and standards for car manufacturers to produce vehicles with lower or zero emissions. Collectively these regulations will significantly impact the oil refining industry in California.

There are 14 fuel refineries operating in California, with configurations ranging from simple to highly complex. These refineries produce approximately 834 thousand barrels of hydrocarbon gasoline, 340 thousand barrels of diesel, and 270 thousand barrels of jet fuel per day. Gasoline supply is approximately equal to demand, so imports and exports are minimal. Excess diesel is exported, and jet fuel is currently imported to meet demand. California's refineries collectively produce about 32 million tons of GHG emissions per year due to heating requirements, emissions from chemical process reactions, and electricity generation.

We analyzed the likely impact of AB 32 fuels policies on emissions and refining economics using proprietary BCG models. We then developed a framework to assess how these changes are likely to impact California's economy along key dimensions including employment, government revenues, and GHG emissions.

The most significant impact to refiners will come from LCFS, which as currently being implemented, is not viable. However, if you assume that LCFS will be fully implemented it will result in a substantial decline in demand for refined products, particularly gasoline. The likely result will be the loss of 20-30% of California's refining capacity in the second compliance period (2015-17) and 25-35% of California's refining capacity by 2020. This means 5-7 of California's 14 fuel refineries could cease production by 2020. Many of the remaining refineries in 2020 could become unprofitable if the economic environment worsens, potentially compromising California's security of fuels supply. Further, the regulation as currently being implemented could disrupt California's fuels supply if the likely scenario of infeasibility plays out, driven by slower adoption of new technologies (such as ATVs and cellulosic ethanol) than forecasted and insufficient supplies of sugarcane ethanol. Without adequate availability of LCFS credits and/or low carbon intensity (CI) bio-fuel blendstocks refiners will have no choice but to export increasing quantities of gasoline and reduce supply to the local market, potentially creating fuels shortages in California with far reaching consequences.

Even with adequate supplies of low CI bio-fuels we estimate cost of compliance with LCFS of between 33-106 cpg (average 70 cpg) by 2020 using current sugar cane price forecasts. The actual cost could be much higher if California's significant incremental demand increases the price of low CI bio-fuels. The situation could be further exacerbated as more states (e.g., Oregon) implement LCFS mandates, putting additional cost pressure on limited bio-fuels supplies.

The next largest impact is the cost of compliance with the Cap and Trade program, most of which comes from making refiners responsible for 'tailpipe' emissions from transportation fuels (i.e. fuels under the cap). By 2020 we estimate the cost of compliance with fuels under the cap at 14-69 cpg and 2-8 cpg for stationary refinery emissions. The cost of compliance could be significantly higher if the cost of carbon rises above CARB's projected auction prices. An additional concern is that carbon costs could be extremely volatile initially, until robust market mechanisms are established. This volatility provides potential for market disruption and could result in significant costs for refiners and consumers in the near to mid-term.

Given the current regulations BCG believes there is a likely scenario where the cost of compliance requires refiners to recover in excess of 250 cpg and refiners are forced to reduce supply to the California market because they cannot get adequate supply of low CI bio-fuels or LCFS credits to stay complaint with LCFS.

This could happen in the 2015-16 timeframe if LCFS regulations are not modified. If the regulations are changed abruptly post 2015, the industry and California consumers will likely incur additional costs.

AB 32 fuels related regulations if fully implemented could result in California losing 28,000-51,000 jobs by 2020. 20-25% of these job losses could come from refineries ceasing production. Many of these will be high paying skilled manufacturing jobs (equipment operators, supervisors, engineers, etc.), with pay-scales ranging from $80,000 per annum and up. The rest of the job losses are a result of multiplier effects, and will likely be lower paying jobs in the service sector. Only a small number of jobs (2,500 to 5,000 direct and indirect jobs) are expected to be added as a result of energy efficiency projects and even these will be project based, not permanent in nature. Since bio fuels are imported, the majority of green jobs that are created will be outside of California.

Further, California could face up to $3.1-3.4 Billion per year in net lost tax revenues if AB 32-related regulations are fully implemented by 2020. The vast majority of this (~$2.9 Billion per year) will come from lost excise taxes on fuels, as fuel consumption will decrease and LCFS shifts consumption to fuels with lower tax rates. This net loss of excise tax could be even higher (up to $4.4 Billion), if the number of ATVs increase and volume of E-85 consumed is lower than projected. Any loss in excise tax could result in further reduction in employment in certain areas, such as road maintenance. In addition, corporate income taxes, personal income taxes, and sales taxes will all be reduced. Reductions in property taxes are expected to account for only $15-20 Million per year in tax losses, but could disproportionately impact counties and cities where refining facilities are located. Other implications include the loss of manufacturing related expertise and an increase in the cost of living due to the higher cost of fuels.

AB 32 fuels policies should be able to achieve the goal of reducing emissions in California by 80 million metric tons versus Business As Usual; however, some of this reduction will be at the expense of increased emissions elsewhere. A substantial amount of the emissions reduction will occur from shifting the composition of gasoline consumed in California from hydrocarbons to bio-fuels. However, there will also be unintended consequences that will increase global emissions and not decrease stationary emissions in proportion to the decline in hydrocarbon gasoline consumed in California. The regulations will likely result in crude and bio-fuels shuffling that will *increase* global emissions. Reduced fuel demand, driven by AB 32 fuels policies will force refiners to export fuels, leaving behind the stationary carbon emissions in California. Finally, new infrastructure will be required to accommodate new product imports and exports.

It is estimated that CARB could realize upwards of $3.7 Billion per year from sales of allowances by 2020 to refineries and other fuels suppliers. This amount could be higher if allowance prices are higher than CARB's minimum auction prices. It is not clear whether CARB has the authority to collect these revenues, nor is it clear how the state would use these funds.

As CARB and other entities contemplate changes to AB 32 fuels policies we believe there is a need and an opportunity to revise the regulations to support California's climate change objectives and economic aspirations while avoiding regulations that hinder economic growth and potentially introduce negative market dynamics (such as those that plagued electricity market deregulation).

3 Background and context

Pursuant to Assembly Bill 32 (AB 32), the California Air Resources Board (CARB) has promulgated regulations to reduce GHG emissions in California. These regulations provide monetary and other disincentives for GHG emissions to a variety of industry sectors. The top 5 sources of GHG emissions are road transport, electricity generation, ozone-depleting substances, refining, and residential fuel use. Industries covered under AB 32 include oil and gas (including extraction, refining, and marketing), power generation, manufacturing, public agencies (e.g., hospitals, universities), and other major GHG emitters. The end goal is to reduce emissions to pre-1990 levels by 2020.

Oil refining represents a significant share of total GHG emissions covered under AB 32 (almost 20% during the initial compliance period) and is the primary focus of this report.

3.1 *Overview of Climate change regulations*

Key provisions of California's climate change regulations that impact refiners are summarized below:

- <u>Cap and Trade</u> – The Cap and trade regulation sets an overall limit on the amount of GHG emissions. To stay compliant, companies must submit allowances to cover their GHG emissions each year. Allowances will be allocated to companies at no charge by the state, bought from the state at auctions, and/or traded on the open market. See Exhibit 1 for a summary of Cap and Trade regulations.

- <u>Low Carbon Fuel Standards (LCFS)</u> – To encourage substitution of transport fuels derived from crude oil with lower CI transport fuels, CARB is mandating reductions in the CI of fuels portfolios for all fuels providers. See Exhibit 2 for a summary of LCFS regulations.

- <u>Clean fuels outlets (CFO)</u> – A prerequisite for widespread adoption of new alternative transport fuels is the availability of fueling infrastructure. As such, CARB has decided that refiners and importers of gasoline must install CFOs for clean fuels (i.e., hydrogen).

- <u>Light/Zero Emission Vehicle (LEV/ZEV) standards</u> – LEV standards require car manufacturers to reduce GHG emissions per mile of their fleet. These are a further extension of previous programs to increase fuel efficiency. Furthermore, the accompanying ZEV standards specify that a certain amount of fleet fuel efficiency must come from the production of ZEVs.

Cap and Trade

AB 32 requires refiners to cap their GHG emissions and, in parallel, secure and submit carbon allowances to cover their emissions. Refiners can meet their commitments by using free allowances provided by the state, by purchasing allowances in auctions or in the open market, by reducing emissions, by acquiring offsets, or through a combination of these efforts. The regulation goes into effect in 2013 and has three phases (compliance periods). The first compliance period is 2013-2014, and the next two compliance periods are three years each, starting in 2015 and 2018, respectively. The regulation gets progressively more stringent and expansive in scope with each subsequent compliance period (see Exhibit 3).

To moderate the cost of compliance, refineries will be given a certain number of allowances at no cost by CARB. The portion of emissions covered by free allowances for the refining industry is determined by the Industry Assistance Factor (IAF), a declining cap factor, and a constant benchmark factor. The IAF varies by industry and, for refining, AB 32 has set an IAF of 100% during the first compliance period (2013-14), 75% in the second compliance period, and 50% in the third compliance period. The cap factor reflects the overall lowering of the cap in emissions and declines to about 85% by the end of the third compliance period. The constant benchmark factor is 90%. Thus, by the end of the third compliance period, only about 38% of refinery emissions are covered by no-cost allowances. CARB has specified the following methodologies for allocating free allowances to individual refineries in order to encourage refiners to increase the carbon efficiency of their processes while also mitigating the impact on the industry:

- First compliance period – The method in this compliance period relies on the Solomon Energy Intensity Index (EII). Lower Solomon EIIs indicate higher energy efficiency. Based on its proprietary refining models, BCG estimates that the average California refinery has an EII of approximately 95. Each refinery without a Solomon EII rating receives allowances based on either barrels of output or adjusted average annual GHG emissions, whichever is less. The remaining allowances are distributed among refineries with Solomon EII ratings based on adjusted historic emissions. A distribution factor takes into account the Solomon EII to distribute more credits to more efficient refineries. Two factors can increase or decrease the spread of allowances between the most and least efficient refineries. First, as the Efficiency Spread (measured as the ratio of the average EII to the best EII in the group) increases, the difference in the proportion of allowances allocated to each refinery decreases. Second, CARB calculates the ratio of the allowances allocated for the refineries in the EII group to the predicted emissions of that group. That ratio can range from 0.9 upwards. As the ratio increases, the difference in the proportion of allowances allocated to each refinery decreases, similarly to the Efficiency Spread. See Exhibit 4 for a summary of the allocation method and Exhibit 5 for a description of projected allocation.

  A unique aspect of the first compliance period is "true-up" of debits and credits. Because refineries with Solomon EII ratings will be allocated credits based on historic emissions, CARB has included a method to correct for changes in emissions during the first compliance period. If a refinery receives more allowances than its actual emissions (unlikely given the benchmark factor of 90% and the declining cap, but not impossible), they must surrender 80% of the difference (called a "true-up debit") at the end of the first compliance period. A refinery is allowed to keep the remaining 20% as an incentive to make quick wins in efficiency. On the other hand, if a refinery's actual emissions were greater than their baseline predicted emissions, they have the option of having their allocation recalculated at the end of the first compliance period based on their actual emissions and receiving a "true-up credit" for the difference. True-up debits and credits only occur at the end of the first compliance period.

- Second/third compliance periods – From the second compliance period onwards, the distribution of allowances will be allocated based on the carbon-weighted barrel approach. This approach was pioneered by the European Union (EU) and uses an extensive table of benchmark emissions per unit of throughput for each process. Each refinery's throughput for each process unit is used to calculate expected emissions for that process unit, and all the emissions are added up. A refinery's emissions efficiency is calculated by comparing actual to expected emissions. Allowances are then allocated based on a refinery's efficiency relative to the group.

The vast majority of refiners will need to purchase allowances to supplement their free allowance allocation and can do so using one of three options:

- General auction – Every quarter CARB will auction allowances. Participation is open to all entities that have registered with CARB and have on deposit the financial resources required to cover purchase of allowances.

- Reserve auction– If covered entities need additional allowances, these can be purchased through the reserve allowance process managed by CARB.

- Purchase from private entities – Registered participants can sell surplus allowances to other entities that need them either through bilateral transactions or through a commodity exchange (such as the Inter Continental Exchange). Due to limited ability for efficiency improvements and declining IAF, refineries are unlikely to have excess allowances.

Exhibit 6 shows a scenario where aggregate refinery emissions remain at the 2012 baseline of 32 million metric tons of CO_2. In this scenario, the refining industry would need to purchase allowances to cover 3.7 million metric tons of CO_2 emissions in 2013 rising to 19.7 million metric tons in 2020.

CARB provides covered entities with flexibility during each compliance period on the timing of when they submit allowances to ensure compliance. Each covered entity must submit sufficient allowances to cover 30% of its annual reported emissions during the year. At the end of the compliance period, the covered entity must settle its account by submitting sufficient additional allowances to cover its entire reported emissions during the compliance period. This allows a covered entity to run an annual deficit as long as it can settle its account at the end of the compliance period. Exhibit 7 shows how this would work using an example of a covered entity emitting 2 million tons of CO_2 in the first year, 1.8 million tons during the second year, and 1.5 million tons during the third year.

Offsets provide covered entities an alternative way to meet their compliance obligation by investing in projects that reduce GHG emissions elsewhere. Offsets can be used to meet up to 8% of a covered entity's compliance obligations. CARB has identified four types of projects that can be used to accumulate offsets during the first compliance period:

- Urban forestry
- Prevention of ozone-depleting substances
- Livestock manure projects
- Forest projects

Currently, only U.S. based projects are eligible, with the exception of REDD (Reducing Emissions from Deforestation and Forest Degradation) projects that would be located in developing countries. However, CARB may increase the scope and available geographic locations of eligible projects in subsequent compliance periods, potentially making offsets a cost effective method to achieve compliance. If an offset project is later deemed to be invalid, all offsets resulting from that program will be invalidated, regardless of who owns them or how they have been traded.

To be successful, Cap and Trade must overcome the following challenges:

- *Managing short-term volatility of the carbon market* – because mechanisms for assessing the true cost of carbon are still immature, the cost of carbon on the market could be more volatile in the early stages, resulting in carbon "shocks" (similar to oil "shocks"). CARB has limited options for adjusting the cap for changes in economic activity. When the economy declines, emissions fall naturally, resulting in a significant drop in the cost of carbon (as has recently occurred in the EU). Likewise, when economic activity picks up, emissions increase, which can result in a carbon "shock." Analogous "shocks" to the California economy resulting from regulation can be seen in the electricity prices of the early 2000s (see Exhibit 8). Thomson Reuters has forecasted carbon costs of $30-35/ton, but previous electricity shocks resulted in sustained electricity prices of 4 to 5 times the previous year's average. If this were to happen with the cost of carbon, the result could be costs of ~$150/ton of carbon.

- *Buyer liability of the offset program* – because offsets can later be invalidated regardless of the culpability of the holder, buyers take on a certain liability when they purchase offsets. In the long-term, this will result in a discount for offsets in the market, but buyer liability could also hinder growth of a strong and liquid market for offsets.

Fuels under the cap

Starting in 2015 (beginning of second compliance period), fuels suppliers, including refiners, will be responsible for emissions resulting from combustion of the fuels they supply ("tailpipe" emissions) under the Cap and Trade program. CARB will calculate the amount of GHG emissions resulting from the final combustion of all fuels sold and will add those emissions to the compliance obligations of refiners with respect to stationary emissions. Fuels suppliers will have to submit allowances to cover their compliance obligations for tailpipe emissions in the same manner as they will for stationary emissions. CARB has projected a large increase in the total number of allowances required in 2015; however, they have not provided official guidance on how these allowances will be allocated. If refiners are held liable for these emissions without any complementary increase in free allowances, as appears likely, our analysis indicates that they would likely need to recover these costs in order to continue meeting California's demand for fuels.

All of the challenges described in the section on Cap and Trade apply to Fuels under the cap as well; however, the scale of challenges is greater due to the significantly larger amount of emissions covered. Because final combustion accounts for the vast majority of the full lifecycle of GHG emissions from fuels, the costs will be significant and they will disproportionately impact lower income members of society, who spend a greater proportion of their income on transport fuels.

Low Carbon Fuels Standards

LCFS aims to reduce the CI of transportation fuels. Emissions are measured across the full life cycle of transportation fuels, including crude extraction; refining, transporting, and distributing the fuel; and combusting the fuel in vehicles. Exhibit 9 summarizes the sources of CI across the life cycle of transportation fuels. While crude extraction and refining are contributors, accounting for 9% and 14% of CI respectively, end-user combustion of transportation fuels accounts for 77% of total CI.

LCFS mandates that CI of fuels decline by 10% by 2020 with 1% of the decline achieved by 2013, an additional 4% by 2017, and an additional 5% by 2020 (see Exhibit 10). The compliance schedule requires CI for gasoline to go from ~95.8gCO_2e/MJ in 2011 to ~86gCO_2e/MJ in 2020 and CI for diesel to go from ~94.7gCO_2e/MJ in 2011 to ~85gCO_2e/MJ in 2020. Realizing this 10% reduction in CI is virtually impossible with current fuel technologies. Shifting to biofuels requires taking into account CI from land-use changes (i.e., the effects on carbon emissions if that land had been maintained in its natural state). When these effects are taken into account, only cellulosic ethanol and Brazilian cane ethanol have low enough CI to materially reduce the CI of existing fuels. Cellulosic ethanol cannot be produced in commercial quantities with today's technology, and Brazil does not produce enough cane ethanol to meet California's demand at the specified CI, even if all of it were sent to California. Current Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), hydrogen fuel cell, and Battery Electric Vehicle (BEV) technologies are not sufficiently advanced for widespread consumer use. Even if they were, it must be noted that hydrogen and electricity have CI values of their own, with current commercially viable hydrogen production techniques having higher CI than gasoline, which could result in a higher net CI impact.

CARB has compiled look up tables with standard CI values for fuels. Refiners receive credits if their fuel has lower CI than the standard and deficits if the CI exceeds the standard value. In addition, the following factors govern the amount of credits/ deficits generated for each fuel:

- Energy content of the fuel
- Fuel efficiency of Alternative Fuel Vehicle (AFV), as compared to a conventional gasoline/ diesel vehicle, if an alternative fuel is produced

CARB is developing a model to assess CI of crude oils being processed in California refineries and has a system whereby refiners as a group are penalized if the CI of their collective crude slate exceeds the CI of the baseline crude slate as measured in 2010. CI of crudes will be estimated based on their production characteristics using a model developed at Stanford University. For each unit increase in the CI of a given year's crude slate over the 2010 baseline, that amount of CI will be added to the compliance mandate, for all fuels and blendstocks derived from crude oil that year, further increasing the required CI reduction to be compliant. This could result in changes to the crude slate to minimize the penalty. This shifting of different crudes to different places is known as "crude shuffling" and could result in higher global GHG emissions, due to a net increase in transportation of crude oil (see section 4.4 for more information).

Refiners are not regulated on each fuel they produce, but on their overall fuel mix. To be compliant with LCFS, a refiner has to generate more credits than deficits from all fuels annually. In case a refiner has more deficits than credits, it has the option to buy credits from credit holders, such as suppliers of hydrogen, electricity, CNG, and LNG for transportation. Additionally, in case a refiner's shortfall of credits is less than 10%, these deficits may be carried over for one year with no penalty. Refiners can reduce the CI of their fuels by blending greater quantity of low CI biofuels into their fuels.

LCFS faces several challenges to implementation that are summarized below:

- 77% of total carbon emissions from crude oil based fuels are released during combustion. These emissions reflect the inherent chemistry of the fuel and cannot be changed. Thus, most of the reduction in CI will need to occur from changes in fuels and/or a steep increase in AFVs and Advanced Technology Vehicles (ATVs), rather than from process changes in the manufacture of fuels.
- Widely available substitute fuels such as corn ethanol have a similar CI to crude oil based fuels and do not materially help reduce the CI of fuels.
- Most low CI transport fuels (e.g., renewable hydrogen, renewable electricity) are relatively new and not supported by the current transport fleet. Mass market adoption of these fuels will take a long time and may require significant financial support, especially early in their lifecycle. Exhibits 11 and 12 illustrate scenarios developed by CARB that highlight the increase in number of AFVs required to meet LCFS mandated CI reductions. Under CARB's assumptions in this scenario, ethanol requirements are feasible, but their projections for AFVs are very aggressive. CARB projects that the number of FFVs in the light duty fleet will need to increase from an estimated 30,000 in 2012 to about 3 million by 2020 and over 500,000 new ATVs will join the light duty fleet. Furthermore, they project that 25,000 CNG vehicles and 8,000 Plug-in Hybrid Electric Vehicles (PHEVs) will join the heavy duty fleet. This amounts to an approximately 12% substitution of the light duty vehicle fleet and 4% substitution of the heavy duty fleet by 2020. For reference, it took nine years for gas-electric hybrids to reach 2.8% of the U.S. market, despite the availability of infrastructure (see Exhibit 13). CARB's projected substitution rates are very aggressive, especially when considering that
    - the technology for these vehicles is not yet developed for commercial use and may not be developed by 2020

- these vehicles may not be purchased by consumers because they will cost significantly more than conventional vehicles, and lack key performance characteristics (e.g. limited driving range)

- Substitute fuels that have low CI (e.g., Cellulosic ethanol, sugarcane ethanol) are not available in the required quantities. Exhibit 14 shows a scenario that highlights that meeting the LCFS-mandated reduction in CI solely with ethanol is not feasible. The scenario assumes that the ethanol mix is 65% Brazilian sugarcane ethanol (which has a lower CI), that standard gasoline will have E10, and that the rest of the difference in CI will be accomplished by substituting E85 for normal gasoline (i.e., E10). In order to meet LCFS targets, 85% of gasoline will need to be E85 in 2020, requiring approximately 150% of Brazil's current annual production of sugarcane ethanol each year. Infrastructure to transport this ethanol (not just fuels outlets but also terminals, ships, trucks, etc.) will need to be rapidly developed to meet California's demand. Californians will need to buy sufficient Flex Fuel Vehicles (FFVs) to consume significantly higher volumes of E85. Finally, even if consumers purchase FFVs they will only purchase E85 if it is more cost effective than E10.
- The ongoing legal challenge to LCFS is creating uncertainty that will discourage new investments in required technology and infrastructure.

While fuel suppliers can purchase LCFS credits to meet their obligations, trading in LCFS credits has yet to start in any significant manner, primarily due to market uncertainty surrounding legal challenges to LCFS implementation. There is no historic data on cost of LCFS credits and CARB has not defined any market mechanisms for how LCFS credits would be allocated and traded.

Clean fuels outlet regulation

CARB is mandating that major refiners provide the fueling infrastructure required to support new types of vehicles that run on clean fuels. These clean fuels originally included hydrogen, biofuels, and CNG, but newly proposed regulation only applies to hydrogen. CARB has stated that it intends for 87% of vehicles on the roads to be Fuel-Cell Vehicles (FCVs) by 2050 (the vast majority of which are expected to be hydrogen-powered). The regulation will take effect at a trigger level of 20,000 hydrogen vehicles delivered for sale in the state. Newly proposed regulation also includes a regional trigger level of 10,000 vehicles for a given air basin (as designated by California's air quality management districts). CARB has provided guidelines on the number of fueling stations required based on fleet size and expected demand, and they envision between 450- 500 clean fuel outlets being created over time. Responsibility for building CFOs will be allocated based on gasoline market share. CARB has also included a provision to suspend the regulation if gasoline refiners and importers sign a Memorandum of Agreement to build 100 hydrogen outlets. Regardless of whether such a memorandum is signed, CFO regulation will expire when hydrogen outlets equal 5% of all fuel outlets.

CFO presents a number of challenges, and these are summarized below:

- The market for clean fuel vehicles is nascent and current fleet growth projections are speculative. Adoption of any new technology is risky, and, if current growth projections do not materialize, refiners will have been forced to invest significant capital, with very limited certainty around the payback. If clean fuel vehicles do not enjoy market adoption CFOs could represent a significant HES (Health, Environmental, Safety) hazard for refiners and fuels retailers.
- Most refiners do not own and operate retail fueling stations. In order to set up CFOs, refiners would need to work through their dealers or with independent station owners, many of whom may have no interest in pursuing such opportunities. In addition, many refiners do not have existing business relationships with owners of retail fueling stations, further exacerbating the challenge.

- Refiners are being required to fund deployment of technology that would cannibalize sales of their existing products, creating an inherent conflict of interest.
- At least one third of the hydrogen produced and dispensed at fueling stations should be from renewal sources. Technology for this is currently immature and very expensive.
- CFO, in the manner that it is written currently, could get challenged legally.

LEV/ZEV standards

California has adopted targets for LEVs and ZEVs. The LEV mandate aims to reduce emissions from 251 gCO_2/mile in 2016 to 166 gCO_2/mile in 2025, consistent with current Environmental Protection Agency (EPA) guidelines. Total vehicle CO_2 emissions (roughly proportional to total gasoline burned) are projected to decrease by 12% from Business-As-Usual (BAU) levels by 2025 and by 34% from BAU levels by 2050.

CARB has also specified that a certain percentage of this decrease must come from the production of ZEVs. New regulations require that 15.4% of vehicles sold in 2025 be ZEVs (versus 4% under previous regulation). 15.4% of vehicles equates to approximately 1.4 million ZEVs on the road in 2025, including 500,000 BEVs and FCVs (primarily hydrogen). CARB plans for almost all vehicles sold by 2040 to be ZEVs in order to have a fleet of 87% ZEVs by 2050.

These requirements are aggressive, and uncertainty still exists as to how these mandates will be implemented. It is uncertain whether consumers will purchase the vehicles that are mandated to be delivered for sale. Plug-in hybrids and BEVs are expected to become significantly more expensive with each step in reducing GHG emissions. One reason is that the necessary battery technology faces significant hurdles in development. BCG research suggests that most consumers expect a payback time for the extra cost of their vehicle of 2-3 years, but fully electric vehicles are expected to be \$12,000-\$15,000 more expensive to purchase by 2020, even assuming significant technological advances (see Exhibit 15). Secondly, the use of ZEVs does not result in zero emissions. While the vehicle itself may not emit CO_2, the production of its energy source does. For example, current methods of producing hydrogen for FCVs are either more carbon-intensive than gasoline (i.e., steam methane reforming) or expensive and technologically not yet developed for commercial scale (i.e., photocatalytic water-splitting). Also, electricity is predominantly generated from burning fossil fuels such as coal and natural gas (though California has mandated 33% of its electricity to be generated from renewable sources by 2020).

CARB should use key indicators, such as its own scenarios, with year on year projections, to estimate if the legislation is having the desired impact (e.g. adoption of ATVs). If not, rapid, decisive action may be required to avoid unintended consequences.

3.2 *Current emissions from refineries in CA*

There are 14 fuels refineries operating in CA that range from world-class, highly sophisticated ("complex") refineries to simple, often subscale, refineries that may only operate seasonally. The refining market in California is very competitive, with a large number of complex refineries that maximize the production of refined fuels (gasoline, jet fuel, and diesel). Complex refineries have a greater number of process units and generate more GHG emissions per barrel of crude throughput relative to simple refineries.

Refining represents 8% of California GHG emissions at a total of 32 million metric tons of CO_2 in 2011. Refinery emissions come from three sources:

- Stationary emissions, which result from burning fuel to generate energy for the different process units of the refinery
- Process emissions, which come from the chemical reactions necessary to regenerate catalysts (i.e., burning of coke)
- Emissions from cogeneration, which is the simultaneous generation of heat for processes and electricity that can be used by the refinery or sold elsewhere

The BCG emissions model (discussed in Section 3.1) predicts that in 2011, approximately 14 million metric tons of CO_2 were generated from stationary combustion, about 11 million metric tons were generated from chemical processes, and the remaining 7 million metric tons were generated from cogeneration.

3.3 *Current market situation for refined fuels in CA*

The U.S. Department of Energy (D.O.E.) divides the country into five PADDs (Petroleum Administration for Defense Districts) to aggregate refining supply and demand figures. California is part of the West Coast PADD (PADD 5) which also includes Alaska, Hawaii, Oregon, and Washington. California accounts for about 2/3 of PADD 5 crude capacity and refined product consumption.

Exhibit 16 shows the trend of imports and exports in PADD 5. Gasoline supply is approximately equal to demand, while excess diesel supply is being exported, and jet fuel is being imported to meet demand.

California's 14 operating fuels refineries have produced a consistent yet steadily declining volume of refined fuels over the last few years, as can be seen in Exhibit 17. Currently, production of fuels (2011 average) is:

- Total gasoline (including blendstocks and ethanol): 1,039 thousand barrels per day (MBD)
- Distillates: 344 MBD
- Jet Fuel/Kerosene: 271 MBD[1]

As illustrated in Exhibit 18, the California market is both an importer and exporter of petroleum products. Jet fuel is imported from Southeast Asia to meet California demand. California was traditionally a net importer of diesel but has recently become a net exporter and diesel is exported to U.S. and overseas destinations. California refineries produce fuels for neighboring states like Arizona and Nevada. Gasoline has minimal imports and exports. The supply of gasoline from California refiners and blenders traditionally has matched the demand for gasoline in the state. Exhibit 19 shows the current supply/demand balance in California for gasoline.

4 Methodology used to analyze AB 32

BCG has developed a robust methodology to analyze the impact of AB 32 on the supply/demand for refined fuels in California, on refineries in PADD 5, and on California's economy and citizens.

4.1 *BCG methodology for emissions modeling*

BCG has developed a model for estimating emissions from both stationary combustion and chemical processes. Cogeneration is adjusted for in most CARB formulae, and it is not included in the model. A

[1] Refinery production numbers from California Energy Commission Weekly Fuels Watch

flowchart depicting our model can be seen in Exhibit 20. We start with raw data from publicly available sources and BCG's experience. The data from publically available sources includes:

- Energy required by each process unit (academic studies)
- Refinery process unit capacities (Oil and Gas Journal)
- Capacity utilizations (Energy Information Administration [EIA] data and company 10-Ks)

BCG has worked with at least 10 different oil majors and national oil companies, completing over 70 refining projects in the last 5 years. We have developed significant knowledge of refinery operations that we have leveraged in developing our emissions model. Data from BCG experience includes:

- Split between natural gas and fuel gas
- Emissions density per unit of energy
- Process emissions per unit of throughput

The process unit capacities and percent utilization are multiplied to get the throughput for each process unit, which is then multiplied by the energy intensity of each process unit to determine the total energy requirement. The energy requirements are apportioned between fuel gas and natural gas and multiplied by their respective emissions densities to determine emissions from each source. These two values are added to get total emissions from stationary combustion.

Multiplying the throughput calculated earlier for each process unit by the process emissions intensity yields the total emissions from chemical processes. We also use the energy requirements from our model to estimate the emissions efficiency of each refinery.

We calibrated our model by comparing the emissions predicted by our model to the actual emissions as reported to CARB. Total actual emissions for all refineries were only 7% higher than total predicted emissions. The model was further calibrated against the subset of highly emissions-intense refineries and refineries with low emissions intensity. To do this, we estimated the EII of each refinery and grouped them into three categories: most efficient refineries, average refineries, and less efficient refineries. We then compared the total predicted emissions to the total reported emissions of refineries in each group.

4.2 *BCG methodology for economic modeling*

Measuring the economic impact of AB 32 is a complex process due to expected changes in a number of market forces – most importantly the change in supply and demand for refined fuels. To estimate the impact of AB 32 on the California refining industry, BCG followed a five-step approach, illustrated in Exhibit 21. The methodology we took to model the industry is outlined below.

- Step 1: Evaluate the impact of regulations on demand
- Step 2: Establish supply/demand mechanisms and refinery economics
- Step 3: Sequentially take refinery production out of the region
- Step 4: Determine regional refining capacity at equilibrium
- Step 5: Conduct sensitivity analyses to test breakpoints

<u>Step 1: Evaluated impact of regulations on demand</u>

The first step in the process was to evaluate the impact of AB 32 on demand for refined fuels. While multiple components of AB 32 impact refiners, LCFS implementation has the most significant impact on demand for transportation fuels. In order to forecast the change in demand versus 2011, we determined the cumulative impact of alternative vehicles and ethanol blending year by year through 2020. The base demand forecast published in the *Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report,* published by the California Energy Commission (CEC) in August 2011, served as the base forecasted demand for the state. Adding the expected LCFS impacts to the base demand forecast created an updated demand profile incorporating the effects of AB 32.

<u>Step 2: Established supply/demand mechanisms and refinery economics</u>

Having established an understanding of how demand will shift during the three compliance periods, the second step was to establish supply/demand mechanisms and refinery economics. This step has three sub-steps:

2a. Created representative market environment (status quo) using BCG equilibrium pricing model
2b. Determined profitability of refineries in status quo using BCG refinery segmentation model
2c. Created regional supply/demand matrix for potential gasoline and diesel outlets

Exhibit 22 gives an overview of the overarching BCG refinery economics model which includes the BCG equilibrium pricing and refinery segmentation models.

<u>Step 2a: Created representative market environment (status quo) using BCG equilibrium pricing model</u>

Rather than use a single point estimate (e.g., average prices from the current month), which could include temporary market inefficiencies or seasonal effects, we used the BCG equilibrium pricing model to create a representative market environment to estimate the future state of a market. The primary output of this step is to generate a set of refined product and crude oil prices for use in the refinery segmentation model (further detailed in Step 2b).

The equilibrium pricing model estimates the relationship between crude and product prices in equilibrium. We believe that, at equilibrium, crude price equals the resulting product prices less variable operating costs in the marginal configuration. The marginal configuration is a refinery configuration in which the variable margin is at, or near, zero. In effect, the last barrel of crude to be run in a given region would be run in the marginal configuration. The marginal configuration varies over time depending on refinery throughput.

For California, different refined fuels have different market dynamics, depending on whether they are imported or exported. To account for this, we took monthly snapshots for the last twelve months to determine the likely marginal configuration at that point in time. We used a weighted average of these monthly marginal configurations to help create the price set to be used in the status quo environment.

The model uses the following inputs:

- Prices of refined products defined in relation to the price of regular unleaded gasoline
- Crude oil prices
- Cost of natural gas used for refinery processing
- Other variable costs of production (e.g., catalyst costs)
- Yields for selected process units such as FCC and Reformer

- The marginal refinery configuration

The equilibrium pricing model uses these inputs along with a comprehensive set of reference data to determine the marginal configuration at different points in time. Alternatively, the model can use a given set of crude prices and a marginal configuration to predict refined product prices. The model is calibrated to account for different product specifications (such as viscosity and sulfur in fuel oil) that can impact refining economics.

For studying the impact of AB 32, we used the following inputs to estimate equilibrium crude and product prices:

- Arab Light as reference crude with a FOB cost of $110/bbl.
- 2011 relationship of product prices (e.g., the price relationship between Regular and Premium gasoline, the relationship between diesel and gasoline, etc.)
- A Light/Heavy (L/H) differential of $25

The L/H differential is an approximate measure of profitability for refineries. It measures the difference between the price of light refined products and fuel oil. The more complex a refinery's configuration, the greater proportion of each barrel of crude oil it can convert into light refined products. Consequently, complex refineries are more profitable at higher L/H differentials. The differential is typically calculated as: [(Regular Unleaded Gasoline [RUL] + Ultra Low Sulfur Diesel [ULSD])/2] – High Sulfur Fuel Oil (HSFO).

Exhibit 23 shows that the average annual L/H differential based on West Coast product prices has settled in the $16-22 range over the last few years from a range of $33-36 during 2005-2008. The period from 2005-08 is widely considered the apex of refinery profitability in recent times. The monthly values for 2011 ranged from $13 to $34.

While $25 was selected to represent the status quo, we consider it likely that differentials will stay the same or decrease over the next few years. Hence, we included the impact of lower L/H differentials as one of our sensitivity analyses.

In addition to establishing a status quo market environment, the equilibrium pricing model is used in Step 3 to determine the new market price for gasoline and/or diesel as the supply available in the market changes.

Step 2b. Determined profitability of refineries in status quo using BCG refinery segmentation model

With an equilibrium price set established, we used those prices in the refinery segmentation model to estimate the profitability of each refinery on the West Coast (California and Washington). Refineries have different process units of varying relative sizes and process crudes with different characteristics. This results in each refinery having multiple configurations (or tranches) with each tranche producing a unique combination of refined products that collectively determine the profitability of the tranche. Profitability is highest for the most complex tranches since they produce the highest ratio of light refined fuels per barrel of crude oil. Profitability is generally lowest for simple tranches that produce a greater proportion of fuel oil for every barrel of crude oil.

Topping is an example of a simple tranche (crude oil is fractionated in a crude distillation unit [CDU] but no further processing takes place) and produces approximately 17% naphtha[2], 16% Jet fuel, 15% Diesel, 51% Fuel Oil, and 1% Liquefied Petroleum Gas (LPG), depending on the quality of the crude being processed. In contrast, a very complex tranche such as Coking/Hydrocracking[3]/Catalytic Cracking[4]/Alkylation[5]/Reforming[6] is shown in Exhibit 24 and includes the following steps:

- Crude oil is fractionated in an atmospheric crude still to make light products (e.g., naphtha, jet, diesel) and heavy products (gas oils and residuum)
- Residuum from the atmospheric crude still are further fractionated in a vacuum still
- Gas oils from the atmospheric crude still and vacuum crude still are cracked in a Hydrocracker to make light products
- Gas oils from the vacuum still are cracked in a Fluid Catalytic Cracker (FCC) to make light products
- Bottoms from the vacuum still are thermally cracked in the Coker to produce light products
- Light products are Hydrotreated to remove sulfur and then processed and blended to make saleable finished products.

Typical yields in the Coking/Hydrocracking/Catalytic Cracking/Alkylation/Reforming tranche are 4% LPG, 56% Gasoline, 23% Jet fuel, 19% Diesel, 6% Coke/Heavy Fuel Oil.

The refinery segmentation model takes a number of inputs:

- Refinery configuration (from Oil and Gas Journal)
- Process unit capacities and operating parameters
- Crude information including volumes and quality of crude processed
- Crude and product prices (from equilibrium pricing model)
- Natural gas prices
- Variable cost estimates

Key outputs of the model include:

- How much crude a refinery runs in each refining configuration
- Volume of refined products by product type (gasoline, diesel, jet, etc.)
- Key refinery constraints
- Variable margin for each refinery

To calibrate the segmentation model, we used a number of data points:

- D.O.E. company level imports for imported crudes
- Company and/or refinery level production data from public sources
- CEC state refinery output data
- EIA PADD 5 crude input qualities

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[2] Naphtha is a hydrocarbon mixture that is used primarily as a feedstock for producing gasoline and manufacturing petrochemicals

[3] Hydrocracking is the process of breaking down "long chain" hydrocarbon chains into shorter ones with the assistance of hydrogen

[4] Cracking process with the aid of a catalyst

[5] The process of upgrading chemical compounds (olefins) with isobutane to provide a high octane gasoline feedstock

[6] The process of converting naphtha to reformate, a high-octane gasoline blendstock

By calibrating against these sources, we ensure that the model accurately represents the California market. The resulting difference in predicted transportation fuel production vs. actual production for 2011 is less than 1%.

To include the cost of compliance with AB 32 (including Cap and Trade and Fuels under the cap), our methodology takes the following approach:

- Calculate emissions for each refinery through 2020, assuming a 5% decrease in emissions through energy efficiency improvements.
- Subtract allowances to be allocated for free (according to CARB's formula)
- Multiply the remaining emissions by the expected cost of carbon (weighted average of general auction and reserve auction prices)
- Assume that fuels will be sold in a market place where climate change regulations will not apply, preventing refiners from recovering the higher manufacturing costs resulting from climate change regulations

These variable margins, along with the compliance costs from the emissions model, established a baseline economic environment (status quo) for each refinery in California. It is worth nothing that the cost of key inputs into refining (e.g. electricity) might increase due to impact of AB 32 on other industries (like power generation); such impacts have not been considered in our financial modeling.

Step 2c: Created regional supply/demand matrix for potential mogas and diesel outlets

We next determined the balance of supply and demand for gasoline and diesel in California in 2017 and 2020 (to represent the second and third compliance periods). The supply of fuel was taken from the refinery segmentation model assuming that refineries consistently produce at PADD 5 average utilization levels.

In years where the forecasted supply exceeded demand, we considered the likely markets where refiners would economically export gasoline and the volume needed for meeting California's demand. Finally, we measured the relative attractiveness of these export markets to determine the order in which refiners would sell their fuel to maximize their profitability. The last market to receive fuel at a given point in time is the "least favorable" destination, and it determines the profitability of gasoline and diesel sales for the industry as a whole.

Step 3: Financially challenged refineries sequentially cease production

With refinery-level profitability and the supply/demand balance determined in Step 2, we use the refinery economics model to estimate the financial health of each refinery for a given period of time using the output of the refinery segmentation model (specifically the weighted average variable margin of each refinery). We performed this analysis for the status quo as well as for 2017 (end of second compliance period) and 2020 (end of third compliance period).

The primary output of the refinery economic model is the free cash flow for each refinery. To calculate free cash flow we used the following equations:

(Variable margin [from segmentation model] – fixed costs – depreciation) * (1-tax rate) = operating cash flow

Free cash flow = Operating cash flow + depreciation

The following was used to estimate the components of cash flow:

- Variable margin – weighted average of all profitable segments within the refinery (from the segmentation model), multiplied by productive capacity assuming an average PADD 5 utilization rate
- Fixed costs – based on publicly available financials and BCG case experience
- Depreciation – used a 20 year depreciation schedule; assumed 75% of depreciation is Property, Plant, & Equipment
- Taxes – used 36% corporate income tax rate

We went through an iterative process to determine which refiners would stop producing fuels due to the unfavorable export economics in 2017. Starting with the largest negative cash flow (adjusted for size of company – smaller companies would be less likely to sustain a negative cash flow of the same size as a significantly larger company), each refinery is assumed to cease production and convert to a terminal.

After each refinery conversion, we re-ran the economic model (including recalculating the cost of compliance) to review the fiscal health of each refinery and see if there are still refiners that cannot survive given the new supply/demand balance. The balance changes each time because, as refineries shut down, there is less supply available in the market. In some cases this would shift the "last barrel" of gasoline export to a more favorable export market, improving profitability for the remaining refiners.

<u>Step 4: Determine PADD 5 refining capacity at equilibrium</u>

Closely linked to Step 3, Step 4 takes the results from the previous step and creates a matrix for each scenario (status quo, 2017, 2020) showing the health of each refinery, including which would be shut down. This is the result of a final check that refineries that have ceased production remain non-producing at the new equilibrium pricing.

<u>Step 5: Conduct sensitivity analyses to test breakpoints</u>

In addition to analyzing the health of the industry using our initial assumptions, we tested key breakpoints (cost of carbon and L/H differential) to determine how they would further impact the industry. We based our analyses of breakpoints on the new 2017 equilibrium created in Step 4.

The first breakpoint studied was the impact of change in the cost of carbon allowances. First, we studied the effects of changing the price of carbon allowances from the weighted average of the general and reserve auction price to 80% of the reserve auction price. Second, we studied the effects on refiners if a majority of carbon allowances were purchased on the open market at substantially higher costs than the reserve auction costs. To determine the allowances needed on the open market we used the following assumptions:

- Refinery emissions from 2011 – CARB data
- Fuels under the cap – based on the CI and volume of fuels consumed in California
- Free allowances – based on CARB formula
- General and reserve auction volumes – based on carbon-weighted proportions of available allowances as specified by CARB
- Open market – assumed to account for the remaining volume

The second breakpoint studied was how a change in light/heavy (L/H) differentials changes the outlook for the remaining refineries in the 2017 baseline scenario. We did this by utilizing the equilibrium pricing model to come up with a set of prices for products and crudes based on L/H differentials of \$20/bbl, \$16/bbl, and \$13/bbl to test what L/H differentials would be required to cause any further capacity rationalization.

4.3 *BCG methodology for assessing AB 32 impact on California*

We assessed the impact of AB 32 on California along three major dimensions: effects on jobs, effects on taxes, and other effects. A flowchart of our methodology is shown in Exhibit 25.

Effect on jobs in California

Direct impact on jobs - The first category of jobs we considered is the direct number of jobs gained or lost. From our previous analyses, we predicted how many refineries are expected to cease production. Using our knowledge of refinery operations, we calculated how many employees and contractors would be out of work. In addition to lost jobs from refineries' ceasing production, there will also be reduced capital projects in the refining industry, and we estimated the number of employees and contractors who will lose their jobs from reduced capital expenditures. Offsetting these job losses will be the job gains from the implementation of energy efficiency projects.

Indirect impact on jobs - The second category of jobs we considered is jobs impacted by indirect effects. Using multipliers from government publications and previous studies, we estimated how many jobs will be gained or lost through indirect means for every job gained or lost directly. We used the total number of jobs lost through refinery capacity rationalization, reduced capital expenditures, and energy efficiency projects as the baseline to which we applied our multiplier.

Effect on taxes

Corporate taxes - California will receive lower corporate taxes from companies owning refineries that cease production. Additionally, other businesses will shut down or lose income, resulting in a further decrease in corporate taxes. Treating refinery expenses in a similar manner to reduced government spending allowed us to use the most recent multiplier numbers from the Congressional Budget Office (CBO) to calculate the negative effect on California's GDP. Using a regression of U.S. business income against U.S. GDP, we were able to determine how much business income will drop for each lost dollar of GDP. The lost business income was then used to calculate indirect lost corporate taxes.

Personal income taxes - Using our estimates of direct and indirect lost jobs as well as average salaries from the section on jobs, we were able to calculate lost income taxes.

Property taxes - We assumed that refineries that cease production will be converted to terminals and remain that way. Using the difference in property values between the refineries and the terminals yielded an estimate of lost property taxes.

Excise taxes - Using our LCFS scenario, we estimated excise tax loss as the projected reduction in gasoline and diesel consumption multiplied by their respective tax rates and excise tax gained as the projected increase in ethanol consumption multiplied by the California Use Fuel Tax for ethanol.

Sales taxes - Using our previously calculated change in GDP, we estimated sales tax loss as 80% of the reduction in GDP (assuming that 80% of GDP is taxable) multiplied by the average sales tax rate of California's districts. This is conservative because districts with more people tend to have both higher economic activity and higher sales tax rates

Other

Several other factors were considered. First, we determined the amount of revenue that California is expected to gain from the auction of allowances under the Cap and Trade program using known auction volumes and the cost of carbon in each auction. Second, we qualitatively considered the loss of manufacturing expertise to the state of California. Third, we considered the increase of fuels costs and the expected effect on cost of living in California. Fourth, we noted what amount of remaining emissions are "stranded" emissions; that is, the emissions resulting from producing refined products that will be exported as a result of LCFS. Finally, we noted the emissions to be reduced in the state of California per CARB's published cap.

5 Impact of AB 32 and related legislation on oil refiners

AB 32 is a far reaching legislative mandate that includes multiple components designed to reduce carbon emissions, create a market for trading carbon allowances, and encourage the adoption of vehicles powered by clean fuels. The key impacts of AB 32 are summarized in this section.

5.1 *Summary of the impact of individual regulations*

Each of the regulations stemming from AB 32 will impact refiners in different ways. In this section, the impact of each regulation is analyzed. Where appropriate, we support our analyses with analogs of how past regulatory changes have impacted industries, companies, and consumers.

Cap and trade (including Fuels under the cap)

The primary means by which Cap and Trade will impact refiners is through the cost of purchasing allowances, which will rise markedly in 2015 when refiners will be held responsible for the tailpipe emissions from transport fuels. As discussed earlier, refiners will have to buy any allowances that are not allocated to them for free; these purchases can be made in the general auction, the reserve auction, or on the open market. In order for California refining capacity to survive, we believe that the costs of purchasing these allowances would ultimately likely have to be recovered through sales of fuel. We estimate the level of such cost recovery from the Cap and Trade program in 2020 to be at least 16-77 cents per gallon (cpg).

To support our assumption that costs stemming from the implementation of Cap and Trade would need to be recovered through fuels sales, Exhibit 26 shows two cases of similar situations in which regulation was passed and the variable costs of compliance were recovered upon sale: the low-sulfur fuels legislation in Europe and North America that came into effect in 2006 and the CaRFG2 pollution emissions reductions for reformulated gasoline in California that came into effect in 1996. Also of note is the increased volatility in cost differentials around the time the regulations were implemented. This stems from uncertainty as to regulatory implementation, enforcement, and costs. It is likely that there will be volatility in the carbon market until it fully matures.

Exhibit 27 summarizes the estimated increase in necessary cost recovery from purchasing allowances for refinery emissions under different price forecasts and Industry Assistance Factors (IAFs). The following simplifying assumptions underlie this analysis:

- Production remains constant at 2012 levels
- Emissions are consistent with 2009 reported data
- IAF goes from 100% in first compliance period to 75% in second compliance period and to 50% in the third compliance period.
- Refinery achieves compliance exclusively by purchasing allowances.

- Allowances are sold between general auction and reserve auction prices

During the first compliance period, the estimated likely cost recovery required to meet California demand would amount to 0.3-1.2 cents per gallon, rising to 1-4 cents per gallon by the end of the second compliance period and from 2 cents per gallon up to almost 8 cents per gallon by the end of the third compliance period.

Exhibit 28 summarizes the estimated likely impact on the cost recovery required to meet California demand, when fuels under the cap are considered without refinery emissions, modeled with the following simplifying assumptions:

- Refinery production is constant from 2012 to 2020
- Refiners are charged for full combustion of fuels produced
- Refiners achieve compliance exclusively though purchase of allowances
- Allowances are sold between general auction and reserve auction prices

During the second compliance period, the estimated cost recovery required to meet California demand would increase to 12-60 cents per gallon versus the status quo, rising to 14-69 cents per gallon versus status quo by the end of the third compliance period. Thus, the total estimated likely cost recovery required by the end of the third compliance period would be 16-77 cpg. It is worth noting that the cost of allowances can exceed the reserve auction price, which would increase the total cost of compliance. See Exhibit 29 for the total estimated cost recovery we believe would be required to meet California demand resulting from the Cap and Trade program.

A second effect of the Cap and Trade program is that investments in energy efficiency that were previously not profitable or had an unacceptably long payback period could become more attractive. Some of these projects, their costs, and their effects on emissions are discussed in Section 4.3.

Low Carbon Fuels Standard (LCFS)

The primary effect of LCFS is destruction of demand for hydrocarbon fuels. This demand destruction results in changes in the economics of producing fuels, which is detailed in Section 4.2. Because of external market forces, it is not possible for all of these losses to be recovered, which will result in rationalization of California refining capacity. It is worth noting that 25-30% reduction in demand for gasoline in California will cause 4-6 California refineries (representing 20-30% of capacity) to shut down.

A second effect of LCFS is the current uncertainty concerning its legality. As of the publication of this report, LCFS had been declared unconstitutional by a federal district court, had an injunction issued against its implementation, been denied a stay of the injunction by that same district court, and had the stay granted by the Ninth Circuit Court of Appeals. As long as LCFS remains under legal challenge, market players (everyone from refiners to producers of alternative fuels) will not be able to assess the impact of these regulations on their business. Analysis of significant regulatory changes in the California power industry in the late 1990s (Exhibit 30) shows that the effect of uncertainty is a delay in new investment even when there is clear market demand. A similar result can be expected from the ongoing legal challenges surrounding LCFS.

Finally, if we accept the the highly optimistic assumption that Brazil can supply sufficient ethanol to meet California's demand we estimate that the level of cost recovery required by the industry to comply with LCFS would be in the range of 33-106 cpg (average 70 cpg) in 2010. This estimate is based on USDA forecasted prices for raw sugarcane and full reinvestment economics for the infrastructure required to make ethanol, transport it to California and store and distribute it to retailers.

In addition to the significant cost impact, there are several key uncertainties associated with LCFS that we have summarized below:

- Will legal challenge to LCFS result in uncertainty that stifles new investment?
- Is there sufficient sugarcane production capacity to meet rising global demand?
- Can industry participants overcome local challenges (e.g., construction permits) to develop logistical and other required infrastructure?
- Can refineries and other covered entities persuade non-covered entities (e.g., gasoline retailers) to support LCFS mandates like CFO?
- Is there a risk that distribution infrastructure gets fragmented across multiple fuel types resulting in fuels shortages?
- Unclear if the optimal bio-fuel is sugarcane ethanol, cellulosic ethanol or some other technology.
- Have robust market mechanics been fully thought through to avoid unintended consequences and market dynamics?
- Is there a risk of significant volatility, especially during the nascent stage of evolution of these markets?

Clean Fuels Outlets regulation

The primary effect of CFO regulation is a short-term increase in capital expenditures for refiners and importers of gasoline. This cost will likely be absorbed by refiners and importers, but depreciation on the investment will have to be recovered in order to replace the CFOs when their useful life is over. Using very conservative assumptions, the cost recovery is calculated to be in the range of 1 cpg assuming a 20 year depreciation schedule.

Refiners are also charged with maintaining the CFOs that they are responsible for building, which will result in some amount of operating expenses. It is unknown whether refiners will be able to derive any revenue from CFOs. There is the possibility of entering into revenue-sharing agreements with owners/lessors of retail stations or supplying hydrogen (though refinery hydrogen has very high CI, which will entail other costs). For our analysis, we have assumed that operating expenditures are offset by revenue; this is an optimistic assumption, and refiners and fuel retailers, many of who are small businesses, may have to bear incremental operating expenses and complexity. These costs would then need to be recovered much like the costs from Cap and Trade.

Finally, the CFO regulation imposes significant legal issues on refiners. CFO mandates would make refiners/importers legally responsible for installing and maintaining CFOs on the property of owners/lessors who may or may not welcome such a development, potentially resulting in legal challenges.

LEV/ZEV Standards

California LEV/ZEV standards are expected to have a minimal impact on refiners. There are no direct costs incurred, and the fuel efficiency of California's car fleet is unchanged compared to federal standards, though the current federal standards will result in reduced demand for refined products. The primary effect of ZEV standards is that it could accelerate the timeline for CFO requirements by mandating greater manufacture of ZEVs. See Exhibit 31 for implications of LEV/ZEV standards.

5.2 *Impact on refining capacity and utilization*

AB 32, specifically LCFS, is expected to fundamentally change the outlook for the refining industry in CA. Implementing LCFS in its current state will cause significant gasoline demand destruction, resulting in closures of several CA refineries. Results of our analyses are summarized below:

- CA refineries will be forced to export gasoline (currently expected to be to Mexico), by the end of the second compliance period (2017). As a result:
    - 4-6 refineries are expected to cease production and convert to terminals
    - CA will lose 20-30% of its refining capacity
    - Imports of jet fuel are expected to grow from Asia Pacific
    - CA will become a net importer of diesel from Asia Pacific

  It must be noted that gasoline export to Mexico is a temporary phenomenon. Once the 4-6 worse performing refineries cease production, supply and demand re-balance, which results in the marginal barrel of gasoline being sold in Phoenix, not in Mexico (based on current expectations). These refinery closures are projected to occur if there is gasoline demand destruction of 25-30% or higher.

- By the end of the third compliance period, driven by further reduction in gasoline demand, California refineries will continue exporting increasing quantities of gasoline, currently expected to be to Mexico. Following are the key impacts on the refining industry during the third compliance period:
    - 1-3 additional refineries are likely to cease production, bringing the total number of refineries expected to convert to terminals to between 5 and 7
    - An additional 5-10% of refined fuels production capacity is lost, resulting in a cumulative loss of 25-30% during all compliance periods
    - Imports of jet fuels will continue from Asia Pacific
    - Diesel imports are expected to more than double from 2017 levels by 2020

  It is key to note that LCFS implementation during the third compliance period (2018-20) depends on assumptions that are likely to be infeasible:
    - Significant increase in the number of Advanced Technology Vehicles (ATVs)
    - Majority adoption of E85 that requires massive volumes of sugarcane ethanol
    - Significant increase in Cellulosic ethanol blending

In addition to the regulatory impacts, BCG also evaluated the impact of key changes in the global oil industry, in particular narrowing of L/H differentials. It is estimated that L/H differentials at reasonable levels do not pose any additional threat to California's refining capacity.

In order to analyze the profitability of CA refineries, we used the five step evaluation process introduced in section 3.2 and grouped refineries into three categories, based on profitability (see Exhibit 32):

1. "Distressed" – refineries generating free cash flow of negative $30 million/year or worse. Refineries in this category are expected to cease production
2. "May survive" – refineries generating free cash flow of between +/- $30 million/year. Refineries in this category would continue producing, but would be at risk of ceasing production if economic conditions deteriorate
3. "Will survive" – refineries that are the strongest performers in the region and have significant positive free cash flow, in excess of $30 million/year. Refineries in this category would continue to produce and have the ability to withstand temporary economic downturns

In general, the CA refining industry features relatively complex refineries that have historically had above average levels of profitability relative to the U.S. in general. The recent decrease in L/H differentials since 2008, however, has put some of the existing refining capacity at risk. Exhibit 33 shows that in the current equilibrium, 10-20% of the refining capacity in California is considered at risk, with 3-5 refineries in the "may survive" category.

Step 1: Evaluate impact of regulations on demand

Given this status quo, we studied how demand destruction caused by LCFS might impact refining capacity and utilization in CA. Usually when the refining industry is stressed, refiners have the option of cutting crude runs, running only enough crude to fill the process units in the refinery that generate a positive variable margin. In the case of U.S. West Coast refiners in 2012, utilization is near 30-year lows as shown in Exhibit 34. The refiners currently in the "may survive" category have already reduced runs. Given the current environment, it is unlikely that an industry response to any sustained change in product demand would be to reduce utilization any further. The next step would be for marginal refiners to cease production. In our analysis, we assume that the industry continues to have an average throughput equal to the PADD 5 average for 2011 (i.e., 81.9%).

Exhibit 35 shows our demand forecast considering the impact of LCFS. We believe that there will be a significant excess supply of gasoline in CA in the second and third compliance periods if all refineries were to continue to operate.

Exhibit 36 illustrates the new trade flows that would potentially occur starting in the second compliance period. Post-regulation, California becomes a larger importer of jet fuel and a very large exporter of gasoline. It is important to note that refiners have limited ability to correct this supply/demand imbalance (i.e., produce more jet fuel and less gasoline) by making operational changes. The relative quantity of each fuel produced (e.g., gasoline, jet fuel, diesel) when a refinery processes a barrel of crude is pre-determined based on the characteristics of the crude (such as its API gravity) and the refinery configuration (such as the amount of conversion capacity). Refineries can make some operating changes to decrease gasoline production and increase diesel/ jet fuel production but within very narrow bounds. They cannot accommodate the projected steep decrease in gasoline demand simply by changing their operating parameters.

Step 2: Establish supply/demand mechanisms and refinery economics

In order to determine the health of refiners who are now required to export gasoline, we looked at the attractiveness of export markets for gasoline given 2011 average prices. We found that, in decreasing order of attractiveness, product would be shipped to Seattle, Hawaii, Phoenix, and Mexico/Latin America (based on current expectations). Exhibit 37 shows the relative attractiveness of each market and the export volume available. To determine the relative attractiveness of each market, we started by considering the next best alternative exporter for each market (e.g. Gulf of Mexico/ Singapore etc.), factored in costs of transporting the fuel and costs of making quality adjustments in order to get to the final price for fuel in the market. The difference between that price and the price realized by selling products locally in CA, determines the relative attractiveness of each market. Volumes that could be exported to each market were estimated based on data from pipeline companies and other public domain data. Once attractiveness and available export volumes were determined for each market, volumes were sequentially placed in each market, in decreasing order of attractiveness, until each market was saturated, and all excess CA gasoline was placed.

In 2017 (the second compliance period), the volume of gasoline produced is enough to saturate the local California market as well as other U.S. export markets (Seattle, Hawaii, Phoenix), forcing refiners to export gasoline to Mexico (based on current expectations). As refiners export gasoline to Mexico, the netback[7] on gasoline decreases significantly, impacting the profitability of all refiners. Exhibit 37 shows a representation of the potential export markets and volumes using 2011 average prices. These relationships change over time, but markets outside of the U.S. (e.g., Mexico) always deliver a significantly lower netback than U.S. markets, primarily driven by transportation and quality adjustment costs.

Step 3: Sequentially take refinery production out of the region

Under this market environment (i.e., refiners exporting gasoline to Mexico), 25-35% of California's refining capacity would be "distressed", as shown in Exhibit 38. Going through the evaluation/shutdown process described in Section 2.3, we predict that 4-6 refineries with the worst cash flow estimate would cease production changing the supply/demand balance (shown in Exhibit 39). This would bring down gasoline supply by 165 mbpd, resulting in the marginal barrel being exported to the financially more attractive Phoenix market than to Mexico (based on current expectations). Further, the new equilibrium shifts the trade balance for diesel as well, driving the need for 26 mbpd in imports.

Step 4: Determine regional refining capacity at equilibrium

Given the change in refinery supply due to refineries shutting down, gasoline would no longer be exported outside of the U.S. and refineries would be operating at a Phoenix netback (based on current expectations). In addition, diesel would switch from being an exported product to being an imported product.

In this new equilibrium during the second compliance period, with diesel imports and gasoline exports to U.S. markets, 4-6 refineries representing 20-30% of the CA refining capacity would remain shut, but the remainder of the industry shifts to the "Will survive" category as shown in Exhibit 40. Compared with the initial prospect of exporting product to Mexico, the industry as a whole improves as gasoline production decreases driven by 4-6 refineries stopping production permanently in the second compliance period. Exhibit 40 represents the new equilibrium in 2017. Exhibit 41 shows a supply/demand balance of gasoline in California in 2017 after projected shutdowns.

If regulations in the third compliance period are implemented as currently designed, the effects on California's refining industry would deepen. As demand destruction accelerates after 2017, the refineries that were previously in the "distressed" and "may survive" categories in Exhibit 38 have no remedy as the exports outside of the U.S. continue even after the initial shutdowns. Because of this, refining margins will be determined by netbacks to lower netback destinations of Mexico and Central America (based on current expectations) (see Exhibit 42). In this scenario, the refining capacity that is shut down increases to 25-35% of California capacity (5-7 refineries) and an additional 35-45% of capacity is at risk (see Exhibit 43). This means that at least 60% of 2012 refining capacity will be either in the "distressed" or "may survive" categories in the third compliance period. Exhibit 44 shows a supply/demand balance of gasoline in California in 2020.

Step 5: Conduct sensitivity analyses to test breakpoints

After evaluating the impact of demand destruction on the status quo for CA refiners, we evaluated the impact of a change in the cost of carbon and L/H differentials.

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[7] Netback is equal to revenue less transport cost

We found that changing the cost of carbon will not alter the amount of refining capacity rationalized, although significant increases in the cost of carbon would increase the cost recovery required by the industry, as detailed in Section 4.5

Changes in L/H differentials have a significant impact on the refining industry. When looking at the effect of changes in the L/H differential versus the 2017 "new status quo", the effect is minimal. The remaining refineries are strong enough to weather L/H differential changes within a reasonable band (as low as $16). Though L/H differentials have narrowed significantly in recent years, $16 is the lowest annual average that the industry has seen during that time period (as shown earlier in Exhibit 23). Exhibit 45 shows the increase in refineries considered "distressed" as the L/H differential decreases. L/H differentials as low as $16 put a number of additional refineries at risk but do not result in any additional loss of capacity (relative to the 2017 equilibrium). If the differential were to approach $13, an additional loss of 30-40% of refining capacity could occur. However, $13 L/H differentials represents historical lows and has not been sustained for more than a few months (see Exhibit 23).

5.3 *Impact of GHG abatement options*

Most refineries in California are already very energy efficient, and energy efficiency projects that have a positive return on investment will reduce refinery emissions by only small, incremental amounts. Based on our experience, we estimate that California refineries could reduce emissions by approximately 5% by implementing energy efficiency projects.

5.4 *Changes in crude slate*

In order to avoid the LCFS penalty for higher CI, refiners might re-optimize their crude slates. In order to balance out the CI of the crude slate, refiners may seek to replace their crude slate with the lowest CI crudes that are economically suitable. Locally available high CI crudes will trade at a discount and could be exported to locations with no LCFS regulation, while low CI crudes could be imported into California. This process is called "crude shuffling," and it can result in higher global GHG emissions than the status quo due to incremental crude transportation. For example, San Joaquin Valley (SJV) crude is a high-CI crude that is consumed primarily in California. In order to minimize LCFS penalties, SJV could be exported from California to refineries elsewhere resulting in incremental emissions from transporting the crude. Further, SJV value will decline to reflect the incremental transport costs, resulting in lower revenues for state of California.

5.5 *Estimate of the likely range of cost recovery required in cents/gallon to meet CA demand*

Overall, we believe that refiners would need to recover compliance costs of at least 49-183 cpg in 2020 in order to meet California demand, 2-8 cpg of which would be due to the refinery emissions component of the Cap and Trade program. 14-69 cpg would be due to Fuels under the cap and 33-106 cpg would be due to LCFS. We expect required cost recovery for the CFO program to be nominal if spread out over the lifetime of the outlets, assuming minimal or offset operating costs. LEV/ZEV mandates are expected to have a minimal impact.

This cost recovery analysis assumes that sugarcane ethanol is available in sufficient quantities (mainly from Brazil) to achieve LCFS compliance. As noted earlier, this assumption is highly optimistic for a number of reasons:

- Brazil is the by far the largest producer of sugarcane ethanol and its total production is less than California's demand in 2020 (assuming LCFS compliance were to be achieved solely through ethanol blending).
- Brazil already exports a significant amount of ethanol to the US to meet existing demand.
- Brazil relies on its sugarcane ethanol to meet a large portion of its domestic demand for fuels.
- Other countries, notably the European Union import sugarcane ethanol from Brazil to meet their demand for fuels.

Additionally, it is highly likely that there will be some increase in the cost of Brazilian sugarcane ethanol in order to stimulate the increased investment necessary to meet California demand; however, the magnitude of the potential increase is difficult to predict and not included in our analysis.

CARB's assumptions for development of low CI hydrogen or electric vehicles at prices that would spur widespread consumer adoption, are equally aggressive as are the projections for availability of cellulosic ethanol. Without such development, there will be no supply of LCFS credits; therefore, it is difficult to predict the price of LCFS credits with any degree of accuracy. Without sufficient sugarcane or cellulosic ethanol or adequate LCFS credits, refiners will be unable to meet the LCFS and will be forced to cease production or export even more fuel, potentially resulting in disruption of fuels supply throughout California. While it is difficult to quantify the financial impact, we believe that this potential for disruption of California's fuels supply is sufficient to make LCFS unviable. Further, more states such as Oregon are considering implementing LCFS policies, which will put additional cost pressure on limited biofuels supplies and increase the cost of implementing LCFS.

As discussed in Section 4.1, LEV/ZEV standards are unlikely to have a significant impact on refiners. Thus, the regulations likely to impact estimated total cost recovery requirements the most are Cap and Trade, LCFS, and CFO. The CFO regulations require the construction of anywhere from 100 to over 450 CFOs by 2020. At \$2 million per outlet, this totals \$200 million to \$900 million dollars of capital expenditures spread across the industry. Assuming a depreciation schedule of 20 years yields a cost recovery estimate of less than 1 cpg for the entire range in 2020 (assuming breakeven operating costs). If clean fuel vehicles do not enjoy market adoption CFOs could represent a long term HES risk for refiners and fuel retailers, the cost of which has not been quantified.

To estimate the level of cost recovery that would be required as a result of Cap and Trade, we multiplied the projected emissions of refineries and their obligations under Fuels under the cap by a range of carbon cost of \$14-\$70 in 2020 to yield a total estimate of 45-170 cpg. Exhibit 46 shows a chart of the estimated cost recovery needs by regulation with accompanying assumptions.

Perhaps the most critical assumption in our calculation of total cost recovery needs is the cost of carbon. In 2015, when Fuels under the cap comes into effect, the annual supply of allowances will roughly double. While it is not yet clear how those allowances will be allocated, a comparison of refineries' obligations at the end of the second compliance period (2017) to the amount of free allowances they can expect to receive, their carbon-weighted share of the general auction, and their carbon-weighted share of the reserve auction shows a substantial gap that must be purchased on the open market unless CARB allocates the new allowances to either refineries or to fuels consumers. This gap, assuming refiners receive allowances from CARB at current allocations and can purchase allowances in each auction at the minimum price in proportion to their fraction of total emissions, is shown in Exhibit 47, left panel.

Sensitivity analysis on the cost of carbon shows that higher carbon costs have large effects on the estimated required cost recovery:

- Estimated cost recovery in 2017 for Cap and Trade would be 157 cpg at \$150/metric ton of CO_2 (see chart on Exhibit 47, right panel).
- Estimated cost recovery in 2020 for Cap and Trade would be at \$150/metric ton of CO_2.

While we have attempted to estimate the level of cost recovery that would theoretically be required by the industry in order to continue to meet California demand, individual company decisions regarding what level of costs need to be recovered and can be recovered are, and will of course be, influenced by a broad range of factors and are therefore likely to differ from and could be outside the ranges of cost recovery that have been estimated in our analysis.

6 Implications of AB 32 for California

AB 32 related regulation will have significant impact on California. Some important things to consider are the effects of these regulations on employment, tax revenue, revenue from selling allowances, GHG emission reductions, cost of living increases, etc. In this section, we detail these effects in three categories: employment impacts, tax revenue impacts, and other impacts. It should be noted that the impacts considered are limited to refining and related industries only. The overall impact, once all covered entities are considered, will be much greater than what is discussed in this section.

6.1 *Impact on employment in California*

California could lose between 28,000 to 51,000 jobs by 2020 as a result of AB 32-related regulation and its collective impact on the refining sector. These job losses will result from a combination of both direct and indirect effects. Direct impacts include job losses due to conversion of unprofitable refineries to terminals and job losses from reduced capital expenditures from refineries that are no longer processing crude. These job losses would be partially offset by jobs driven by energy efficiency projects. Indirect impacts are the result of lost jobs from sectors that serve the refining sector and its employees. For example, refineries buy large quantities of steel pipes. This creates jobs in pipe manufacturing, metal mining, imports/ exports, trucking, etc. for which there will no longer be demand. Also, refinery employees eat at local restaurants, go on vacation, and take their families to the movies. Reduced disposable income will reduce demand for these services resulting in job losses in these businesses. These employment figures are summarized in Exhibit 48.

California could lose 600-700 MBD of refining capacity by 2020. As a result, the state could lose between 4,000 and 4,900 jobs by 2020 (see Exhibit 49). Of these, 2,400-2,900 will likely be hourly workers or contractors, 1,300-1,600 will likely be of "supervisor" rank (non-exempt employees who may have direct reports but frequently do hands-on work), and the remainder will be support staff or managers. On average, these are jobs pay approximately \$100,000 to \$150,000 per year.

Additionally, reduced capital expenditures by refineries that are expected to cease production could drive an additional 1,000-2,000 job losses by 2020 (see Exhibit 50). This will be only partially offset by the 400-600 jobs that could be created by increased investment in energy efficiency projects (see Exhibit 51). These jobs can be expected to be of similar pay to the direct employment at refineries.

The majority of job losses for California are a result of indirect impacts. The state could lose between 23,000 and 45,000 jobs by 2020 on account of indirect impacts. While these jobs do not include contractors, they do include suppliers as well as jobs in various goods/services sectors supported by the employees and contractors of the refineries. In order to estimate these numbers, BCG used multipliers that were generated by prior studies, Bureau of Economic Analysis (BEA) data, and the U.S. Census Bureau, as shown in Exhibit 52.

Based on this data, we assumed a jobs multiplier range of 5-7. These jobs are expected to pay approximately $40,000 to $60,000 per year. See Exhibit 53 for a summary of jobs gained and lost due to multipliers.

It should also be noted that the mandate to build CFOs could create 1,000-11,000 jobs as a result of building CFOs and the indirect effects stemming from that activity (assuming an additional multiplier of 0.5-1.5 based on a U.S. Census Bureau additional multiplier for gas stations of 0.6). However, these jobs will be temporary rather than long-term and are not expected to produce economic value without much more rapid adoption of hydrogen FCVs than we project. Thus, they were not included in our total jobs count.

6.2 *Changes in tax revenue*

Overall, California's state and local governments could lose $3.1 – 3.4 Billion per year due to AB 32. The largest impact will come from changes in excise taxes, which will result in annual reductions of $2.9B annually. Other significant impacts include corporate tax losses of $80-230M annually, personal income tax losses of $70-115M annually, and sales tax losses of $50-140M annually. Property taxes have a small impact of $15-20M in revenue losses annually. These numbers are summarized in Exhibit 54.

Corporate Tax

California could lose $80-230 M per year in corporate tax revenues by 2020 (see Exhibit 55). Only a small portion of this (<$10 M per year) comes from refineries themselves; refineries that are expected to cease production currently have small or no taxable income. However, the reduction in refinery spending will propagate throughout the economy, reducing GDP and business income. The ratio of refinery spending losses to taxable business income was estimated to be 0.27-0.68. This is the product of a spending to GDP multiplier of 1 to 2.5 (derived from analysis carried out by the Congressional Budget Office) and a GDP to taxable business income ratio of 0.27 (determined by linear regression). Thus, we concluded that with estimated lost refinery spending of $750-900M per year, multiplier effects could result in a decrease in taxable business income of $200-610M per year, resulting in $70-220M of lost corporate taxes.

Personal Income Tax

Personal income taxes make up the majority of the state government's tax receipts, and the loss of jobs throughout the state will result in a commensurate loss of tax receipts. Applying California's tax brackets to the expected earnings of employees projected to lose their jobs indicates that the state government could lose $70-115M per year in personal income taxes (see Exhibit 56). This does not include impact on federal income tax receipts or the possible effect on the federal budget, some of which flows to California, because historical federal spending has reacted minimally to changes in receipts. However, due to budget realities, it is possible that this reduced income could eventually impact federal projects in California.

Property Tax

When refineries convert to terminals, it is likely that their property values will be reappraised. As a result, California localities could collect lower property taxes. We estimated the value of refineries by multiplying an average value factor from recent refinery sales by capacity in barrels per day by the Nelson complexity factor. Terminals were assumed to have an average value of $20M. Based on this analysis, we project that California localities will lose between $15M and $20M annually by 2020 (see Exhibit 57). Because these taxes go to local rather than state governments, the effects will be distributed disproportionately across localities.

General Sales and Use Tax

The general use and sales tax is the state's second largest source of income. As discussed in the section on corporate taxes, California will likely experience reduced GDP as a result of reduced refinery spending. Using reduced refinery spending and the aforementioned spending multiplier of 1 to 2.5 from CBO analysis, we project reduced annual sales tax of $50-140M to California's state and local governments because of reduced refinery spending (see Exhibit 58). This assumes that 80% of GDP is taxed and that the cumulative state and local sales tax is an average of 7.8%. This sales tax rate is the average of all localities, which is conservative because more populated localities tend to have higher tax rates.

Excise Taxes for Fuels

AB 32-related measures, specifically LCFS, will result in a change in the composition of fuels. In addition, fuel consumption will be lower in the future, resulting in reduced excise taxes. Ethanol is also taxed differently than gasoline. Because of these two effects, California can expect to lose $2.9B per year in excise tax on fuels (Exhibit 59). This analysis takes into consideration expected gains from excise tax on E85.

6.3 *Other impacts on California*

In addition to effecting jobs and taxes, AB 32 will impact California on multiple additional dimensions. These include positive impacts, such as revenue generation from the sales of allowances and reduced GHG emissions, as well as negative impacts, such as loss of professional expertise and increased cost of living. See Exhibit 60 for a summary

Based on CARB's projected allowance budget and minimum auction prices, CARB can expect to earn at least $3.7 B annually by 2020 from the sales of allowances (see Exhibit 61). Most of this will be driven by a large increase in allowances in 2015 to account for fuels under the cap. However, it is possible that CARB will allocate some or all of these allowances for free, which would reduce expected earnings. It is also possible that the general auction settlement price could be much higher than the minimum, greatly increasing the amount of revenue CARB can expect to generate. It is uncertain whether CARB has the authority to collect this scale of revenues or how it intends to spend the money.

As described in Exhibit 62, loss of economic activity in the refining sector (as well as other industrial sectors) will result in fewer job opportunities or projects of interest for engineers, specialized mechanics and tradesmen, and supporting professional services (e.g., project management). As a result, more people with experience in these areas are likely to leave the state, and fewer Californians might seek training in such areas in the first place. This loss of supply of qualified people in these fields will have an effect on California's business environment that is difficult to quantify, but is definitely negative.

Transportation dependent industries are likely to see the highest increases in costs, which will need to be recovered upon sale of products and services. Example industries that are expected to have particularly high cost inflation are trucking, railroads, airlines, taxis, bus service, logistics (e.g., FedEx or UPS), marine transportation, and independent workers (e.g., plumbers, furniture movers, maids). There are other industries that will face cost pressure for reasons other than transportation dependence, and they will be affected similarly. Other industries that are likely to experience high cost inflation include farming (farm equipment uses diesel), manufacturing facilities with diesel turbines, and construction. The products of these industries are more widely distributed throughout the economy, and increased costs in these industries may therefore have a more significant impact. Public transportation will also face budgetary pressures due to higher fuels costs. Ultimately, almost every business relies on transport or fuels consumption at some point in the value chain, resulting in a general increase in the cost of living in California. See Exhibit 63 for a description of cost of living increases.

In 2008, as AB 32-relevant measures were being developed, CARB originally forecasted GHG emissions of 596 million tons CO_2e for 2020. To get to the goal of 1990 levels (427 million tons CO_2e) would require reductions of 169 million tons CO_2e. Revised economic forecasts in 2010 indicate that GHG emissions will be 507 million tons CO_2e for 2020, reducing the required emissions reductions by over 50% to 80 million tons CO_2e. Thus, we attribute 80 million tons of CO_2e emissions reduction to the AB 32-related measures planned by CARB. However, it should also be borne in mind that many California refineries will continue producing fuels for export. Thus, two effects must be further considered: 1) up to 12 million additional metric tons per year of emissions remaining in California will be the result of producing fuels for export due to LCFS (see Exhibit 64) and 2) a substantial amount of GHG reductions (~72 million tons CO_2e) will occur from transporting end-use of fuels produced in California to locations outside of California without any reduction in global emissions.

7 Glossary

AB 32 – Assembly Bill 32
AFV – Alternative Fuel Vehicle
ATV – Advanced Technology Vehicle
BAU – Business-As-Usual
Bbl – Barrel
BEV – Battery Electric Vehicles
CA – California
CARB – California Air Resources Board
CCA – California Carbon Allowances
CDU – Crude Distillation Unit
CFO – Clean Fuels Outlets
CI – Carbon Intensity
CNG – Compressed Natural Gas
CO_2 – Carbon dioxide
CPG – Cents Per Gallon
D.O.E. – Department of Energy
EIA – Energy Information Administration
EII – Energy Intensity Index
EPA – Environmental Protection Agency
FCC – Fluid Catalytic Cracker
FCV – Fuel Cell Vehicles
FFV – Flexible Fuel Vehicle
GHG – Greenhouse Gas
H_2 - Hydrogen
HSFO – High Sulfur Fuel Oil
IAF – Industry Assistance Factor
L/H – Light/ Heavy
LCFS – Low Caron Fuel Standards
LEV – Light Emission Vehicles
LNG – Liquefied Natural Gas
LPG – Liquefied Petroleum Gas
MBD – Thousands of barrels per day
MJ – Megajoules
MM – Million
PADD – Petroleum Administration for Defense District
PHEV - Plug in Hybrid Electric Vehicle
REDD – Reducing Emissions from Deforestation and Forest Degradation
RUL – Regular Unleaded Gasoline
ULSD – Ultra Low Sulfur Diesel
ZEV – Zero Emission Vehicles

8 Sources

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Magellan
Nelson
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Renewable Fuels Association
Solomon
Thomson Reuters
U.S. Census Bureau
US Department of Energy
Wood Mackenzie
World Bank

9 Exhibits

Exhibit 1

Cap regulates industrial actors for emissions along the whole value chain

Crude extraction

Refining

Transportation and Distribution

Combustion in vehicles

Refiners are held accountable for all emissions from refining through final combustion (Fuels under the cap comes into effect in 2015)

Source: CARB

CO_2 emissions must be balanced by offsets or purchase of allowances

Regulated entities must surrender one allowance or offset credit for each metric ton of CO_2 produced

In order to moderate impact of cost of compliance of producing fuels, industry players are allocated free allowances each year based on output

- Industries are allocated allowances differently based on different measures of output
- IAF is used to vary allocation of free allowances over time
- Refineries are allocated extra allowances for more efficient production

Allowances that are not allocated for free will be put into pools for auction

- General auction contains a large number of allowances at a relatively low cost
- Reserve auction contains a small number of allowances at a "soft" cost ceiling
- Percentage of allowances in each pool varies by compliance period

Exhibit 2

Carbon intensity measures emissions on a "well-to-wheels" approach

Crude extraction

Refining

Transportation and Distribution

Combustion in vehicles

Source: CARB

Standard values need to be adjusted if processes are different from average

CARB look up tables for standard carbon intensity values for each fuel

Fuel	Pathway Description	Carbon Intensity Values [illegible]		
		Direct Emissions	Land Use or Other Indirect Effect	Total
Gasoline	[illegible]	[illegible]	0	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]

Adjust for deviations from standards in production, refining, etc.

- Prove to CARB that crude extraction or refining process is significantly different from average
- Calculate change in carbon intensity as a result of differences

Calculate final carbon intensity of produced fuel in gCO2e/MJ of fuel

Exhibit 3

	Compliance Period 1 (2013-2014)	Compliance Period 2 (2015-2017)	Compliance Period 3 (2018-2020)
Cap and Trade	Buy allowances for carbon emitted beyond Cap 100% Industry Assistance Factor (IAF) Refining sector allocation based on simple barrel approach Individual allocation by combining EII[1] values and simple barrel approach Refiners with calculated Solomon EII values surrender 80% of excess allocated credits; can get allowances recalculated based on actual emissions at the end of first period Up to 8% of obligations can be from offsets of which up to 2% may come from REDD[2] programs	Reduced Cap 75% IAF All allocations based on carbon-weighted barrel approach[3] Fuels under the cap comes into effect No penalty for excess allocated credits and no recalculation of allowances Up to 8% of obligations can be from offsets of which up to 2% may come from REDD[2] programs	Reduced Cap 50% IAF All allocations continue to be based on carbon-weighted barrel approach Fuels under the cap continues to stay in effect No penalty for excess allocated credits; no recalculation of allowances Up to 8% of obligations can be from offsets of which up to 4% may come from REDD[2] programs

Mild impact Significant impact Severe impact

1. Solomon Energy Intensity Index; 2. Reducing Emissions from Deforestation and Forest Degradation (REDD) 3. The carbon-weighted barrel approach specifies a benchmark of emissions for each barrel of throughput for each process and sums up the total to get the refinery' predicted emissions
Source: CARB

Exhibit 4

Total refining sector allocation

Allocation of allowances to the total refining sector is calculated based on total barrels of output

Refineries without a Solomon EII index receive allowances first

Each refinery without a Solomon EII index receives allowances based on either barrels of output or adjusted average annual GHG emissions, whichever is less

Refineries with Solomon EII indices

Remaining allowances are distributed among refineries with Solomon EII indices based on adjusted historic emissions

Distribution factor takes into account Solomon EII index to distribute more credits to more efficient refineries

Weighting function

Weighting function reduces or increases spread of distribution factor based on differences in efficiency among refineries

As ratio of the average EII to the best EII in the group increases, differences in distribution factor decrease

Source: CARB

Exhibit 5

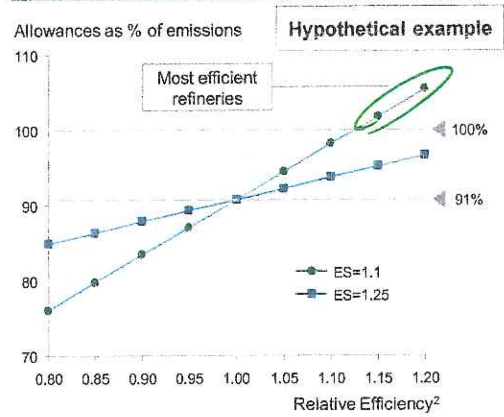
Differences from average driven by differences in efficiency amongst the Solomon EII refinery group

The average refinery will receive 85-90% of the required allowances in 2013 (assuming 5% reduction in emissions from energy efficiency projects), and this will become more onerous for refineries as time goes on

More efficient refineries, as measured by relative efficiency vs the group, will always receive a greater share of allowances

The distribution of no-cost allowances among refineries becomes narrower when the Efficiency Spread[1] (ES) between the average refinery and best refinery increases

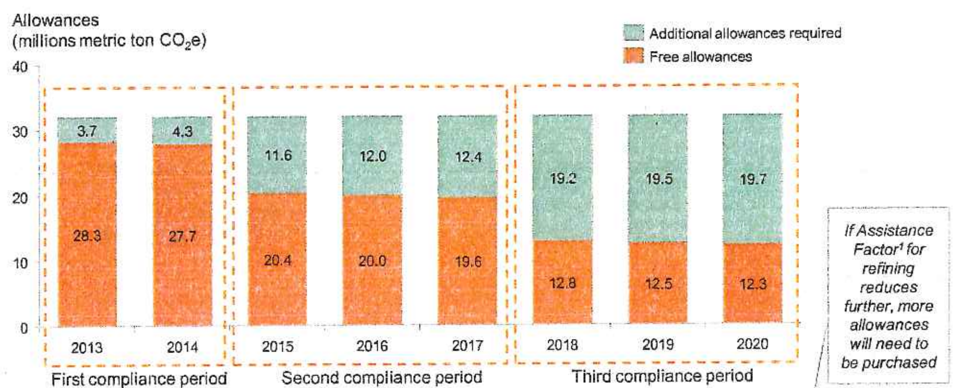
Efficient refiners can receive surplus allowances when ES is low



1.Measured as ratio of weighted average EII value in group to best EII value in group 2.Measured as ratio of average EII value in group to refinery's EII value
Note: Assumes allocations to EII group are 92.5% of the group's baseline emissions. Values calculated for 2013
Source: CARB, BCG analysis

Exhibit 6

Scenario where refiners remain at 2012 level of emissions (32MM metric tons) till 2020



	2013	2014	2015	2016	2017	2018	2019	2020
Y-o-Y Cap decrease (%)	1.9	1.8	2.0	2.0	1.9	2.1	2.1	2.1
Industry Assistance Factor	100%	100%	75%	75%	75%	50%	50%	50%

1. Industry Assistance Factor will determine number of free allowances that are allocated to each industry
Note: 2012 cap is set at Business As Usual (BAU) emissions for that year. Assumed that 2012 emissions for refineries is at the 2010 emissions level reported to the CARB by refineries
Source: AB 32 Proposed Regulation Order; BCG analysis; 2010 CARB emissions reports

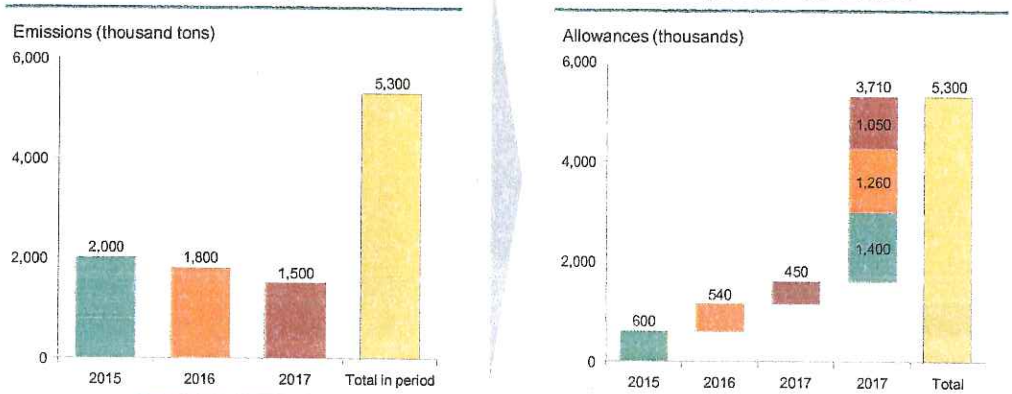
Exhibit 7

Example: Refiner generating 2M, 1.8M, and 1.5M tons of CO2 emissions in 2015, 2016, and 2017, respectively

Hypothetical example

Emissions from a capped source

Allowances that need to be surrendered each year for the source

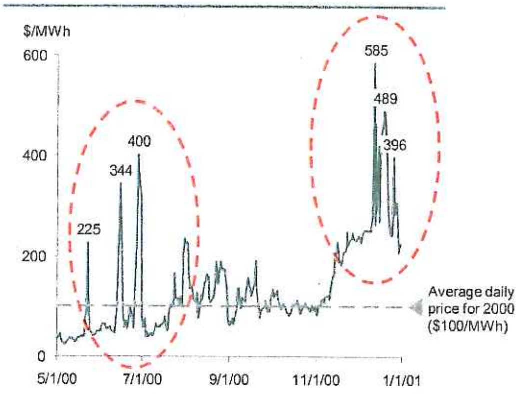


Three-year compliance period provides companies with flexibility and lead time to meet compliance obligations

Source: CARB; BCG analysis

Exhibit 8

California electricity prices (May – Dec 2000)



Cost of carbon could see similar volatility

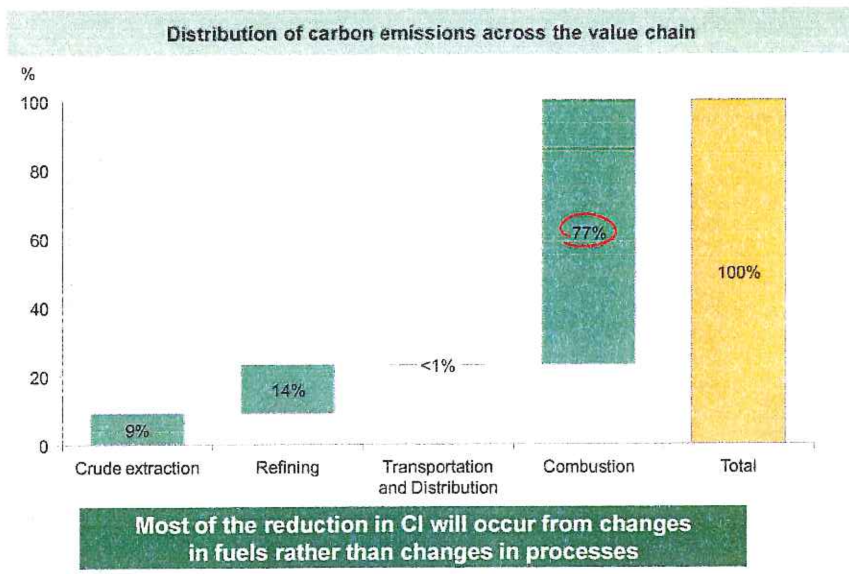
Spikes in California electricity prices were caused my market uncertainty and speculation

As the carbon market develops, uncertainty will decrease; however, uncertainty will exist at the outset

Thomson Reuters has forecasted carbon prices of $30-35/ton; however, in order to account for a 4-5x spike in carbon prices, similar to electricity prices in the analog, we considered carbon costs of up to $150/ton as an unlikely but plausible scenario

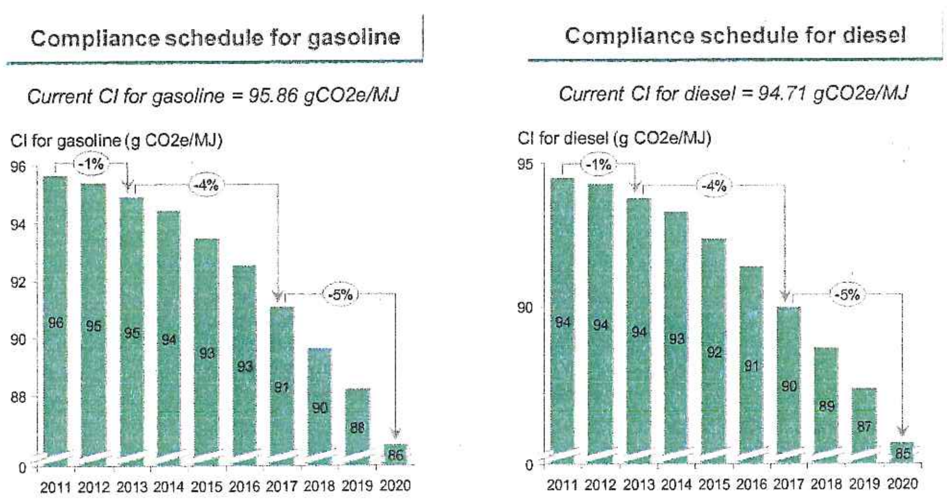
Source: PowerDAT NP15 prices, BCG analysis, Thomson Reuters

Exhibit 9



Source: CARB website; BCG analysis

Exhibit 10

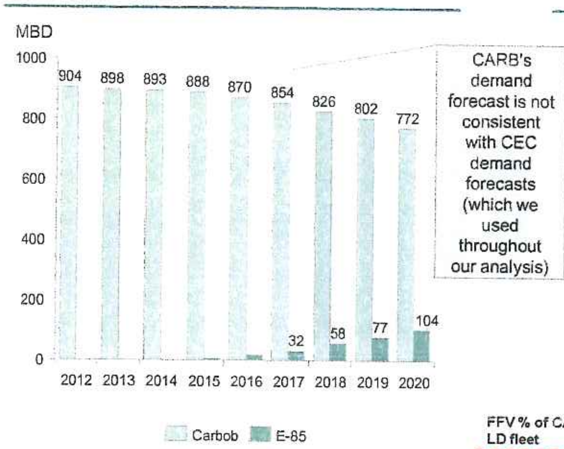


Source: CARB; BCG analysis

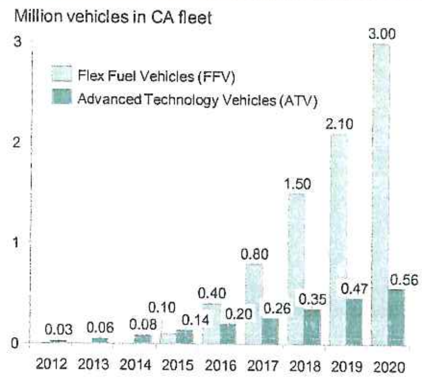
Exhibit 11

CARB LCFS Scenario 1

CARBOB substitution with Ethanol



Increase in alternative fuel vehicles



	2012	2013	2014	2015	2016	2017	2018	2019	2020
FFV % of CA LD fleet	0.0%	0.0%	0.0%	0.4%	1.6%	3.1%	5.6%	7.5%	10.2%
ATV % of CA LD fleet	0.1%	0.2%	0.4%	0.6%	0.8%	1.0%	1.3%	1.7%	1.9%

ATV volume ramp up to 560K is challenging by 2020

1. Advanced Technology Vehicles (ATVs), include Plug-in Hybrid Electric Vehicles (PHEV), Battery Electric Vehicles (BEV), and Fuel Cell Vehicles (FCV)

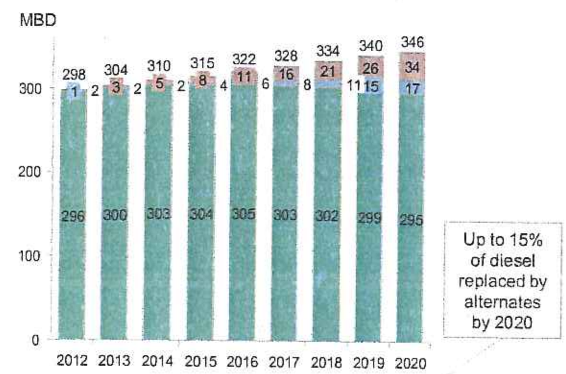
Notes: Full description of scenario available at table E-1a, page E-5

Source: CARB; BCG analysis

Exhibit 12

CARB LCFS Scenario 7

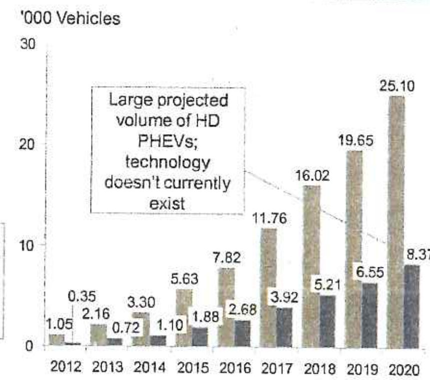
Diesel substitution to meet compliance



% sub	0.8	1.5	2.2	3.7	5.1	7.4	9.6	12.2	14.9

Adv. Renew. Diesel · Conv. Biodiesel · Hydrocarbon Diesel

Increase in alternative fuel vehicles



	2012	2013	2014	2015	2016	2017	2018	2019	2020
CNG % of CA HD fleet	0.2	0.3	0.5	0.8	1.1	1.7	2.0	2.4	3.0
PHEV[1] % of CA HD fleet	0.1	0.1	0.1	0.2	0.3	0.5	0.6	0.8	1.0

Heavy Duty CNG · Heavy Duty PHEV

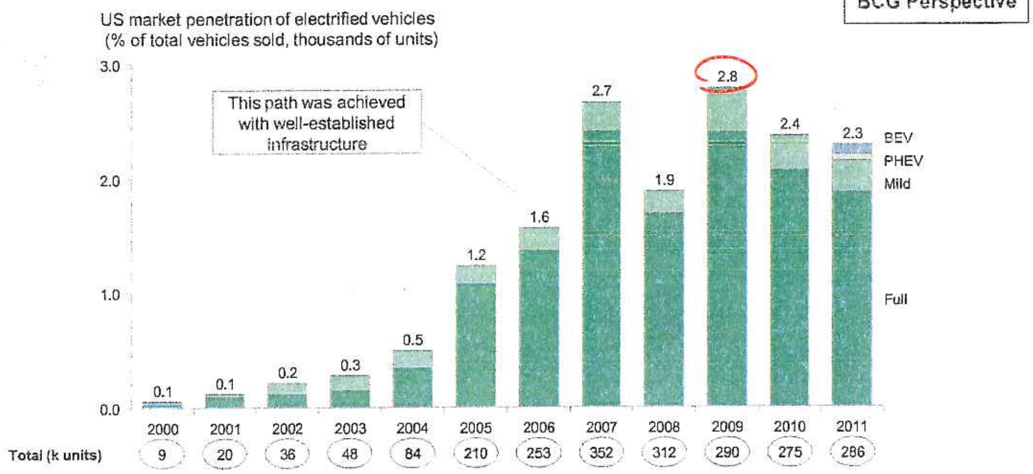
1. Plug-in Hybrid, Electric Vehicle

Notes: Full description of scenario available at table E-8a pg E-12

Source: CARB, BCG analysis

Exhibit 13

BCG Perspective



Hydrogen vehicles will take much longer to penetrate market than the average 7-8 year fleet turnover rate for cars

Note: hybrid classification based on Global Insight definitions. Full hybrid: hybrid vehicles that can accelerate the vehicle through electric power only; Mild hybrids: hybrid vehicles where the electric motor can only assist the combustion engine to power the wheels, but can not move the vehicle by itself. Micro hybrids (start-stop only hybrids) excluded from analysis; PHEV: Plug-in Hybrid Electric Vehicle, unlike full and mild hybrids, is not dependent on a combustion engine for reasonable ranges; BEV: Battery electric vehicle, has no combustion engine
Source: US Department of Energy, Global Insight, HybridCars.com, Auto News, BCG analysis

Exhibit 14

Scenario if LCFS compliance is achieved solely through blending low CI blendstocks (e.g., sugarcane ethanol)

Model assumptions

No widespread adoption of low CI vehicles[1] by 2020, which would require:

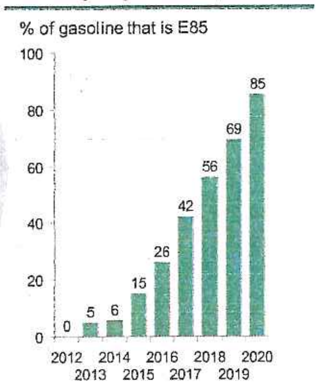
- Faster consumer uptake than historical hybrid uptake
- Significant technological advances
- Brand-new infrastructure network

Volume of sugarcane ethanol reaches 65% of total ethanol volume by 2014

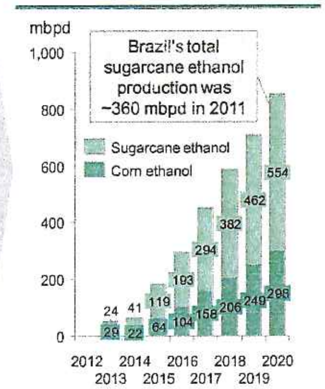
The standard mixture for ethanol in gasoline goes from 10% (E10) to 12% (E12) by 2015

Brazilian ethanol replacing domestic ethanol would cost an additional 5-10 cpg (of ethanol).[2]

LCFS targets will require majority E85 adoption



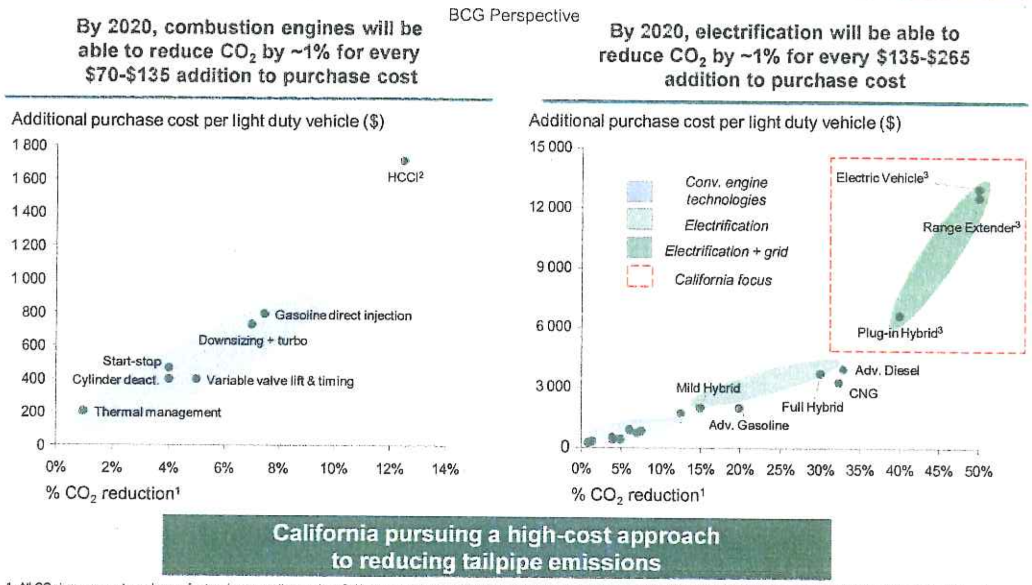
LCFS targets would require 554 mbpd of cane ethanol



Projected ethanol adoption would also require rapid development of shipping and transport infrastructure

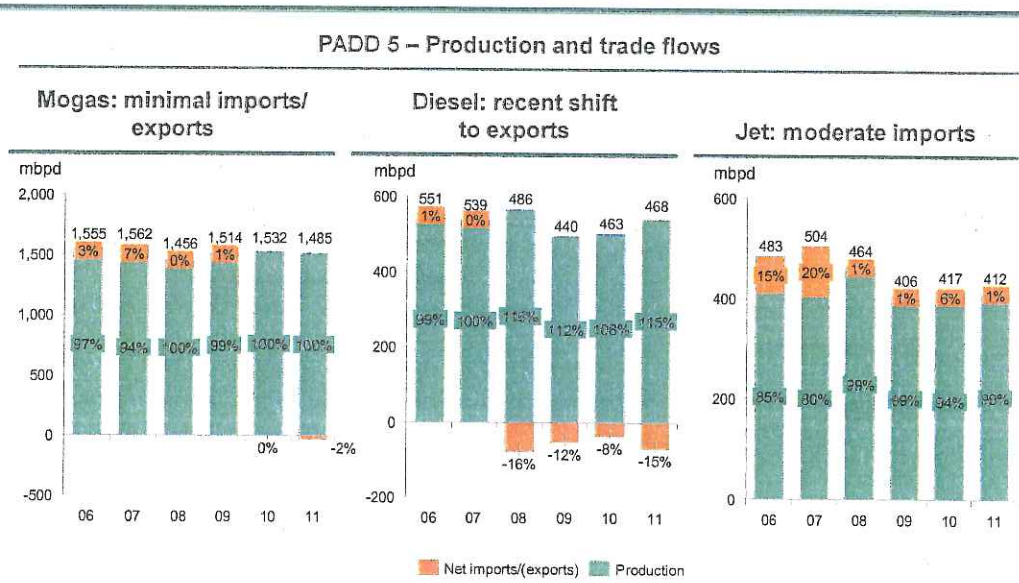
1. Powered by renewable electricity, low CI hydrogen, or CNG
2. Assuming no infrastructure constraints, given current prices of ethanol delivered from Chicago, ethanol spot prices in Brazil, and estimated transport from Brazil.
Source: CARB, Bloomberg, BCG analysis, Renewable Fuels Association

Exhibit 15



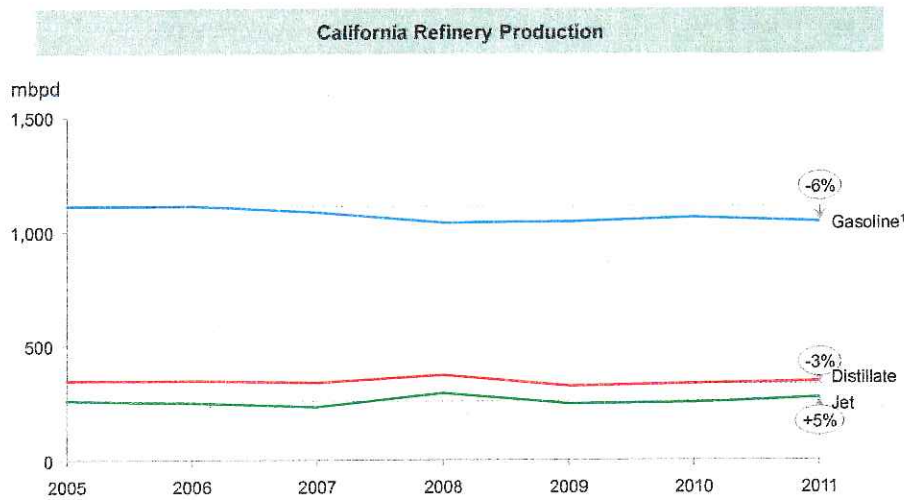
1. All CO_2 improvement numbers refer to a base gasoline engine; 2. Homogeneous Charge Compression Ignition, uses compression ignition for a gasoline fuel 3. Calculated with 586 g/kWh carbon intensity of power generation
Source: "The Comeback of the Electric Car" BCG report, expert interviews including original equipment manufacturers and other suppliers

Exhibit 16



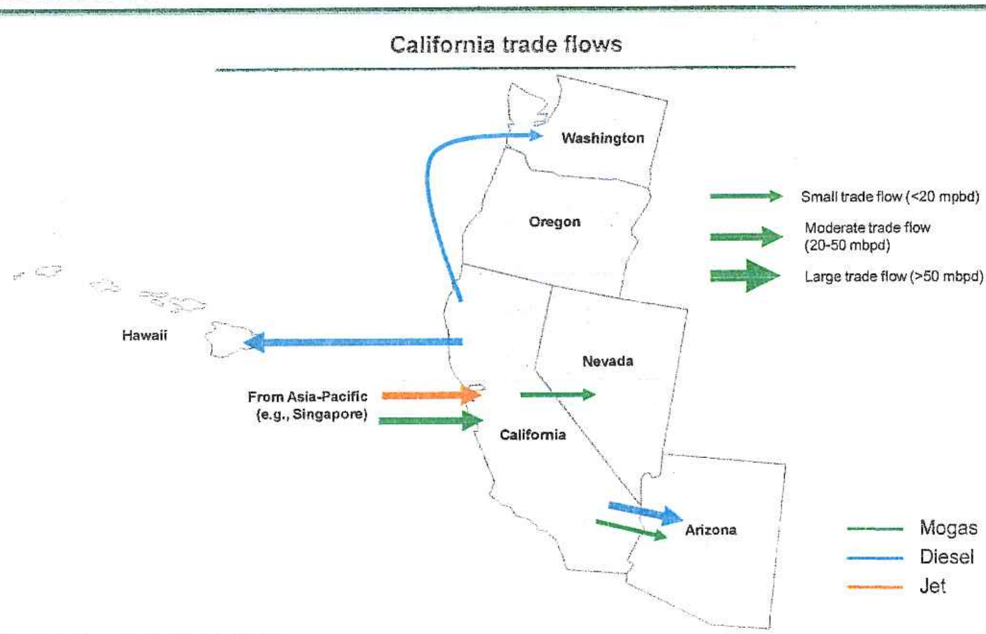
Note: Includes gasoline blending components and finished products
Source: EIA; BCG analysis

Exhibit 17



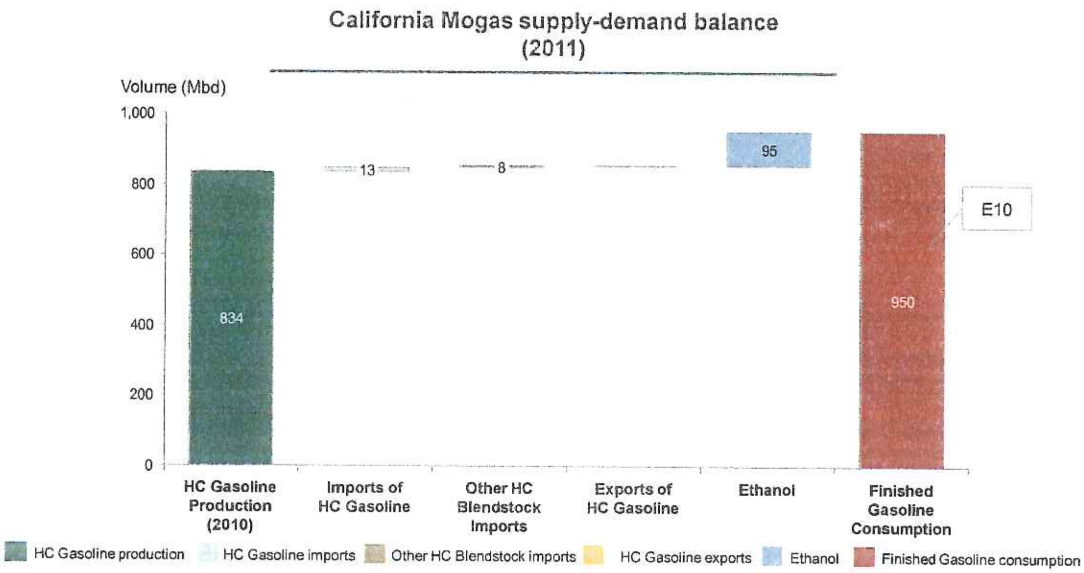
1. Includes gasoline blending components and finished products
Source: California Energy Commission; BCG analysis

Exhibit 18



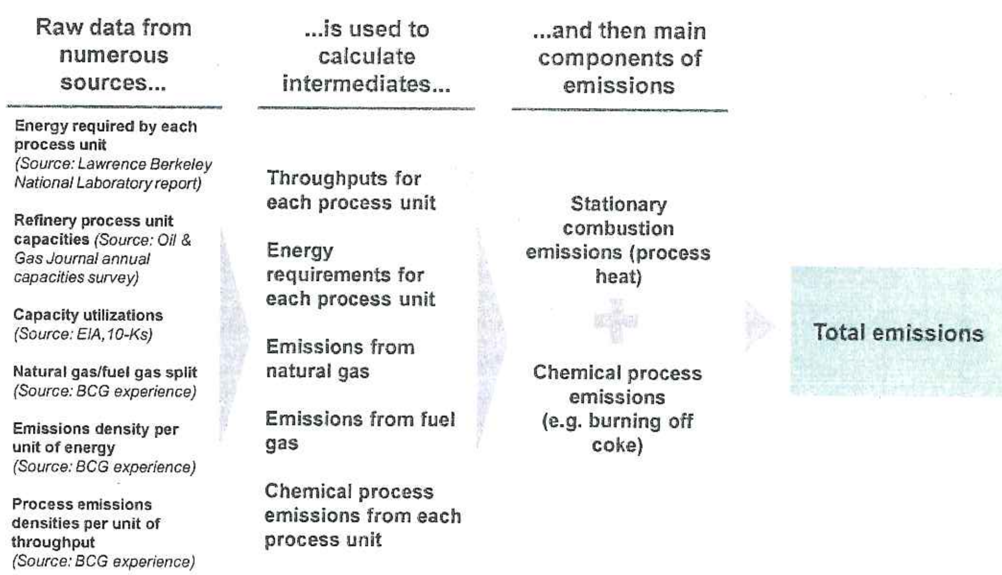
Source: FERC Form 6; EIA; Lit search; BCG experience

Exhibit 19



Source: CEC demand forecasts, BCG analysis

Exhibit 20



Source: BCG analysis

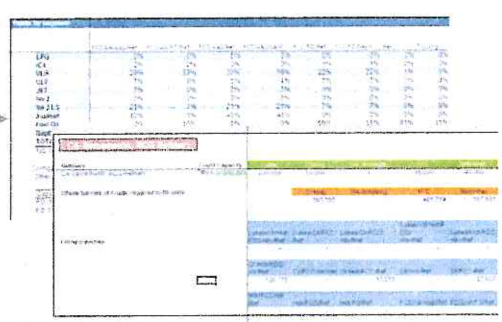
Exhibit 21

1. **Evaluate AB 32 impact on demand destruction for fuels (gasoline, diesel, jet)**
   - Determine impact of alternative vehicles
   - Utilize ethanol blending to reach LCFS compliance
   - Revise product demand forecasts
2. **Establish supply/demand mechanisms & refinery economics**
   - Model operating and financial parameters of all PADD V refineries
   - Create regional supply/demand matrix for potential mogas and diesel outlets
   - Include impact of AB 32 compliance
3. **Financially challenged refineries sequentially cease production**
   - Assume refineries with sufficiently negative cash flow would cease production
   - Re-evaluate supply/ demand balance
   - Determine new regional supply/demand balance
4. **Determine PADD V refining capacity at equilibrium**
   - Validate that refineries that have ceased production remain non-producing at new market equilibrium
   - Construct new "industry health" matrix
5. **Conduct sensitivity analyses to test breakpoints**
   - Use 2017 equilibrium posture as baseline
   - Model impact of change in cost of carbon and narrow L/H differentials

Exhibit 22

BCG refinery economics model

Inputs:
- Crude prices
- Refinery operating costs
- Crude slate
- Refinery operating parameters
- Refinery process unit capacities

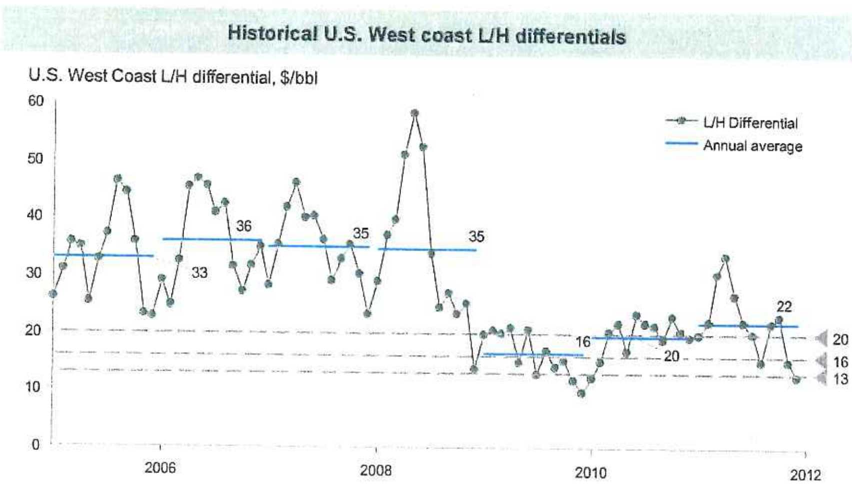


Key output

- Volume of crude run by refiners
- Runs by segment[1] by refinery
- Key refinery constraints
- Volume of product for each refinery
- Variable margin and cash flow for each refinery
- Overall market supply and economics

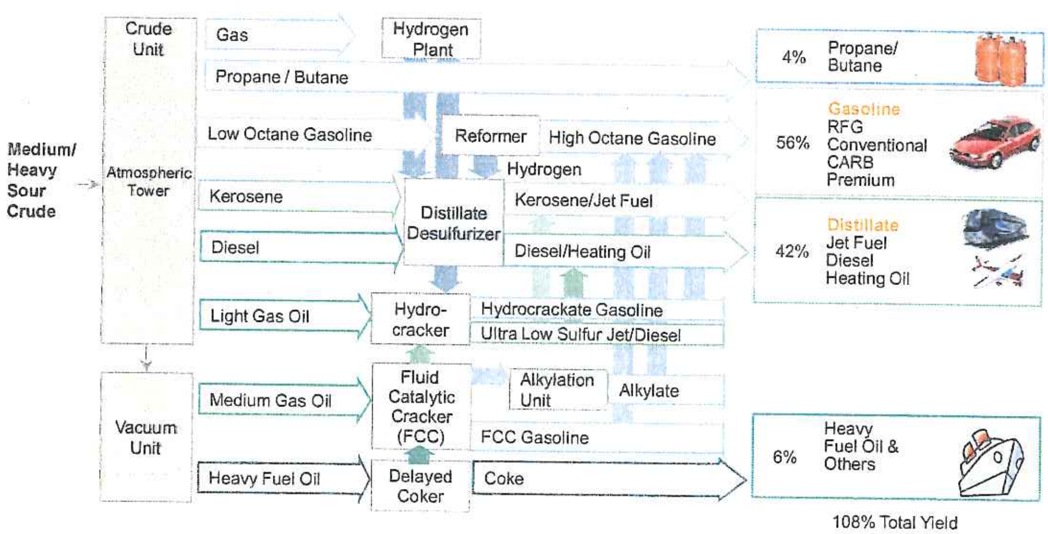
1. Segment refers to a configuration that a whole barrel of crude runs through in a refinery to yield petroleum products.
Source: BCG Segmentation Model; BCG analysis

Exhibit 23



Notes: Uses LA CARBOB, CARB Diesel and LA HSFO cost to calculate light-heavy differential (ULR+CARB Diesel)/2) – HSFO
Source: Bloomberg; BCG analysis

Exhibit 24



Source: Lit search

Exhibit 25

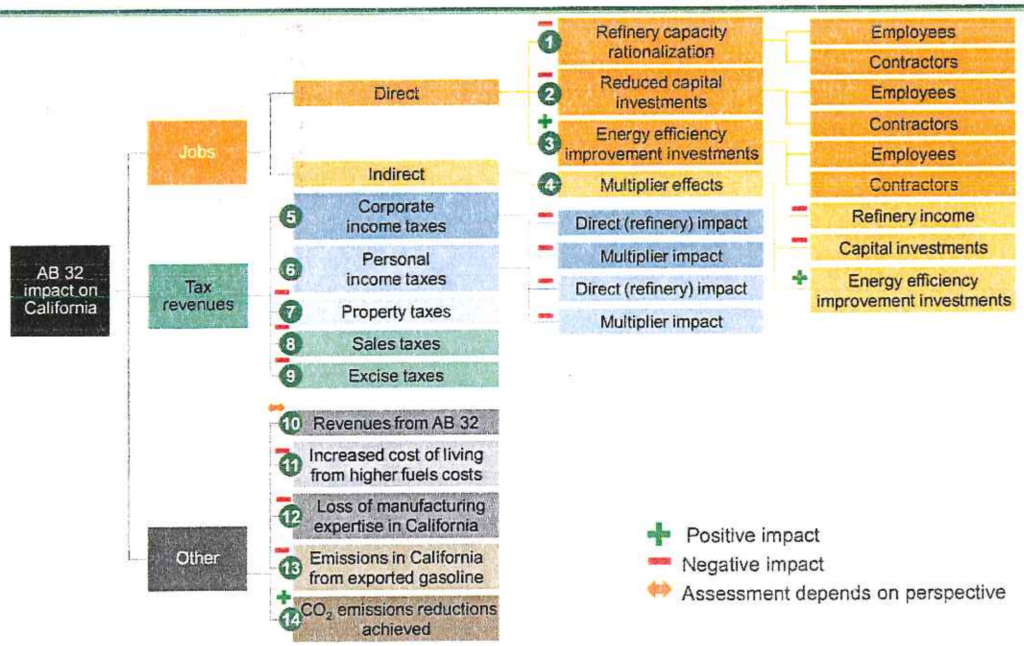
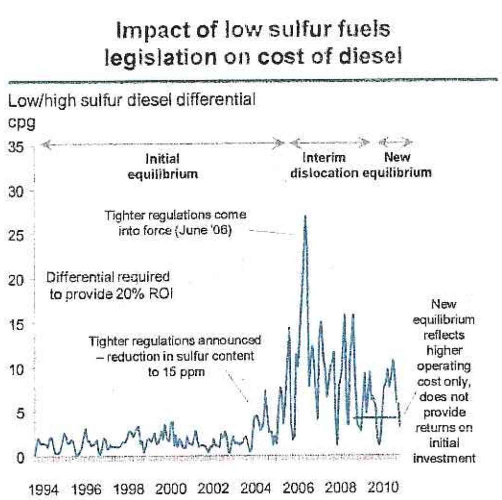
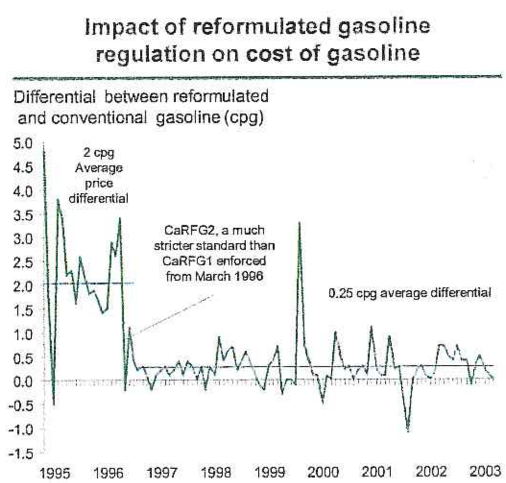


Exhibit 26





Source: New York Harbor NYMEX, EIA; BCG analysis

Exhibit 27

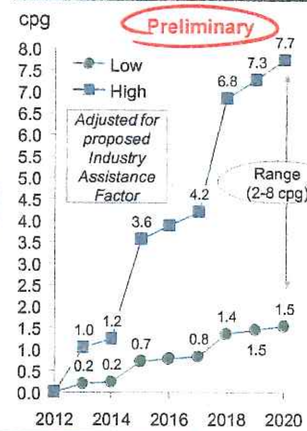
Model assumptions

- Refinery production constant from 2012 to 2020
- Refinery emissions are constant from 2009 to 2020
- Industry Assistance Factor of 100% in the first period, 75% in the second period, and 50% in the third period
- Compliance achieved exclusively through purchase of allowances
- Excludes impact of inflation

Compliance cost per CARB regulations

Year	General allowance price ($/ metric ton)	Max reserve allowance price ($/ metric ton)
2013	10.0	50.0
2014	10.5	52.5
2015	11.0	55.1
2016	11.6	57.9
2017	12.2	60.8
2018	12.8	63.8
2019	13.4	67.0
2020	14.1	70.4

Amount of cost recovery required by industry to meet CA fuel demand



Refiners/importers have three options for compliance: **1. Buy allowances from the general auction, 2. Buy allowances from the reserve auction, or 3. Buy allowances from other business on ICE.** The demand for CCAs is expected to increase significantly in 2015, resulting in CCA costs on ICE possibly exceeding the reserve auction ceiling.

Source: CARB, California Energy Commission; BCG analysis

Exhibit 28

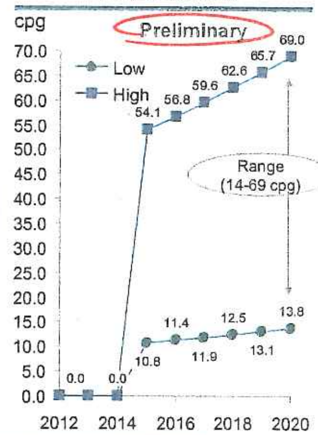
Model assumptions

- Refinery production constant from 2012 to 2020
- Fuels under the cap goes into effect in 2015
- Refineries are charged for full combustion of all fuels produced
- No industry assistance; compliance achieved exclusively though purchase of allowances
- Excludes impact of inflation

Compliance cost per CARB regulations

Year	General allowance price ($/ metric ton)	Max reserve allowance price ($/ metric ton)
2013	10.0	50.0
2014	10.5	52.5
2015	11.0	55.1
2016	11.6	57.9
2017	12.2	60.8
2018	12.8	63.8
2019	13.4	67.0
2020	14.1	70.4

Amount of cost recovery required by industry to meet CA fuel demand

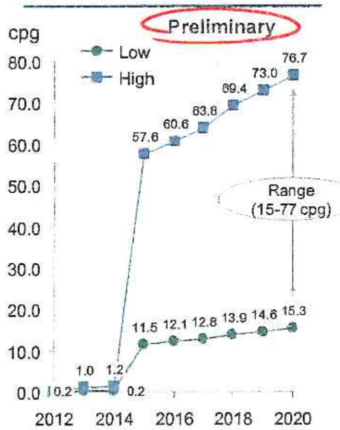


Refiners/importers have three options for compliance: **1. Buy allowances from the general auction, 2. Buy allowances from the reserve auction, or 3. Buy allowances from other business on ICE.** The demand for CCAs is expected to increase significantly in 2015, resulting in CCA costs on ICE possibly exceeding the reserve auction ceiling.

Source: CARB, California Energy Commission; BCG analysis

Exhibit 29

Amount of cost recovery required by industry to meet CA fuel demand



Compliance cost could be much higher

High end of range based on maximum reserve auction cost set by CARB

Reserve auction only allocated set amount of credits each year; once that is exhausted, allowances must be bought in the market

Market costs determined by supply/demand –can exceed maximum reserve cost ("soft collar" set by CARB)

No mechanism to adjust availability of allowances for economic conditions, a key determinant of emissions

Volatility will be high until market matures

In early phases of CCA market development, liquidity is likely to be low, and cost of CCAs will not be well established

This could result in high volatility until market matures

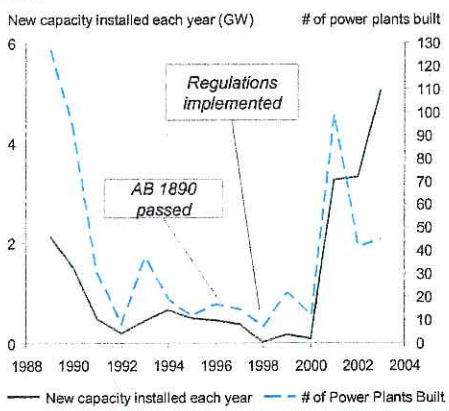
Carbon "shocks" from sudden increases in compliance costs could affect consumers and businesses

Resulting uncertainty could discourage companies from investing in emissions-reduction projects

Source: CARB, California Energy Commission, BCG analysis

Exhibit 30

California investment in new power generation plummeted in 1990s



Regulatory uncertainty in California prevented investment in power

In 1996, California passed AB 1890, resulting in significant change to regulatory environment of power industry to be implemented in 1998

Uncertainty in the regulatory environment prevented companies from being able to calculate return on investment

Given the uncertainty investments were delayed resulting in a demand crisis; investments took years to come on-line

Large increase in new plants and installed capacity in 2000s to satisfy pent-up demand

LCFS legal issues likely to delay new transport fuels related investments

Source: Thomson Reuters

Exhibit 31

Reduced demand for refined products	Reduced demand for HCG driven by increased volume of fuel efficient cars Zero demand for refined products for BEVs and FCVs; PHEVs will have hugely reduced demand
Mass market adoption of ZEVs is questionable	Compliance for manufacturers is measured based on the number of cars manufactured and delivered and not on the number of cars purchased BCG estimates a 15 year payback period for an electric vehicle vs. consumer expectations of ~3 years
Heightens CFO requirements	ZEV standards will result in more hydrogen FCVs, accelerating the CFO mandates and raising the required number of outlets

Source: BCG analysis

Exhibit 32

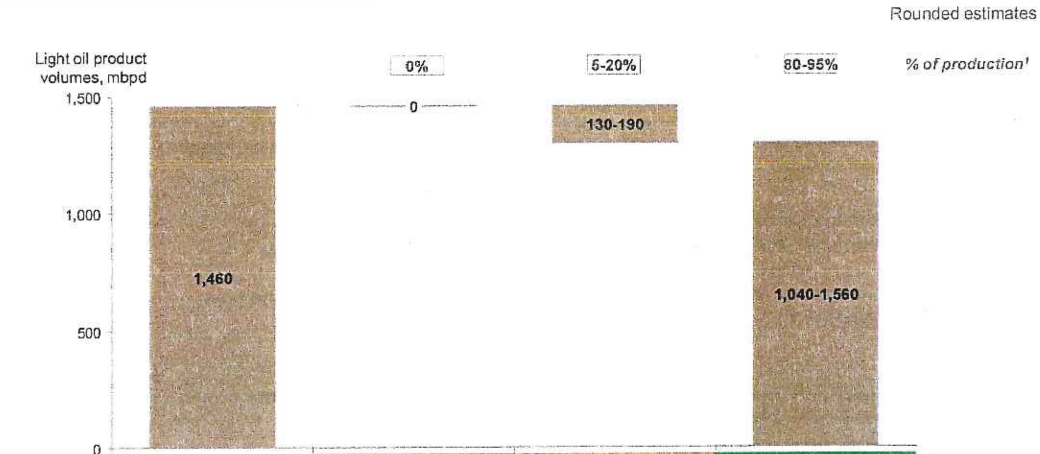
Evaluate refinery health

- **For each scenario (starting with the status quo), the BCG refinery economics model estimated cash flow by refinery**
- **Refineries with sufficiently negative cash flow in a given scenario are expected to cease production**

Distressed	Refineries classified as "distressed" typically generate negative free cash flow of $30 million/year or worse. Refineries in this category are expected to cease production
May survive	Refineries classified as "may survive" typically have free cash flow of less than $30 million/year. Refineries in this category would continue producing, but would be at risk of ceasing production if the economic outlook deteriorates
Will survive	Refineries classified as "will survive" are the strongest performers in the region and have significant positive free cash flow, usually in excess of $30 million/year. Refineries in this category would continue to produce and have the ability to withstand temporary economic downturns

Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

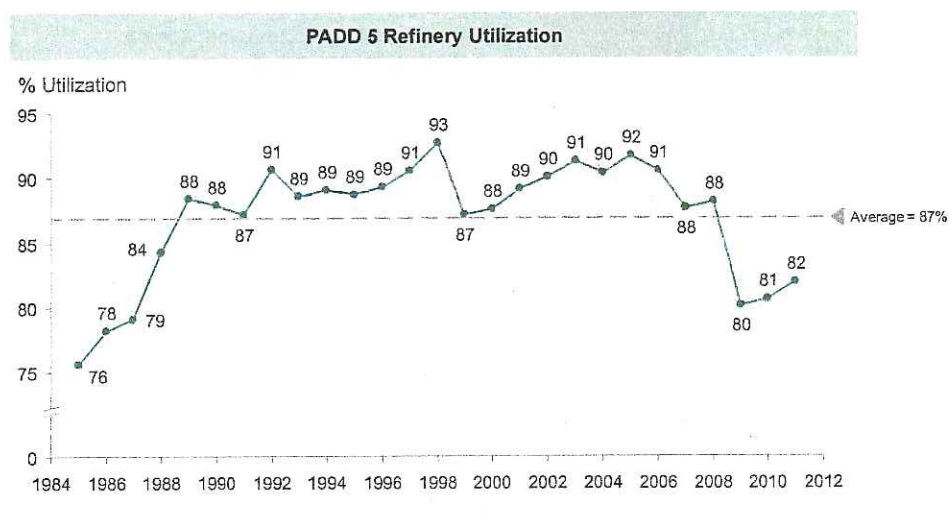
Exhibit 33



	Total	Distressed	May survive	Will survive
Crude capacity (MMBD)	2.0	0 (0%)	0.2 – 0.4 (10 - 20%)	1.6 - 1.8 (80 - 90%)
Number of CA refineries	14	0	3 - 5	9 - 11

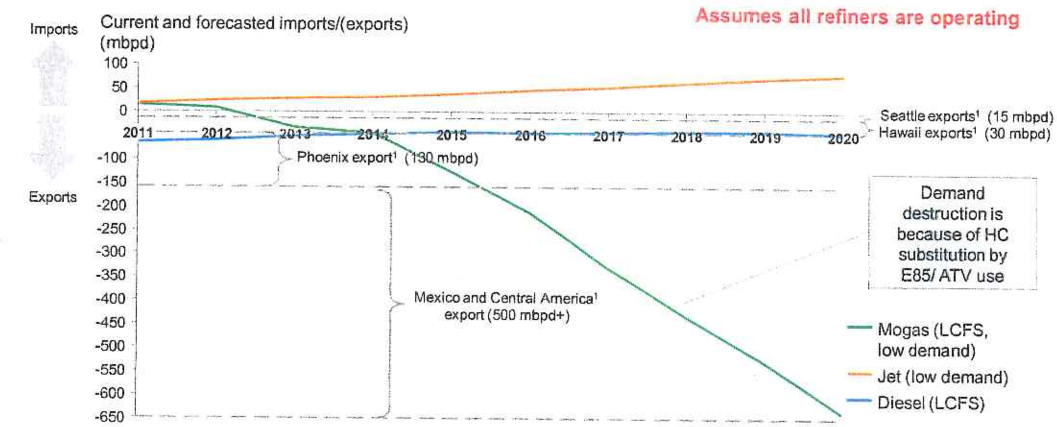
1. Assuming 82% utilization for all refineries
Note: Assumes $110 crude cost and $25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

Exhibit 34



Source: EIA

Exhibit 35

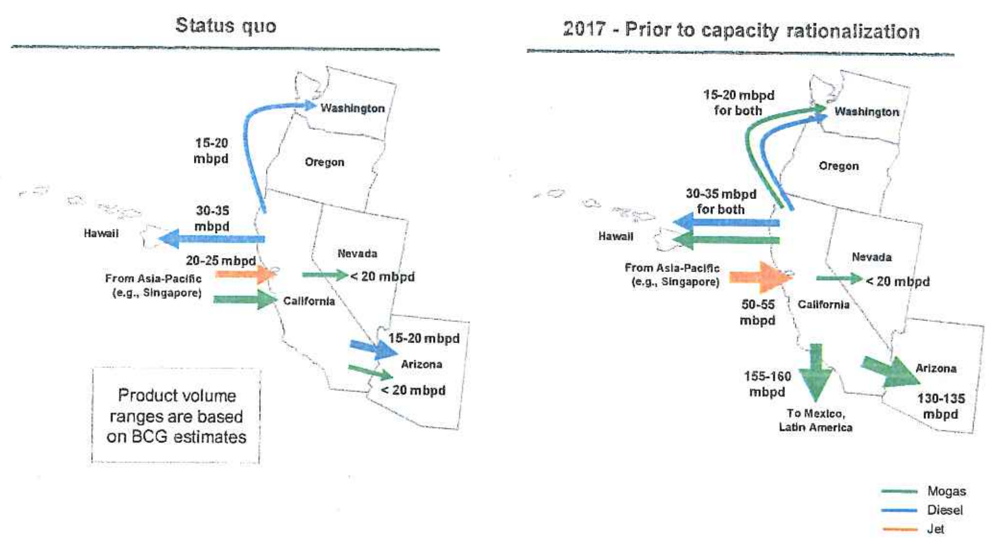


Net trade (mbpd)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Δ ('20-'11)
			1st compliance period		2nd compliance period			3rd compliance period			
Mogas	13	7	(34)	(45)	(128)	(215)	(330)	(434)	(529)	(639)	(652)
Jet	15	22	28	30	36	45	52	61	70	78	63
Diesel	(67)	(62)	(53)	(48)	(43)	(46)	(45)	(42)	(42)	(46)	21

Import / Export

1. Based on current market conditions, which could change, but have not changed significantly historically;
High demand scenario also results in export by 2017 with LCFS
Source: CEC demand forecasts; BCG analysis

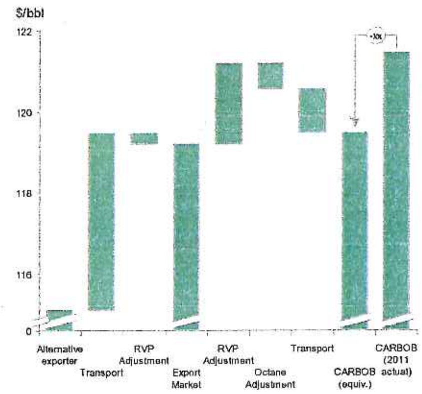
Exhibit 36



Source: FERC Form 6; EIA; Lit search; BCG experience

Exhibit 37

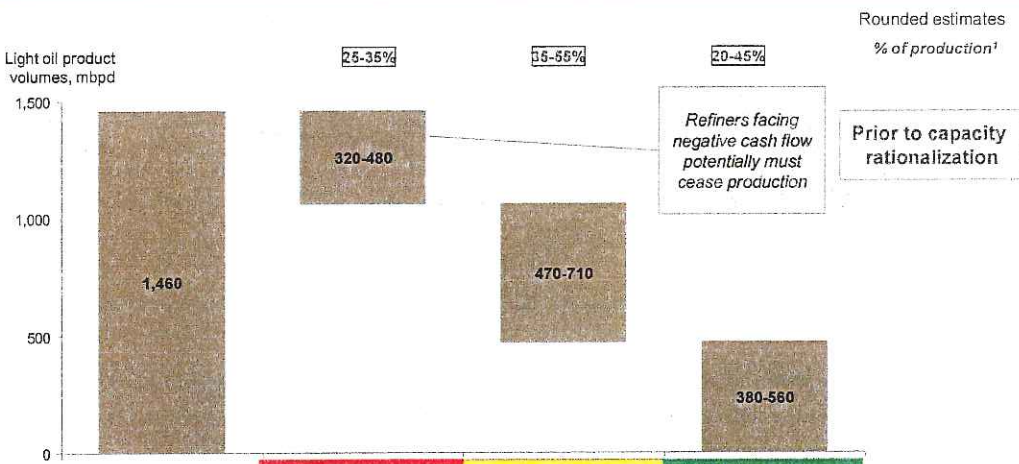
Methodology to establish market attractiveness



Source: Kinder Morgan, Magellan, ASTM, Bloomberg, CARB, BCG analysis

Mogas export market by order of attractiveness	Available volume (mbpd)
Seattle	13
Hawaii	30
Phoenix	130
Mexico and Central America	500+

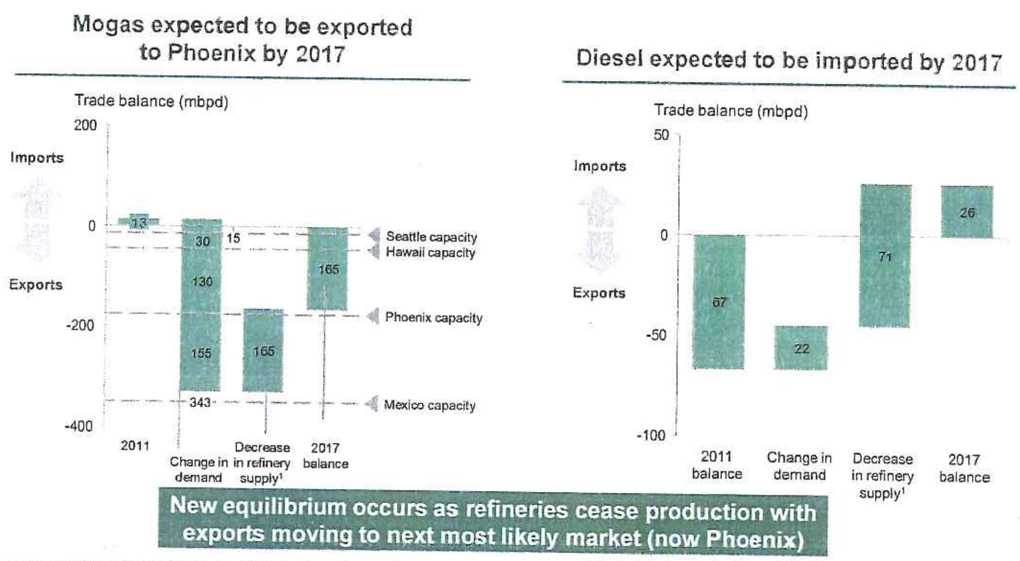
Exhibit 38



	Total	Distressed	May survive	Will survive
Crude capacity (MMBD)	2.0	0.5 – 0.7 (25 - 35%)	0.7 – 0.9 (35 - 45%)	0.5 – 0.7 (25 - 35%)
Number of CA refineries	14	5 - 7	4 - 6	2 - 4

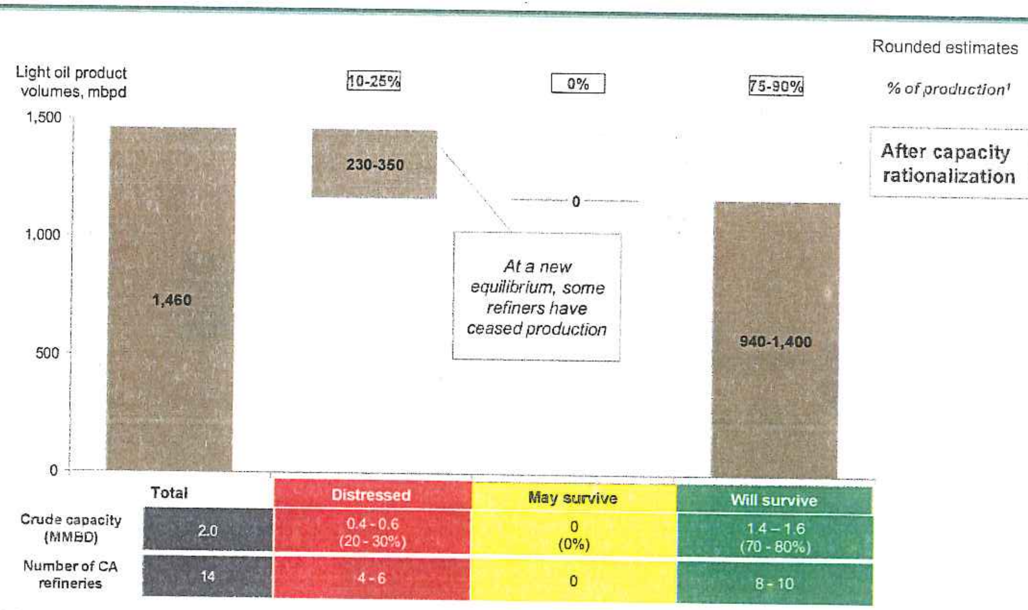
1. Assuming 82% utilization for all refineries
Note: Assumes $110 crude cost and $25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

Exhibit 39



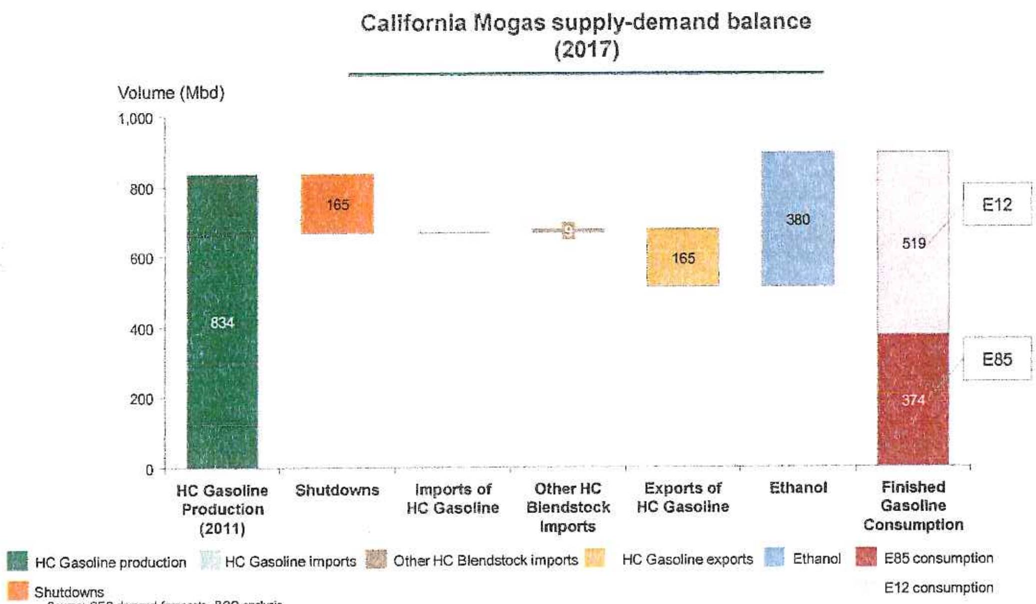
1. It is assumed that refineries will cease production rather than reduce capacity, as capacity reduction would increase pressure from fixed costs
Note: Jet remains on import parity with Singapore in 2017
Source: EIA, CA Energy Commission; CARB reports; BCG analysis

Exhibit 40



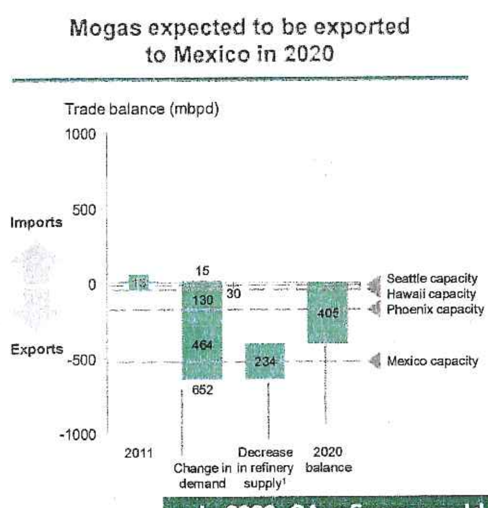
1. Assuming 82% utilization for all refineries
Note: Assumes $110 crude cost and $25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

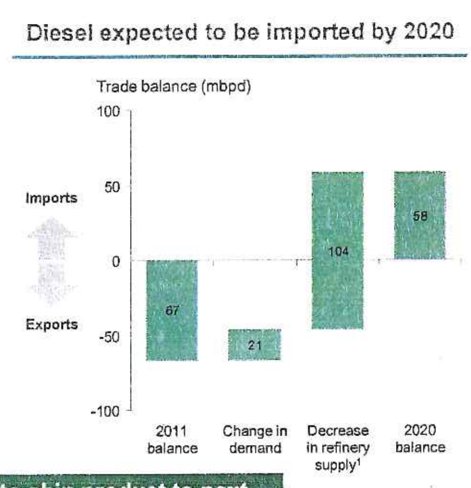
Exhibit 41



Source: CEC demand forecasts, BCG analysis

Exhibit 42

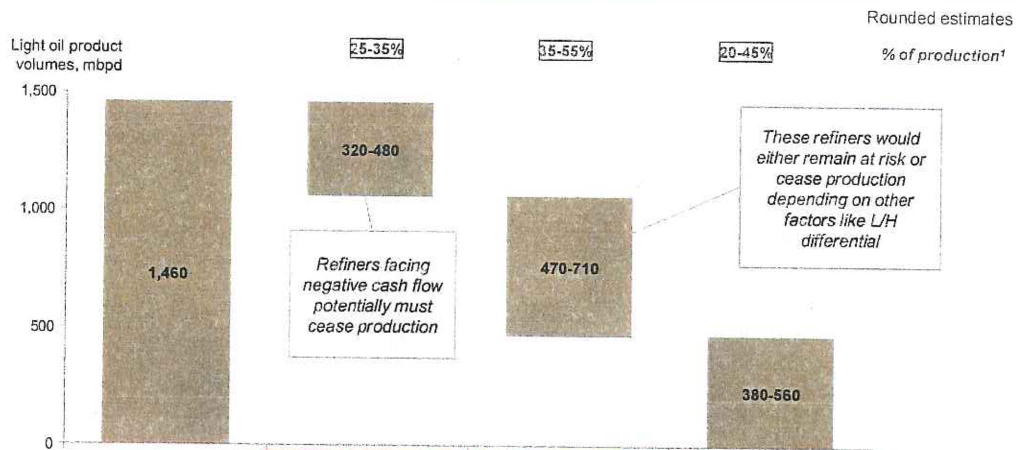




In 2020, CA refiners would have to ship product to next most likely market (now Mexico and Central America)

1. It is assumed that refineries will cease production rather than reduce capacity, as capacity reduction would increase pressure from fixed costs
Note: Jet remains on import parity with Singapore in 2017
Source: EIA, CA Energy Commission, CARB reports, BCG analysis

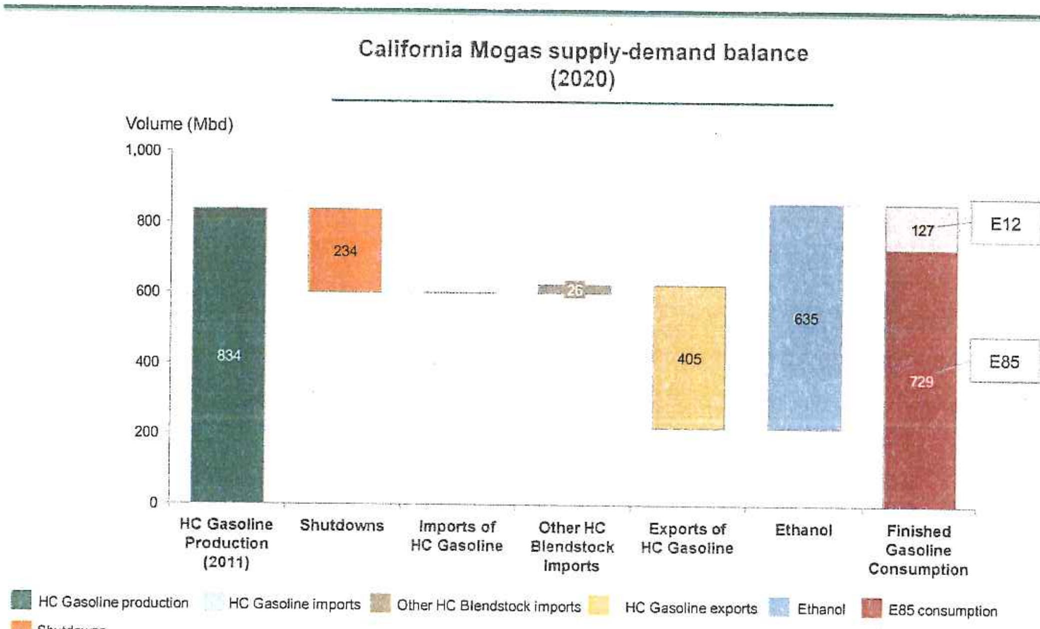
Exhibit 43



	Total	Distressed	May survive	Will survive
Crude capacity (MMBD)	2.0	0.5 – 0.7 (25 - 35%)	0.7 – 0.9 (35 - 45%)	0.5 – 0.7 (25 - 35%)
Number of CA refineries	14	5 - 7	4 - 6	2 - 4

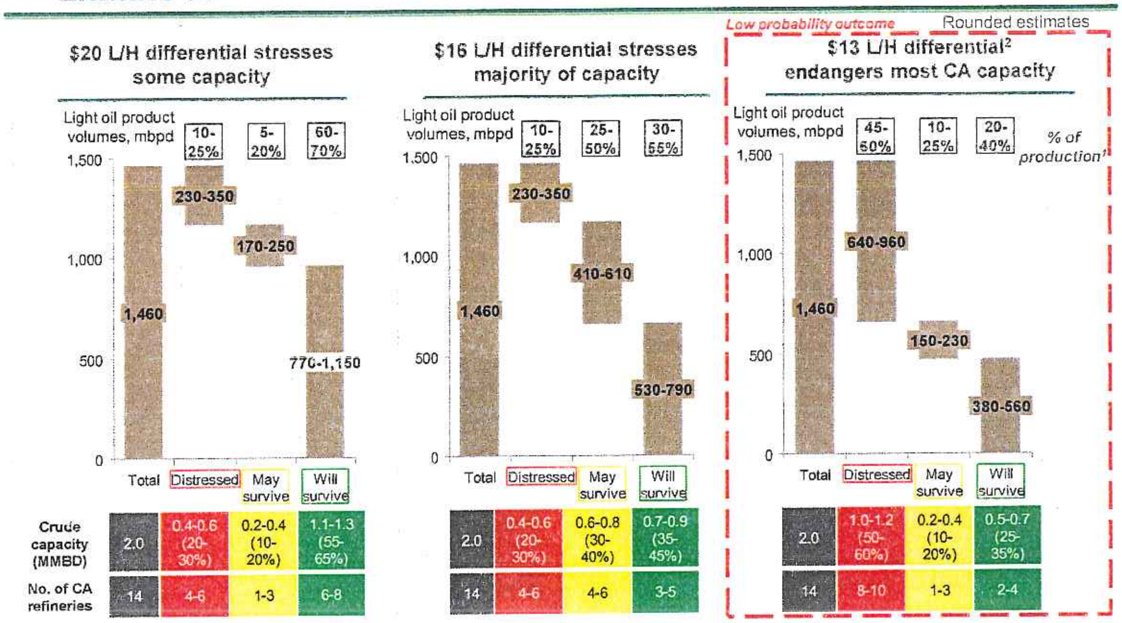
1. Assuming 82% utilization for all refineries
Note: Assumes \$110 crude cost and \$25/bbl L/H differential
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

Exhibit 44



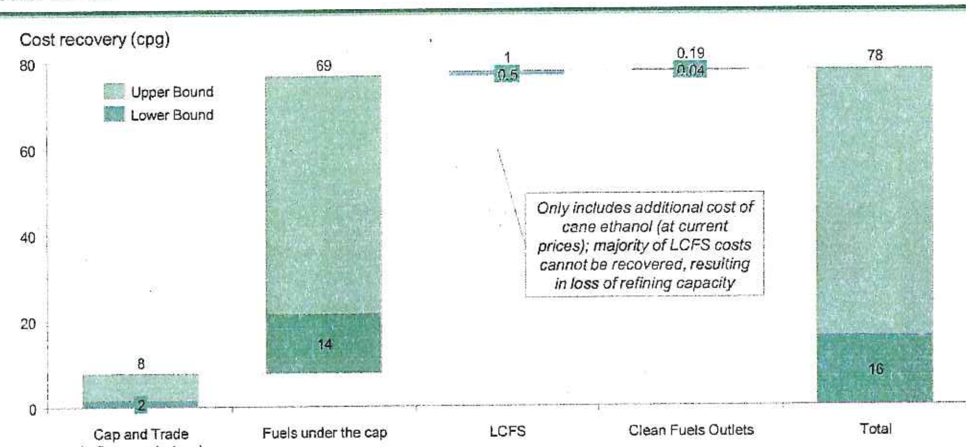
Source: CEC demand forecasts, BCG analysis

Exhibit 45



1. Assuming 82% utilization for all refineries 2. Historical lows Note: Assumes $110 crude cost
Source: Oil & Gas Journal, Bloomberg, BCG economics model, BCG analysis

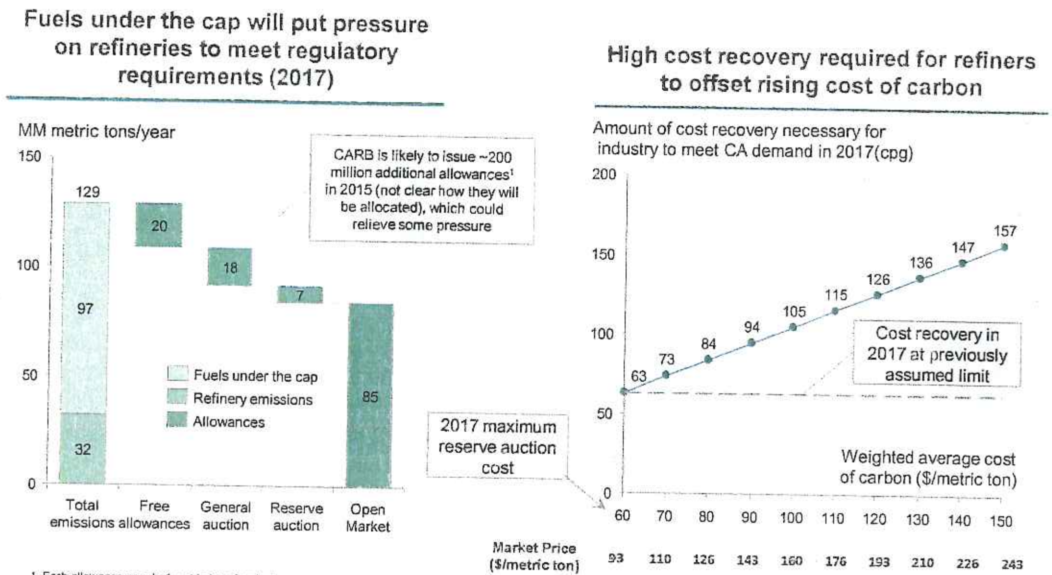
Exhibit 46



	Cap and Trade (refinery emissions)	Fuels under the cap	LCFS	Clean Fuels Outlets	Total
Key assumptions	Refinery emissions constant through 2020	Refinery output constant through 2020	Refinery output and CI constant through 2020	Only cost of capital recovery considered³, WACC= 10%	CCA costs set by general and reserve auctions, not open market (which could be higher)
	Compliance achieved through CCA purchases	Compliance achieved through CCA purchases	Additional cost due to ethanol substitution of cane for corn at current costs	Investments made evenly starting in 2016, 20 year depreciation	
	CCA cost is $14-$70	CCA cost is $14-$70		100-450 outlets constructed at $2MM each	

1. Includes diesel and gasoline 2 One LCFS credit is equal to one metric ton of CO_2e difference from prescribed values
3 Assumes minimal operating cost if co-located with gas station
Source: CARB, Thomson Reuters, BCG analysis

Exhibit 47

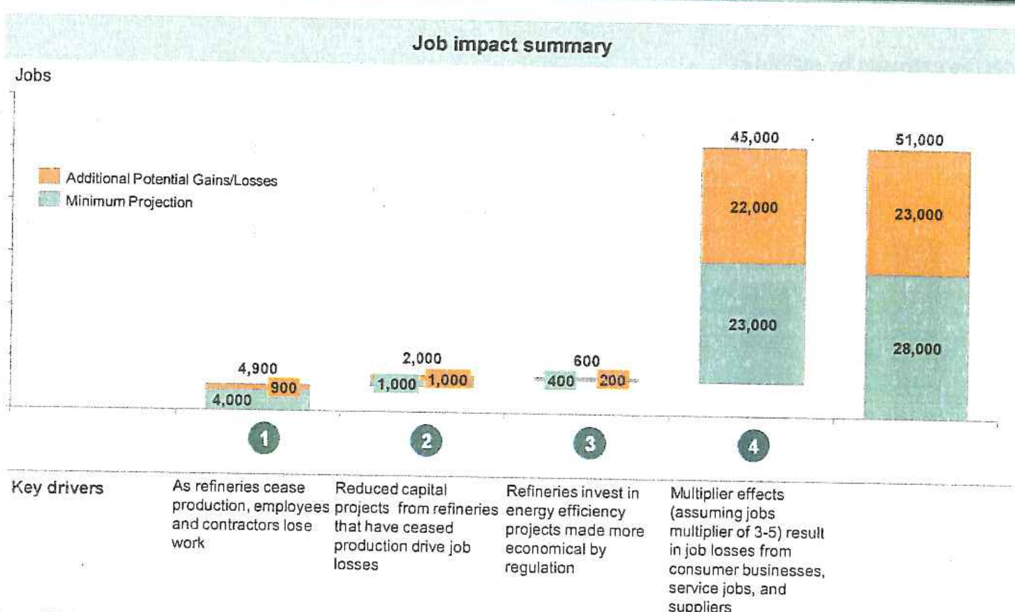


1. Each allowance equals 1 metric ton of emissions

Note: Refineries were assumed to receive their carbon-weighted share of allowances vs the rest of the industry in both auctions

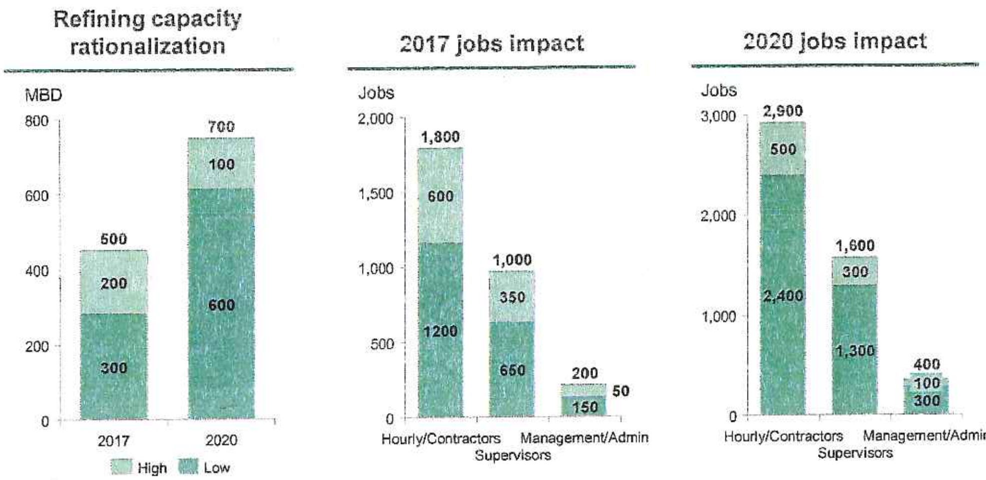
Source: CARB data and estimates; BCG analysis

Exhibit 48



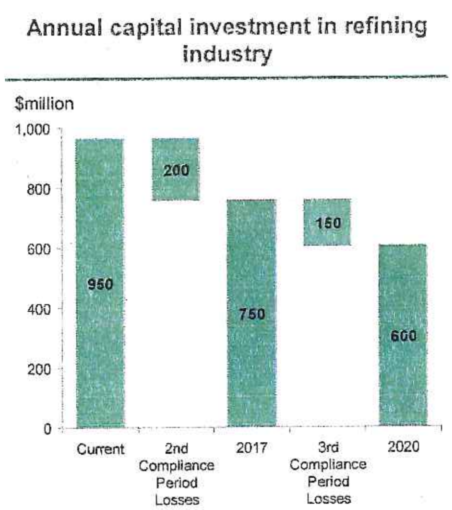
Source: Oil & Gas Journal; BCG experience; BCG analysis; Congressional testimony by Dr. Margo Thorning on 2/9/2011; Fisher International; BEA; Wood Mackenzie, U.S. Census Bureau

Exhibit 49



Note: Job numbers and distribution calculated based on average of second and third quartile Solomon values. Refineries that cease production are assumed to convert to terminals with 2 managers and 18 hourly staff
Source: Oil & Gas Journal, BCG experience, BCG analysis, Solomon

Exhibit 50



Jobs impact

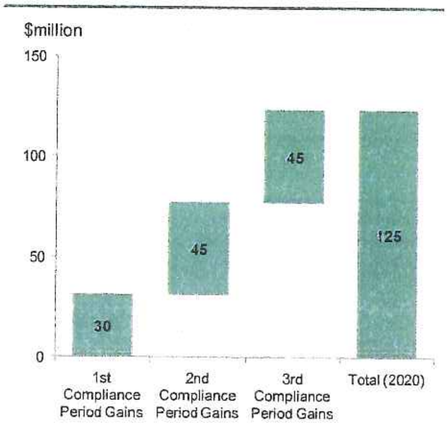
Based on congressional testimony, we estimate one job to be lost for every $200,000-300,000 of reduced capital expenditure

Applying this conversion factor to the capital expenditure lost in the adjoining chart, we estimate 700-1000 jobs could be lost by 2017, and 1,000-2,000 jobs could be lost by 2020

Source: Oil & Gas Journal; BCG experience; BCG analysis; Congressional testimony by Dr. Margo Thorning on 2/9/2011

Exhibit 51

Additional energy efficiency investments in refining industry



Jobs impacted

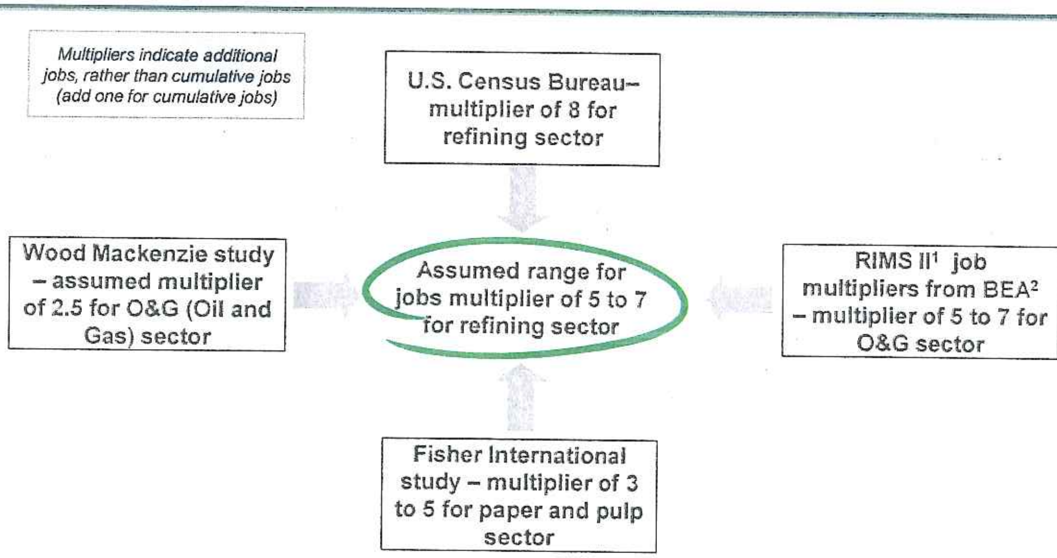
Refineries can be expected to invest in projects that lower emissions, such as heat recovery, better maintenance, and other energy efficiency projects

Based on congressional testimony, we estimate one job gained for every $200,000-300,000 of increased capital expenditure

Applying this conversion factor to the energy efficiency investments in the adjoining chart, we estimate 250-400 jobs could be created by 2017 and 400-600 jobs could be created by 2020

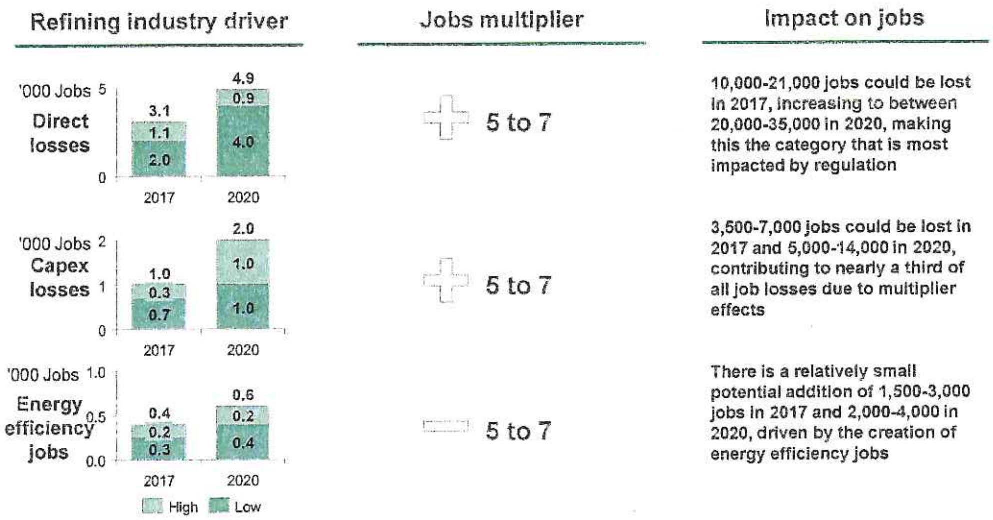
Source: Oil & Gas Journal; BCG experience; BCG analysis; congressional testimony by Dr. Margo Thorning on 2/9/2011

Exhibit 52



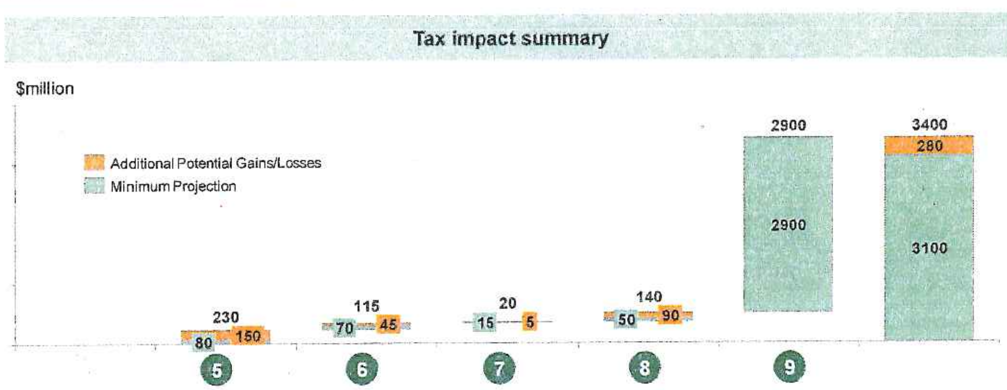
1. Regional Input-ouput Modeling System
2. Bureau of Economic Analysis
Source: BEA, Fisher International, Wood Mackenzie, U.S. Census Bureau

Exhibit 53



Source: Oil & Gas Journal, BCG experience, BCG analysis, congressional testimony by Dr. Margo Thorning on 2/9/2011, Fisher International, BEA, Wood Mackenzie, U.S. Census Bureau

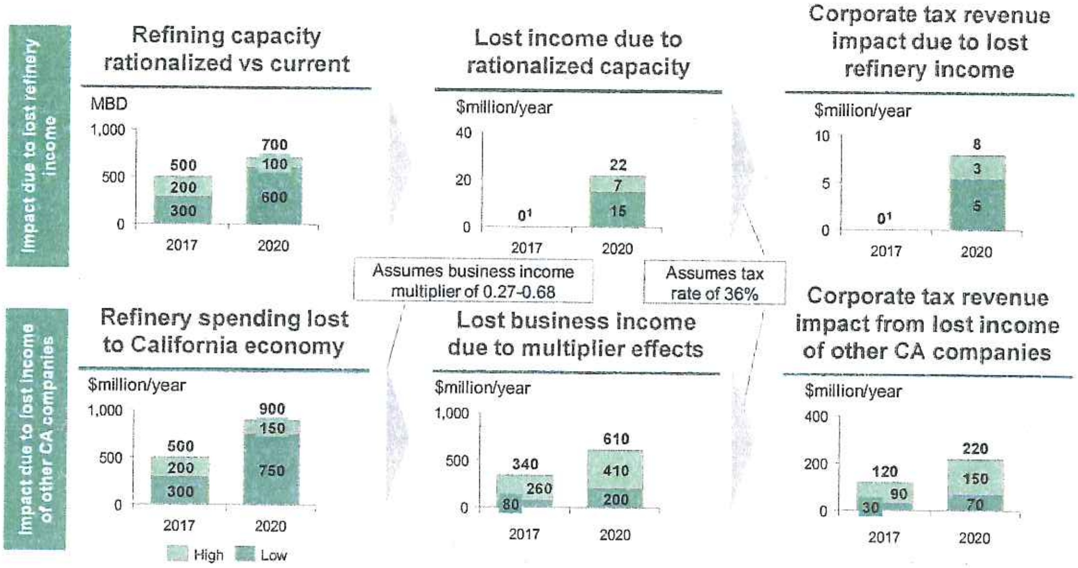
Exhibit 54



Key drivers	5	6	7	8	9
	Loss of income from refining companies and business affected by multipliers reduces taxable business income	Loss of income from refining employees and employees affected by multipliers results in lower taxable individual income	Differences in property values for refineries converted into terminals and refineries with lower expected cash flows reduces assessed property values	Reduced economic activity results in lower sales tax collection	Changes in patterns of fuels consumption results in lower excise taxes on fuels

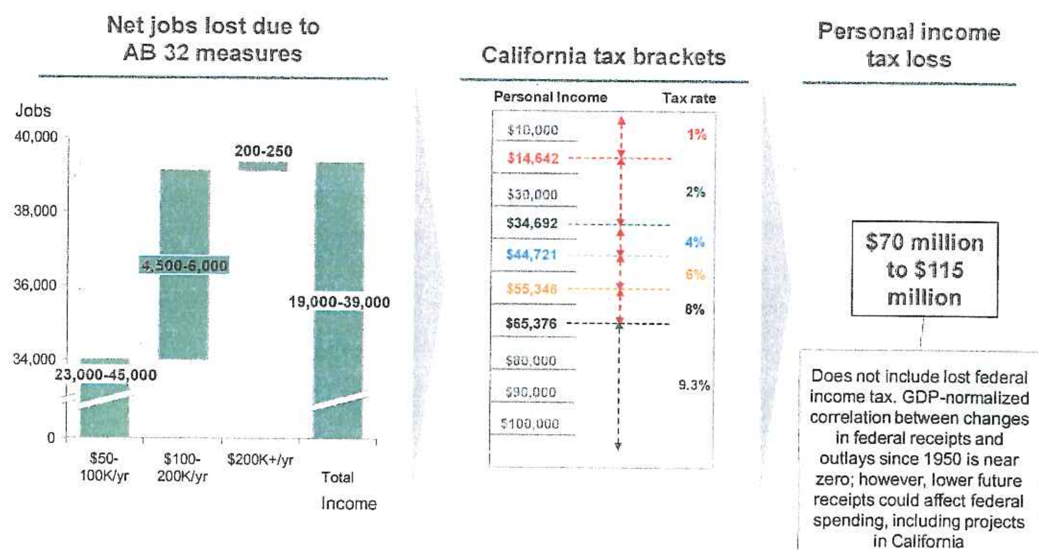
Source: Source: Oil & Gas Journal, BCG experience, BCG analysis, congressional testimony by Dr. Margo Thorning on 2/9/2011, Fisher International, California Franchise Tax Board, Solomon, BEA, Wood Mackenzie, U.S. Census Bureau, CBO report, IRS data, World Bank

Exhibit 55



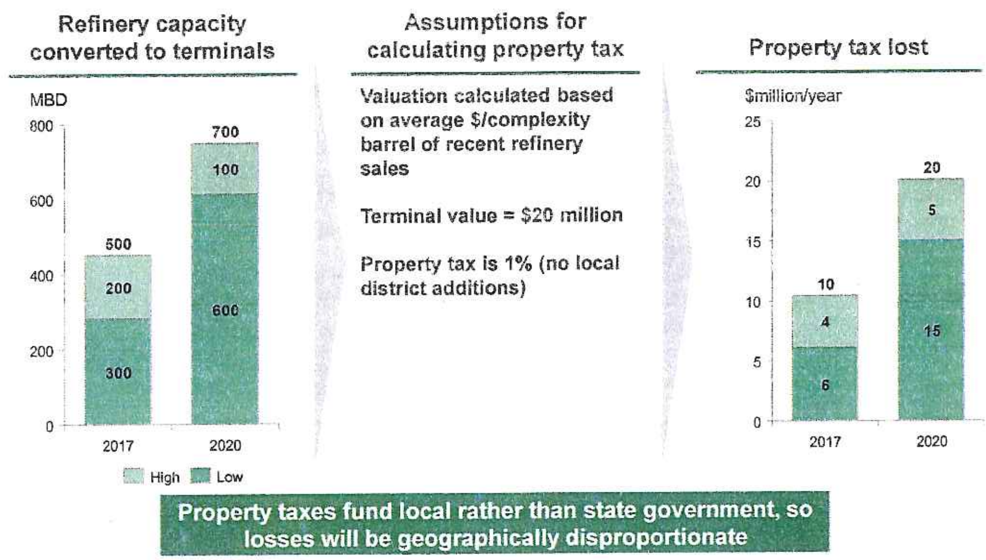
1. Refineries expected to close by 2017 do not have taxable income
Source: Oil & Gas Journal, BCG experience, BCG analysis, California Franchise Tax Board, CBO report, IRS, World Bank

Exhibit 56



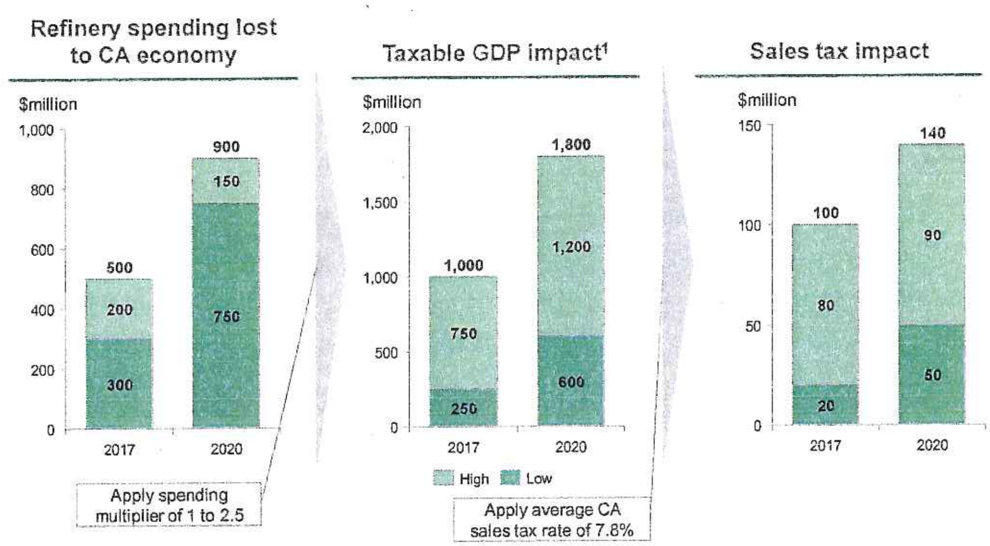
Note: Job numbers and distribution calculated based on average of second and third quartile Solomon values
Source: Oil & Gas Journal, BCG experience, BCG analysis, congressional testimony by Dr. Margo Thorning on 2/9/2011, Fisher International, California Franchise Tax Board, Solomon, BEA, Wood Mackenzie, U.S. Census Bureau

Exhibit 57



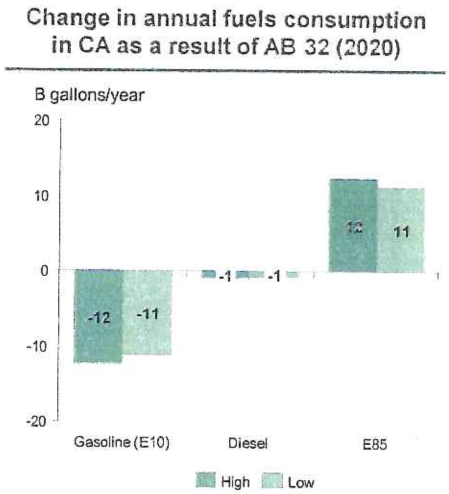
Source: Nelson, O&G Journal, California Board of Equalization, BCG analysis

Exhibit 58



1. Assumes 20% of GDP is not taxable
Source: Oil & Gas Journal; BCG experience; BCG analysis; California Franchise Tax Board; CBO report

Exhibit 59



Source: California Energy Commission; California Board of Equalization; BCG analysis

Excise tax impact

Gasoline (E10) is taxed at $0.357/gallon while E85 and diesel are taxed at $0.13/gallon

Based on this, California can expect to lose $4B-$4.4B from gasoline excise tax and $110M-$120M from diesel excise tax

California can expect to gain $1.5B-$1.6B from excise tax on E85

Exhibit 60

Estimates indicate that there will be a wealth transfer from the private sector to CARB of $3.7B per year by 2020 due to AB 32; this could potentially be significantly higher depending on the cost of carbon in the general auction

California could face several other impacts

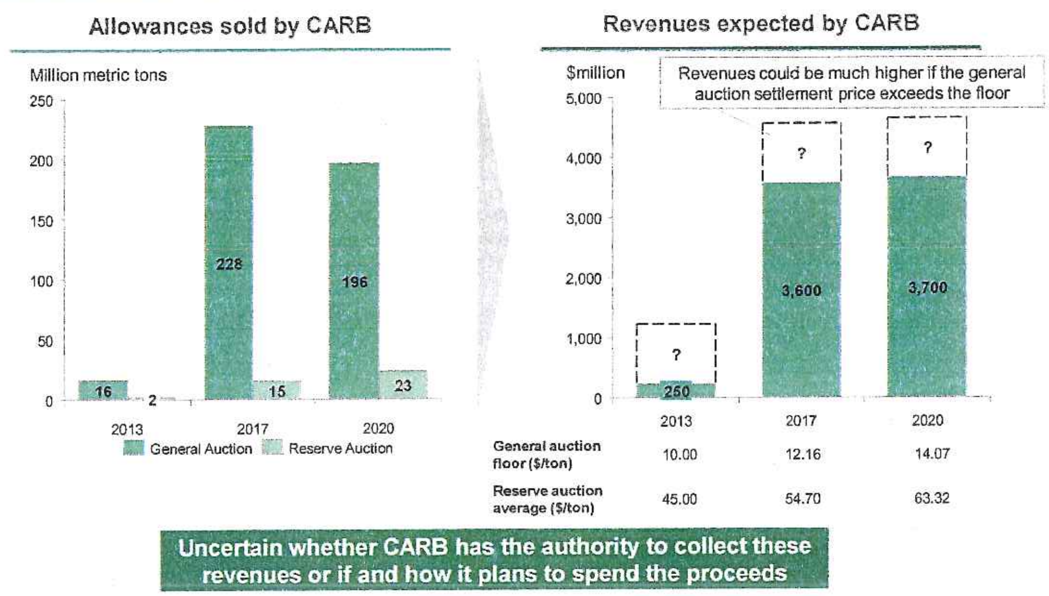
- CA could lose significant expertise in the areas of engineering, skilled mechanical trade, and professional services
- Increased fuels costs are likely to propagate throughout the economy, increasing the cost of living in California

The Cap and Trade program can be expected to achieve the goal of AB 32 by reducing emissions by 80 million metric tons versus Business As Usual, although some of that will come at the expense of increased emissions in other parts of the world

- Up to 12 million metric tons per year of emissions in California will be the result of producing fuels that are exported due to LCFS
- A substantial amount of CO_2 reductions will occur from shifting end-use of fuels produced in CA to locations outside of CA without any reduction in global emissions
- Crude shuffling with increase global emissions by increasing transport of crude oil

Positive impact of AB 32 · Negative impact of AB 32 · Negative impact to private sector; positive impact to CARB

Exhibit 61



Source: CARB; BCG analysis

Exhibit 62

Loss of economic activity in the refining sector (as well as other industrial sectors) will result in fewer job opportunities or projects of interest for several job classes:

- Engineers
- Specialized mechanics and tradesmen
- Supporting professional services (e.g., project management)

As a result, more people with experience in these areas will leave the state, and fewer Californians will seek training in such areas in the first place

The loss of supply of qualified people in these fields will have an effect on California's business environment that is difficult to quantify but unambiguously negative

Exhibit 63

Transportation dependent industries are likely to see the highest increases in costs, which will need to be recovered upon sale of products

- Trucking
- Railroads
- Airlines
- Taxis, buses, etc.
- Logistics (i.e., UPS or FedEx)
- Marine transportation
- Independent workers (i.e., plumbers, furniture movers, maids, etc.)

Other industries that are heavily dependent on fuels will be affected similarly

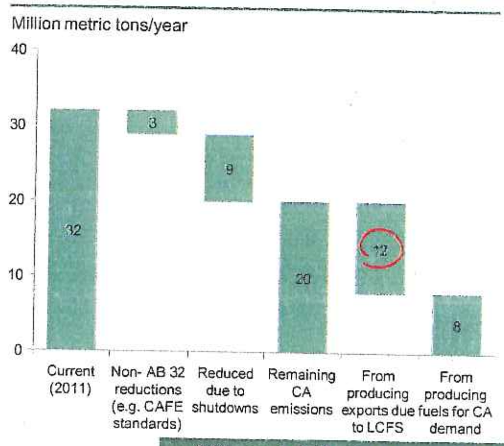
- Essential services that require diesel generators (e.g., hospitals, schools etc.)
- Manufacturing facilities with diesel turbines
- Farming (farm equipment uses diesel)

Public transportation will also face budgetary pressures due to higher fuels costs

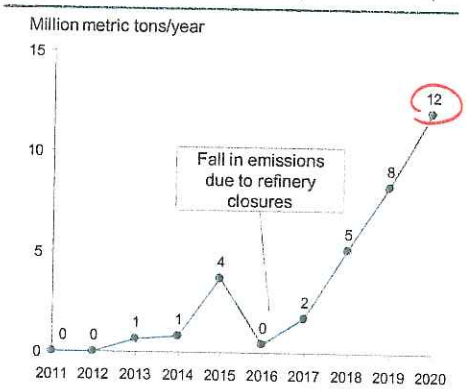
Ultimately, almost every business relies on transport to some extent, so there will be a general increase in the cost of living in CA

Exhibit 64

Breakdown of projected California stationary emissions in 2020



Emissions in California from gasoline exports due to LCFS (out of total 32 million MT of 2011 refinery emissions)



Although tail pipe emissions are reduced, gasoline is still produced and exported; stationary emissions remain in CA

Source: CARB, CEC demand forecast, BCG analysis