Emission Reduction Policies and Implicit Carbon Prices in the United States

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Introduction

This report contains the work performed for the Australian Productivity Commission's study on emission reduction policies and implicit carbon prices in key economies. The report describes key electricity and transportation policies at the federal, state, and local levels in the U.S. For many of the policies, estimates of abatement and implicit carbon prices are also provided.

The next section presents a background to the electricity sector and transportation sector in the U.S. and describes the methodology used to estimate abatement and implicit carbon prices. Section 2 covers electricity policies and section 3 covers transportation policies. Section 4 concludes with two table that summarize the key data for the policies.

1 Background and methodology

1.1 Electricity

The electric power sector in the United States is quite complex in terms of regulatory institutions, markets and technologies. This discussion highlights the aspects of the sector that pertain most directly to the policies discussed in the next section. In particular, I focus on generation markets in which owners of electricity generators supply electricity to retailers and large industrial consumers. There is a brief discussion of transmission at the end of the section, and I do not discuss retail markets or the distribution system in any detail.

1.1.1 Existing and forecasted generation stock

Table 1 shows the share of generation and carbon dioxide (CO_2) emissions by major technology for 2009. For reference, total generation is about 4 billion megawatt hours (MWh). The table shows that coal accounts for about half of total generation and almost four-fifths of emissions. Wind accounted for about 2 percent of generation and biomass about 1 percent. The "other" category includes wind, biomass, oil, and a number of minor technologies.

Many of the generators are quite old, particularly the coal generators. Figure 1 shows the generation capacity of coal generators in operation in 2009 for 5-year age bins. About 70 percent of the coal generation capacity is between 20 and 45 years old. Absent unexpected policy or energy market changes, most of these units are predicted to continue operating for a long time. The Energy Information Administration (EIA) forecasts that only about 5 GW of coal generation capacity will be retired by 2035 (EIA 2010). Over the same time period, about 200 GW of new investment is expected to be needed to meet new demand, of which about 30 percent would be wind, 13 percent coal, and most of the remainder natural gas. Because coal has much higher emissions than the other technologies, the CO_2 emission intensity (emissions per MWh of generation) is expected to decrease slightly.

1.1.2 Structure of markets for electricity generation

It is useful to distinguish wholesale electricity markets, in which generators supply electricity to retailers and industrial customers, from retail markets, in which retailers sell electricity they have purchased on the wholesale market to households and businesses. This section focuses on wholesale markets. Wholesale market structure varies widely across the country. Some regions, such as the Northeast, Mid-Atlantic, Texas, and California, have active wholesale markets. In these markets, typically some amount of electricity is provided as part of long term contracts, and a short-term (e.g., day-ahead) market matches the remaining demand and supply at hourly or sub-hourly intervals. There may also be balancing markets that operate at shorter time scales to account for unexpected fluctuations in demand or supply.

Often these markets are structured so that owners of generators bid to supply electricity at a particular price. Offers are stacked in order of increasing bids, and the equilibrium price is equal to the highest bid such that total supply equals expected demand. In a competitive market, firms submit bids equal to their marginal cost, and the equilibrium price equals the marginal cost of the highest-cost generation unit needed to meet demand.

From a CO_2 emissions perspective, it is important that the highest-cost generation unit changes over time. Throughout the analysis, costs refer to marginal costs. As indicated by the Commission, the analysis focuses on the short run, in which capital costs are sunk. When demand is low, only a small set of the available units in the system operate—i.e., the lowest-cost generators. During such times, the marginal cost of the highest-cost unit in operation is low, and the electricity price is correspondingly low. As demand increases, increasingly high-cost units turn on, and the price increases. In other words, the supply curve can be constructed by ranking units in order of increasing marginal costs. As the demand curve shifts out, higher-cost generators must be used, and the electricity price increases. This discussion disregards operational constraints that many units have, such as limits to the amount that generation can vary from one time period to the next. Nevertheless, it is a useful approximation for the policy analysis below.

The preceding discussion has assumed that there is sufficient capacity to meet demand. When demand is very high, or many units are unavailable, all generators in the system may be operating. In that case, the price could exceed the marginal cost of the highest-cost unit.

This raises the possibility that firms may withhold supply to manipulate the price. There has been a long debate over the extent to which wholesale markets are perfectly competitive, particularly following the extremely high electricity prices and rolling blackouts in California in 2000 and 2001. Many analysts believe that whatever the situation during that period, wholesale markets are fairly competitive and are certainly more competitive now than they were ten years ago. For the purposes of this report, I assume that wholesale markets are perfectly competitive, so that firms do not strategically withhold supply and submit bids equal to their marginal cost.

In an effort to protect consumers from imperfect competition and more generally from having to pay high electricity prices, many markets impose price caps. Although price caps do prevent very high prices from occurring, such caps lead to insufficient investment in new generation capacity. Installing a new generator of any size or fuel type requires an up-front capital investment. This investment can be recovered over the lifetime of the generator during times when the price of electricity exceeds the marginal cost of that generation unit. Therefore, setting a price cap tends to depress investment because it lowers prices and reduces the ability to recover the initial investment cost. To address this problem, many regions of the U.S. have introduced capacity markets, in which units receive payments from the retailer for having generation capacity available. The goal of these markets is to provide enough incentive for investment in new generation capacity—if there is insufficient capacity available, prices will be high in the capacity market, which spurs entry.

By comparison, many regions of the country operate under traditional cost-of-service regulation. The canonical model is that a vertically integrated utility makes generation and transmission investment decisions subject to the approval of the state regulator, whose objective is to minimize the cost of meeting electricity demand. Generators are dispatched to meet demand in order of increasing cost, similarly to a wholesale market.

The distinction between cost-of-service and wholesale market competition is not as sharp as this discussion would suggest, however. For example, regulated utilities may be able to sell excess electricity into wholesale markets. Below, the policy analysis will reflect the actual market and regulatory conditions as closely as possible.

1.1.3 Marginal emission rate

Many of the policies discussed below create incentives for firms to invest in generation capacity of low-emission technologies such as wind, solar and biomass. This investment displaces generation from existing units in the short run, and displaces investment and generation in the long run. Abatement, defined as the decrease in CO_2 emissions caused by the policy, depends on emissions from the generation that is displaced in the short run and long run. This paper focuses on the short run, in which the rest of the generation system is fixed. As discussed next, the marginal emission rate is a useful concept.

Consider, first, an incremental change in a policy that causes a small amount of investment in a low-emission technology. The displaced emissions at any point in time are equal to the emission rate of the generation unit that is displaced—or, as discussed above, the emission rate of the highest-cost unit that would have been operating at that time. I refer to this emission rate as the marginal emission rate. When demand is low, the marginal emission rate is equal to that of a relatively low-cost generation unit, but when demand is high, the marginal emission rate is equal to that of a high-cost generation unit. For example, if a power system relies mostly on natural gas, the marginal emission rate increases with demand as higher-cost, and higher-emitting, natural gas units are used at the margin.

For an incremental policy change, the displaced emissions depend on the marginal emission rate. This emission rate varies substantially across power systems. Table 2 reports the share of generation by fuel type for some of the largest power systems in the U.S. for 2008. The bottom row reports the U.S.

average, which is similar to the 2009 estimates from Table 1. The other rows report generation shares for different power systems, and they show a tremendous amount of variation. For example, the Midwest relies mostly on coal, whereas New England uses very little coal. These differences suggest that the emission rate of the marginal unit varies across regions. Note that they are merely suggestive—for the policy analysis what matters are the marginal emission rates and not the average emission rates—but the table does demonstrate the need to be careful about estimating abatement for different regions.

In summary, abatement for an incremental policy can be estimated as long as the emission rate of the marginal unit is known at every point in time. For some regions, such as California, this is relatively straightforward, as natural gas is the marginal technology most of the time. For other regions like Texas, natural gas is sometimes marginal but coal may be marginal at night when demand is low (Castillo and Linn, 2011). These differences will be recognized in the abatement and carbon price estimates in the following section.

Estimating abatement for policies that cause more than an incremental amount of investment is far more challenging because the marginal generation unit is affected by the policy. In these cases, a model of the power system is usually needed to account for this effect.

1.1.4 Transmission

Transmission plays an important role in the way these policies function. Because transmission investment is not centrally planned in the U.S. and there are many regulatory and economic obstacles to constructing a new transmission line, it is often extremely challenging to coordinate transmission investment with electricity policies. For example, federal and state policies have caused a dramatic amount of wind investment in Texas. Most of the installed wind systems are in west Texas, but most of electricity demand is further east, and there has not been enough transmission capacity to allow the wind generated in west Texas to meet demand in the east. As a result, much of the wind generation had to be curtailed, and abatement was much less than it would have been in the absence of transmission constraints.

When possible, transmission constraints are accounted for when estimating abatement. The estimates should therefore be interpreted as the effect of the policies conditional on transmission policies and investments.

1.2 Transportation

Most of the transportation policies affect either the new vehicles market or the markets for transportation fuels. This section provides a brief overview of both markets.

1.2.1 The market for new passenger vehicles

Total sales in the new vehicle market were around 15 million in the mid 2000s, but sales have been 10-12 million in the past several years. The market is fairly concentrated, and the top 8 firms accounted for 88 percent of the market in 2008. GM, Toyota and Ford were the top three manufacturers that year. About half of the vehicles sold are passenger cars. The remainder is light trucks, which include sport utility vehicles, crossover vehicles, minivans and pickup trucks.

The corporate average fuel economy (CAFE) program is the major policy aimed at improving the fuel economy for new vehicles. The program applies separate standards for cars and light trucks that each automaker must meet. Figure 2 shows the standard for cars as well as the average fuel economy of cars in the U.S. market from 1975-2007. Average fuel economy has exceeded the standard nearly every year, but this figure masks the effects of the standard. The three U.S.-based automakers, Chrysler, Ford and GM, have generally met the standard. In contrast, Honda, Toyota and some other Asian automakers have exceeded the standard by a wide margin, whereas some European firms have failed to meet the standard and instead paid a fine for non-compliance. Research has concluded that standards have been binding for U.S. automakers but not for automakers that regularly exceed the standard (Jacobsen, 2010).

This heterogeneity has important implications for understanding the effect on the new vehicle market of an increase in the standard. A modest increase in the standard, say 1 mpg, could lead to an increase in average fuel economy that is less than 1 mpg. Constrained firms increase fuel economy, but some firms that exceed the standard may actually reduce their vehicles' fuel economy (Klier and Linn, 2010). This consideration may be less important for a very large increase in the standard, in which case the standard would be binding for all firms in the market, but it should be considered when estimating abatement as the standard is phased in.

1.2.2 Fuel markets

A large share of the transportation policies attempt to reduce CO_2 emissions by promoting renewable fuels such as ethanol and biodiesel. Consequently, the discussion of fuels markets focuses on the supply and demand for these fuels. The EPA rulemaking for the renewable fuel standard (EPA, 2010) provides an extensive background to these industries, and is the primary source for the following discussion.

Ethanol consumption in 2010 was about 12.5 billion gallons, and biodiesel was roughly 500 million gallons. Most of the ethanol and biodiesel were produce domestically; a small, although growing amount of ethanol has been imported from Brazil where it is refined from sugar. Most of the ethanol was produced from corn starch and most of the biodiesel from soy. Although the corn starch technology is fairly mature, there is a vast amount of research at universities, government laboratories and private firms into alternative feed stocks and processing technologies. Some demonstration-stage plants produce cellulosic ethanol and biodiesel, but nothing yet is at commercial scale. Although cellulosic and certain biodiesel fuels are closest to marketability of the alternative technologies, there is a vast array of other possibilities currently under investigation.

Corn grown for ethanol is concentrated in Iowa, Illinois, Nebraska, Minnesota and South Dakota, which collectively account for two-thirds of total production. In 2008, 30 percent of the corn grown in the U.S. was used to produce ethanol. This large share, and the prospect of greater ethanol production in the future, has raised concerns about the effect of ethanol production on corn prices. Roberts and Schlenker (2010) suggest that this effect could be quite large, but this discussion is beyond the scope of this report.

After the corn is collected it must be refined into ethanol. The top 9 firms account for about 45 percent of capacity. Based on this fairly low concentration, it seems reasonable to assume that this market is competitive.

Demand for ethanol comes from several sources. First, ethanol is a gasoline substitute. If the price of gasoline is sufficiently high compared to the price of ethanol, fuel blenders will choose ethanol instead of gasoline. Second, in some regions ethanol is used to meet fuel standards or environmental regulation. This is an important consideration when analyzing the effect of a national quantity-based standard on ethanol production; in the absence of the standard ethanol production would still be substantial even if ethanol prices are high.

Finally, ethanol may be consumed as E85, which is 85 percent ethanol and 15 percent gasoline. As opposed to lower ratios of ethanol such as E3 or E10 (3 or 10 percent ethanol), which are certified for use by all passenger vehicles, E85 can only be used by vehicles that have certain equipment. Many manufacturers sell vehicles that have this capability, and existing vehicles can be retrofit at a cost of several hundred dollars. Nonetheless, because of the specialized vehicle equipment, there is a fixed cost of using E85. There is also a fixed cost to providing E85 at retail gasoline facilities. Also, special dispensers and storage equipment are needed for E85; the EPA estimates that the cost of installing a dispenser at a gasoline station is $140,000-170,000. Currently, there are about 160,000 retail gasoline facilities in the U.S., about 1,200 of which can dispense E85.

The specialized vehicle, dispensing and storage equipment introduce a challenge to reaching higher levels of E85 consumption. If few retail facilities have E85, few consumers will purchase flex-fuel vehicles or retrofit their existing vehicles, in which case there is little incentive for retail facilities to offer E85. Corts (2010) shows that government fleet adoption can solve this chicken-or-egg problem by requiring government vehicles to use E85. This prompts retail gasoline facilities to offer E85, which increases the number of consumers who drive a vehicle capable of using E85.

Conditional on owning a vehicle capable of using E85 and on fuel availability, whether consumers purchase E85 depends on the relative price of gasoline and ethanol, of course. Fuel economy is about 30 percent lower with E85 than with gasoline, so E85 should sell at a discount. In general, E85 is not sufficiently discounted to account for the sacrificed fuel economy (Anderson, 2010). Consequently, consumers who purchase E85 are not aware of the fuel economy issue, or they have strong environmental or other reasons for purchasing E85.

Beyond these issues, there are infrastructure and regulatory challenges to increasing the use of biofuels. First, before it can be sold for retail, ethanol must be blended with gasoline and biodiesel with diesel fuel. Because existing refineries are located in middle of country, and fuel blenders tend to locate on the coasts, the biofuels must be transported considerable distances. Currently, this is done mostly by rail, barge and truck. Ethanol is more costly to transport than biodiesel because it is difficult to use pipelines. Furthermore, special storage and dispensing equipment is needed for ethanol.

A second challenge to reaching higher levels of ethanol consumption is the “blend wall”. Currently, ethanol distribution and blending infrastructure, industry standards, and regulations allow for ethanol blends up to 10 percent ethanol (E10); it is not practical to produce blends higher than E10 other than E85. Therefore, with national demand for gasoline around 140-150 billion gallons per year, if all of the gasoline were E10, this would translate to 14-15 billion gallons of ethanol per year. To produce and consume more than this would require greater use of E85—which is challenging for reasons discussed above—or changes in the regulation and industry standards.

The final point about biofuels regards the emissions achieved by switching to biofuels. There has been a lot of debate over lifecycle emissions of these technologies, which is not repeated here. The EPA now requires that fuels meet a particular lifecycle emissions reduction to qualify as a renewable fuel. Lacking sufficient data on actual emissions reduction achieved by existing biofuels production, I assume that the renewable fuels achieve the EPA emissions requirements.

To summarize this discussion, and to provide some of the data needed for subsequent calculations, Tables 3-5 report statistics by fuel and state. Table 3 shows consumption in trillion BTUs by state and for the entire United States. Table 4 shows fuel prices in dollars per million BTU. The statistics for both tables were obtained from the 2008 EIA State Energy Data System.

Table 5 reports imports, exports, and emissions for the major fuels. There are two things to note about the emissions estimates. First, the gasoline and diesel estimates include lifecycle emissions, and were estimated by the EPA for the RFS2 program. Lifecycle emissions for the other petroleum products could not be obtained. This does not affect the analysis below because the objective of the policies considered is to replace gasoline and diesel fuel with ethanol and biodiesel.

Second, the emissions for ethanol are not specified, as there has been considerable controversy over the life cycle emissions from ethanol. RFS2 requires new biofuels to achieve particular reductions compared to gasoline or diesel fuel. In the abatement and carbon price analysis below, I assume that these reductions are achieved.

1.3 Framework for analyzing policies

I have followed the methodology put forward by the Productivity Commission. Abatement is defined as the difference between actual CO_2 emissions and counterfactual emissions in the absence of the policy; that is, abatement is the total abatement under the program, and not abatement due to an incremental policy change—the marginal emission rate approximation is not used when other estimates are available. For each policy, I describe the counterfactual scenario used to estimate abatement. For subsidies and taxes, when available I provide estimates of the total annual government revenue or expenditure.

I also provide estimates of the implicit carbon price for many of the policies. Using the Productivity Commission's definition of this term, it is straightforward to estimate the carbon price for a fuel tax or cap-and-trade program. Other policies, particularly technology or quantity standards such as the renewable fuel standard, are far more challenging. The implicit carbon price depends on the economic incentive created as well as the abatement. For example, under a renewable portfolio standard (RPS), a qualifying renewable generator receives a per-MWh subsidy equal to the price of the associated renewable energy credit. The subsidy in this case is in units of dollars per MWh, so to estimate a carbon price the abatement must be estimated. When possible, marginal abatement is estimated, but in many cases the carbon price is more properly thought of as an average price because insufficient data are available. For the electricity sector, regional differences in the generation stock present additional challenges, as discussed above.

In general, there are two major challenges to providing these estimates. First, policies may overlap, and second, policies have dynamic effects that are difficult to model. These challenges introduce a number of caveats to the estimates, which I discuss in this section before turning to the estimates themselves in the following two sections.

When two policies overlap, meaning that they both create incentives for the same investment or behavioral change, only one policy can be binding. Available data are used to assess which policy is binding, although definitive conclusions cannot always be reached. When one of the policies is a quantity-based standard, such as an RPS, renewable fuel standard (RFS) or fuel economy regulation, there are two subcases to consider, depending on whether or not the quantity-based standard is binding. When the standard is not binding, the implicit carbon price and abatement of that policy equal zero. When the quantity-based standard is binding, the total implicit carbon price is equal to the sum of the carbon price from the standard and the carbon price from the other policy (e.g., a fuel tax credit).

The same is true for abatement when a quantity-based standard overlaps with another policy. When the standard is not binding, abatement under the standard is equal to zero. Abatement under the other policy can be estimated by comparing actual emissions with emissions in the absence of that policy. When the standard is binding, total abatement equals the sum of abatement from the standard and abatement from the other policy. That is, the abatement of the quantity-based policy is equal to the difference between actual emissions and counterfactual emissions that would have occurred in the absence of the quantity-based policy. Abatement from the other policy equals the difference between counterfactual emissions from the previous step, and counterfactual emissions when both policies are removed. Unfortunately, I am not aware of any studies that perform the exercise of sequentially removing policies in this manner, or which remove all policies that overlap. Therefore, I can usually estimate abatement under the quantity-based standard relative to the counterfactual in which the other policy is in place, but I cannot estimate abatement under the other policy.

Several dynamic issues pertain to many of these policies, which make it difficult to estimate abatement and carbon prices and determine which policies are binding. The first is that many of the policies effectively create incentives for new investment. This can cause over-compliance with a policy when it is first being phased in. For example, firms may construct new ethanol plants in anticipation of an increase in the ethanol requirement under the RFS. This would cause actual ethanol production to exceed temporarily the production mandated by the program and could cause credit prices to be close to zero (particularly if there are banking limits). Dynamic effects of a policy on investment also makes it difficult to assess counterfactual emissions when a subsidy has expired and been reintroduced subsequently, such as with the tax credit for wind generation.

Second, the counterfactual should be defined to be the market equilibrium that would occur in the absence of the policy. This requires a different type of analysis for policies that were recently implemented, as compared to policies that have been in place for a long time. For the latter, a true long run estimate would be desired, which accounts for all of the capital investments that have taken place because of the policy. For example, states have levied fuel taxes for a long time, which may have affected individuals' decisions about where to live and work, and which definitely have affected the quantity and quality of roads and highways. All of these decisions affect gasoline consumption, and they should be included in the policy analysis. For certain policies I am able to provide estimates that include at least some of these effects, but not always.

The third dynamic issue is that the objective of many of these policies is to spur innovation. The RFS, for example, provides economic incentives for cellulosic ethanol, which could in turn promote innovation. Because this report focuses on recent abatement and carbon prices, it may therefore mis-characterize the long run incentives created by a policy. In other words, some policies could provide stronger (or weaker) incentives for innovation than an actual carbon price. For that reason, even if an implicit carbon price could be estimated without all the difficulties just mentioned, it would not permit a true apples-to-apples comparison with an actual carbon price.

A final complication is that quantity-based standards, such as an RFS or RPS, implicitly tax certain technologies and subsidize others. In an RPS, for example, renewable technologies are subsidized because they receive additional revenue in the form of the renewable energy credit (REC) for each unit of electricity they generate. Other technologies are implicitly taxed, because the retailer must purchase some renewable electricity for every unit of non-renewable electricity it purchases in order to comply with the RPS; this effectively increases the cost of purchasing non-renewable electricity and acts like a tax. The joint tax and subsidy can have ambiguous effect on output prices and therefore abatement (Holland et al., 2009, and Fischer, 2010), which should be considered in principle, but it is very difficult to do so in practice. As instructed by the Commission, I do not consider these issues, which amounts to assuming that the relevant electricity or fuel demand curves are vertical.

2 Electricity Policies

2.1 Regional Greenhouse Gas Initiative

2.1.1 Background

The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade system for electricity generators 25 MW or greater in the Northeast and mid-Atlantic regions. Each state receives a share of the total emissions permits that it distributes to the regulated firms either for free or via an auction. The total cap decreases gradually over time, so that in 2018 the cap will be 10 percent less than the initial cap in 2009. The 2009 cap was set at a level somewhat greater than historical emissions.

The states have some discretion about how they allocate the permits. Most of the permits have been sold in quarterly regional auctions, and the share of permits that are auctioned varies across states. The auctions have a minimum bid, which for the most recent auction was $1.89 per short ton of CO_2 ($2.05 per metric ton of CO_2, $mtCO_2$). Much of the auction revenue is reinvested in energy efficiency projects and renewable technologies; roughly $500 million have been invested this way according to a recent RGGI report.

2.1.2 Abatement

The RGGI permit price has been close to the minimum bid since mid 2010; the most recent price is \$2.05/mtCO_2. This implies that abatement because of the cap is very close to zero. There may be a few abatement options that cost less this amount, so that abatement has not been precisely zero. At most, i.e., if coal is always marginal and electricity demand were perfectly inelastic, the wholesale price of electricity would increase by about $0.002/kWh. Therefore, most likely there has not been any abatement due to a reduction in electricity demand.

The very low permit price is not surprising given the recent recession and the fact that the cap was set above historical emissions. As the cap tightens or as economic conditions improve, the cap may become binding and abatement may increase. Note that there may have been, and probably was, some abatement from the re-investment of the auction revenue. Insufficient data are available to estimate the extent of this abatement.

As with the Western Climate Initiative, there has been a lot of concern about leakage, in which emissions reductions within the RGGI program are offset by emissions increases from generators outside of the program. The source of this concern is that because the RGGI program increases the operating costs of generators inside the program but not the costs of generators outside of the program, generation from the latter would increase at the expense of the former.

Before the program began, studies predicted varying amounts of leakage. Burtraw et al. (2005) predict leakage rates of 17-40 percent of the emissions reduction under the cap, while Chen and Sauma (2008) predict leakage of 80-90 percent in the short run. In practice, this issue is moot because the emissions price has been so low in RGGI. The program has had a minimal effect on the costs of generators in the program, and therefore has probably had a very small effect on emissions from generators outside the program.

2.1.3 Carbon price

Since the middle of 2010, the auction price has been close to the reserve price, which was \$2.05/mtCO_2 in early 2011. More specifically, the auction price was \$2.28/mtCO2 in March 2010, \$2.07/mtCO2 in June 2010, and \$2.05/mtCO2 thereafter.

The fact that the permit price has been equal to the reserve price means that the program can effectively be interpreted as a carbon tax equal to the reserve price. As noted above with abatement, as the cap tightens or if demand for electricity increases in the future, the carbon price could increase.

2.2 Western Climate Initiative

2.2.1 Background

The Western Climate Initiative (WCI) includes a number of states and provinces in the U.S. and Canada. The WCI provides a framework for linking carbon markets in these regions. In the U.S., only California and New Mexico have passed legislation to implement a cap-and-trade program, and the status of New Mexico is uncertain with the election of a new governor in 2010. Therefore, this analysis focuses on California, specifically, on the AB 32 program.

Under AB 32, a cap-and-trade program will begin in 2012 that eventually covers about 85 percent of emissions from California. Initially, the program will include electricity generators, electricity imports, and large industrial facilities. In 2015, the program will expand to include transportation fuels, natural gas, and other fuels. The cap declines linearly for the initial sectors between 2012 and 2020 so that emissions in 2020 are equal to emissions in 1990. Similarly, for the sectors that enter in 2015 the cap declines linearly from 2015 to 2020 so that their emissions also equal 1990 levels. According to the

California Air Resource Board (CARB, 2010), the cap is set at 436.4 mtCO2 including all modeled sectors. Note that offsets are allowed up to 8 percent of total abatement, although CARB estimates that fewer offsets would be used.

2.2.2 Abatement

There has been a lot of debate about the amount of abatement that would occur under the program. The debate centers not on the estimated 25 percent decrease in emissions, but on the effects of AB 32 on emissions outside of California. Abatement should be measured as the total change in emissions relative to the counterfactual—that is, emissions both within and outside of California should be measured. The chief concern is that the cap will cause emissions to decrease inside of California, but the decrease may be at least partially offset by increases in emissions elsewhere; the increase is commonly called emissions leakage.

This concern is particularly important in the electricity sector, because electricity imports (i.e., electricity generated outside of California and transmitted into the state) meet 20 percent of load but account for about two-thirds of emissions. Bushnell (2007) has argued that if the importer of electricity is liable under the cap (as opposed to the owner of the generator), it may be possible to reshuffle electricity contracts with generators outside of California. After reshuffling, the emissions associated with the electricity imported into the state decrease, but total emissions remain unchanged. Palmer et al. (2009) argue that this may overstate the case, and that it might not be so easy to decrease emissions of imports without decreasing actual emissions.

Several studies have estimated the extent of the leakage in 2020. Palmer et al. (2009) estimate that leakage could amount to 30-50 percent of the reduction in emissions from the electricity sector in 2020. Electricity accounts for about 30 percent of emissions of the regulated industries, and assuming that there is no leakage in the other regulated sectors, this estimate implies that 9-15 percent of the emissions reduction under the cap may be offset by emissions increases outside of California.

The CARB has also published the results of its regulatory analysis. The analysis includes forecasts of abatement by sector and total abatement under the cap. CARB uses a growth model and a static computable general equilibrium (CGE) model. The growth model estimates abatement, the carbon price, energy consumption and other variables based on assumptions about energy prices, growth, and other factors. The model focuses on energy consumption and the associated CO_2 emissions, and attempts to capture capital investments and energy efficiency decisions based on market and regulatory signals The CGE model is used to evaluate the effect of AB32 on employment and income, and takes the investment and efficiency decisions as inputs.

It is important that the California Air Resource Board proposes a large number of other policies to complement the cap. Abatement is estimated with reference to the counterfactual in which none of the complementary policies is in place. The baseline (reference) case includes a 20 percent RPS requirement (which is the amount required in 2012), the Pavley/CAFE fuel economy standards, and the federal RFS. The case that includes the cap also includes a number of complementary policies, such as the LCFS and more stringent fuel economy standards (Pavley II). Reference case emissions in 2020 are 527.9 million $mtCO_2$, and emissions under the cap are 436.4 million $mtCO_2$ if offsets are not allowed, and 448.5 million $mtCO_2$ if offsets are allowed (the analysis includes an offset supply curve based on EPA analysis).

2.2.3 Carbon price

The implicit carbon price would likely be fairly low in the first few years of the program while the cap is relatively large. Estimates of the price when the program is fully implemented in 2020 vary. Palmer et al. (2009) estimate \$50-\$110/$mtCO_2$ using a model that only includes the electricity sector.

By comparison, CARB estimates an allowance price of \$25/ton CO_2. This number is so much lower because the complementary policies are included (e.g., an RPS). Effectively, the complementary policies reduce emissions in the absence of the cap, so a lower permit price is needed to reduce emissions to the level of the cap, as compared to the case in which the complementary policies are not included. CARB estimates allowance prices of \$162/ton when the complementary policies are partially removed. It is difficult to determine why the estimate is so much higher than Palmer et al. because there are significant differences between the two analyses.

2.3 Section 1603 renewable grants, business investment tax credit, and residential investment tax credit

Section 2.10 discusses this program in conjunction with the renewable energy tax credits.

2.4 California Solar Initiative

2.4.1 Background

The California Solar Initiative (CSI) includes several components: rebates for installing residential solar systems in the three major utility service territories in California; a solar hot water rebate program; a solar rebate program for low-income single family and multiple family homes; and grants for research, demonstration and deployment. I focus on the residential solar segment of the CSI.

The program offers a subsidy per unit of installed capacity or per unit of generation. The capacity-based subsidy is determined for each installation and is estimated from the characteristics of the installation (module type, tilt, etc.). The generation-based subsidy is paid over five years after measuring actual generation. The subsidy system is designed so that in expectation the capacity- or generation-based amounts are equal, after allowing for an 8 percent discount rate. Systems greater than 30 kW must use the generation-based scheme and smaller systems can choose either scheme. The total budget of the program is $1.76 billion, through 2016.

The level of the subsidy decreases over time with the total installed capacity in the corresponding utility service territory. There are 10 steps for the program, with a lower amount offered in each successive step. Most of the state is in step 8, which provides $0.35 per peak watt (Wp) for the capacity-based program and $0.05/kWh for the generation-based program. (A Wp is the standard unit of measurement for photovoltaic capacity. A system with 1 Wp of capacity produces 1 watt of power in ideal conditions.) These amounts should be compared to the average installed costs, which are typically about $7/Wp for smaller systems. Table 9 reports the annual installations and expenditure under this program from 2007-2010.

2.4.2 Abatement

I am not aware of any studies that estimate abatement under the CSI. This is largely because there are about 50,000 installations, and detailed measurements of electricity generation from even a large fraction of the systems is hard to obtain. Therefore, I estimate abatement under a number of assumptions as described next.

Abatement depends on the amount of generation displaced by solar and the emission rate of the displaced generation. According to the CSI website (which relies on administrative data collected by the state regulatory agency), 491 MWp of solar have been installed under the CSI. Note that this amount does not include installations whose applications to the CSI are currently being processed, it does not include large systems in California that do not qualify for the program, and it does not include PV installations that were constructed prior to the beginning of the CSI in 2007.

Based on simulations of a model from the National Renewable Energy Laboratory, the capacity factor of a typical PV system in California is about 21 percent. After converting from DC to AC generation by assuming that 10 percent of the energy is lost in the conversion, PV generation from CSI systems in 2010 was 813,000 MWh.

California relies heavily on natural gas generation (see Table 2). It is reasonable to assume that natural gas is always marginal. This assumption is consistent with the CPUC's analysis of the Self Generation Incentive Program and other programs (Itron, 2010), and is consistent with the findings of Connors et al. (2005), who estimate the generator displaced by a small increase in solar generation for each power system in the U.S.

Systems installed under CSI connect to the distribution grid. I assume that the generation displaces natural gas generation at central station power plants. Therefore transmission and distribution line losses must be accounted for. According to Borenstein (2008), total losses in California average around 7 percent. Finally, I assume that, after accounting for line losses, solar generation displaces natural gas one-for-one—i.e., adding solar to the system does not increase the need for spinning reserves or other ancillary services (this should be a reasonable approximation given the relatively small share of total generation accounted for by PV). Thus, the PV generation displaced about 869,000 MWh of natural gas generation.

Finally, I assume a natural gas emission rate of 0.6 $mtCO_2$/MWh of generation. This emission rate is higher than the average emission rate for natural gas in the U.S., which is about 0.5 $mtCO_2$/MWh. This assumption reflects the fact that at the margin the higher-cost and less efficient natural gas are displaced. For policies that displace a lot of natural gas generation, the average emission rate of the displaced gas units may be lower, and perhaps closer to the overall average. Nevertheless, throughout this report 0.6$mtCO_2$/MWh is the emission rate used to estimate abatement from displaced natural gas. Under these assumptions, abatement was equal to 522,000 $mtCO_2$.

2.4.3 Implicit carbon price

The implicit carbon prices are computed using the current value of the subsidies, rather than obtaining an average value of the subsidy over the history of the program. This is an important disctionction because the subsidy has been declining over time.

Similarly to the abatement estimates, I calculate carbon prices assuming that the solar displaces natural gas on a one-for-one basis (after accounting for line losses). The performance-based subsidy therefore amounts to an implicit carbon price of \$89/mtCO_2. Note that this effective price only applies for the first five years the system is in operation. Assuming that the system operates for 25 years and discounting at 8 percent, the economic incentive would be the same as introducing a carbon price of \$33/mtCO_2 for each year the system operates. For the capacity-based subsidy, the implicit carbon price is \$33/mtCO_2, which is the same as the performance-based subsidy.

2.5 New Solar Homes Partnership

2.5.1 Background

This and CSI are part of the "Go Solar" initiative in California. The program offers subsides to solar installations at new homes and developments. The subsidy amount is determined similarly to the CSI subsidy, and is based on the capacity and expected performance of the system. The subsidy declines over time with the cumulative amount installed under the program. The base subsidy was \$2.50-\$3.50/Wp in 2007 (the amount depended on the characteristics of the home or development). Similarly to the CSI, the amount of the subsidy steps down with the cumulative capacity installed under the program.

According to the program's website, 25.51 MWp have been installed as of November 2010. The total budget is \$70.97 million through 2016. Based on the amount of installed capacity under the program, the current subsidy level is around $1.75-$2.75/Wp, where the actual amount depends on the characteristics of the home or development.

2.5.2 Abatement

Abatement and the carbon price are estimated using the same assumptions as the CSI. Given the installed capacity through November, 2010, total abatement is 27,000 mtCO_2 per year.

2.5.3 Implicit carbon price

At the current subsidy rates, the carbon price is $166-259/mt$CO_2$.

2.6 Self Generation Incentive Program

This California program offers subsidies on an installed-capacity basis to wind, fuel cells, and storage systems that provide distributed generation or storage services. Currently, the program subsidizes wind, fuel cells and storage, although the program formerly subsidized PV as well. From 2001-2009, the program provided $622 million in subsidies for completed projects, with PV accounting for about 74 percent of the total subsidy (Itron, 2009). Historically, PV and internal combustion engines were the two most prominently supported technologies, with each accounting for about 40 percent of total installed capacity for completed projects. Wind, fuel cells, and storage account for a very small share of installed capacity and government expenditure, but only these technologies are included in the program since 2008 when the CSI began.

The current subsidy amounts are $1.50/W for wind, $4.50/W for fuel cells, and $2.00/W for storage. The minimum system size is 30kW and the maximum is 5 MW, but for systems above 1 MW the per-watt subsidy is lower and is equal to zero above 3 MW. There is also a 20 percent bonus for systems manufactured in California. The total 2010 budget was $74.7 million, of which half is allocated to wind or fuel cells and storage that uses renewable fuel. The other half is allocated to fuel cells and storage that use non-renewable fuel.

According to Itron (2010), SGIP facilities produced over 868,000 MWh in 2008. The report claims that these facilities provided net reductions of 63,000 $mtCO_2$. There is not a lot of detail about the methodology, but it appears that this represents the sum of estimated abatement at each facility. Abatement at each facility is measured by comparing actual emissions with emissions that would have occurred if the facility's electricity demand were the same but the SGIP facility did not exist. Counterfactual emissions include power plant emissions (which are estimated using an hour and service territory-specific emission factor), and from cooling, heating and biogas treatment services. The emission factor is calculated by assuming that wholesale electricity price variation over time reflects variation in the heat rate of the marginal natural gas generator. The electricity price variation is then used to estimate the heat rate of the marginal generator in each hour, from which emission factors are calculated. Note that this calculation does not seem to account for transmission congestion (which causes displaced emissions to vary across locations), but it is better than using a constant emission rate.

PV accounted for most of this abatement and the PV abatement actually offset an increase in emissions from the non-renewable fuel cells, turbines, and internal combustion engines that participated in the earlier phase of the program. Given that PV is no longer subsidized under this program and wind has not historically been a major part of the program, the SGIP is unlikely to result in significantly more abatement in the future.

2.7 Emerging Renewables Program

This California program provides subsidies for small wind and fuel cell facilities that do not receive subsidies from the SGIP. During 2010, the subsidy for fuel cells was $3/W up to 30kW and for wind it was $3/W for the first 10 kW and $1.50/W for each watt between 10 and 30 kW. Only wind facilities less than 50 kW qualify for the program.

2.8 State renewable portfolio standard (RPS) programs

2.8.1 Background

As of 2010, 32 states have renewable portfolio standards. Seven states have renewable goals that are not enforced by penalties. The RPS programs differ in many ways, but there are a few common elements. The electricity retailer is usually responsible for complying with the program, and must purchase a specified share of electricity from qualifying renewable electricity sources. Renewable sources typically include wind, solar, biomass and other technologies. Some programs also count new hydroelectric units as renewable.

Each MWh of electricity generated from these technologies yields a renewable energy certificate (REC). The retailer must purchase enough RECs to meet the standard. In some programs, RECs can be unbundled from the energy, which means that a REC obtained by a utility can be sold to another entity. With unbundled RECs, the retailer can comply by purchasing sufficient renewable electricity or by purchasing RECs from another retailer that purchases excess renewable electricity.

State RPS programs vary in many ways, and Table 6 provides summary information for each state in the U.S. The table indicates whether the state has an RPS that is enforced by non-compliance penalties or whether the state has a target, whether RECs are unbundled from the energy, whether REC trading is allowed, the percentage requirements for different classes of generators, generation by renewable technology in 2009, and recent REC trading prices. The REC prices were only available for a subset of states that have an RPS, and often the information is several years out of date. Note that many of the RPS programs have begun in the past several years. This probably explains the difficulty in finding data on REC prices. Furthermore, because the RPS programs usually increase in stringency over time, abatement has probably not been very high for these programs, but sufficient data are not available to test that hypothesis.

2.8.2 Abatement and implicit carbon price

Before discussing abatement and carbon prices for the individual state programs, I briefly discuss the recent literature on RPS programs in general. A number of studies assess the effect of a hypothetical RPS program, including Blair et al. (2006), Kydes (2007) and Palmer et al. (2010). The latter is a study by Resources for the Future that compares a hypothetical cap-and-trade program, a national RPS, and the tax credits. The study uses a detailed simulation model of the electric power sector, and simulates the effect of these policies out to 2035. The model includes 21 regional markets and accounts for regional differences in electricity market structure, installed generation capacity and environmental regulation. The cost and demand assumptions are the same as the assumptions used by EIA in the Annual Energy Outlook. Although not directly informative of the abatement under the existing state RPS programs, this report does suggest that a national RPS would be very costly per unit of abatement (the tax credits are even more costly). This is because of the inherent problems of an RPS that have been widely noted in the economics literature: an RPS only creates incentives for certain low-emission technologies and not others, which precludes many low-cost abatement opportunities such as switching from coal to natural gas.

Ideally, abatement would be estimated by comparing actual emissions for a particular year with counterfactual emissions, which are defined as the emissions that would have occurred in the absence of the program; all other variables and policies are held constant. Such information is not generally available, however. There are a number of qualitative studies of some of the major RPS programs, particularly Texas and California, but I have not found the sort of careful quantitative comparison of actual and counterfactual emissions that would be most desirable.

It is possible to get a rough sense of the implicit carbon price for states for which REC prices are available, however. For states that have a REC price close to zero, abatement and implicit carbon prices are probably close to zero.

Texas is a particularly interesting case to consider because about five percent of electricity in Texas is generated from wind. This does not appear to be due to the RPS, however. Actual wind capacity far exceeds the required amount of capacity in 2010 (the Texas RPS is implemented as a capacity requirement rather than a generation requirement). This suggests that the federal subsidies for wind and the excellent wind resources in west Texas are currently the largest determinants of wind investment in Texas. On the other hand, the REC price in Texas was around $10/MWh during the early and mid 2000s, which suggests that the RPS may have had a positive effect on wind investment in those years. It is unclear why the REC price subsequently fell to zero. Nevertheless, the fact that REC prices are currently zero means that the RPS does not currently cause any investment in wind.

For several other states, particularly New York, New Jersey, and some states in the northeast, REC prices have been positive in recent years. In those cases, the implicit carbon price is proportional to the REC price. The level of the carbon price depends on the emission rate of the marginal generator, which varies across the northeast and mid-Atlantic, but is often natural gas. The implicit carbon price is therefore roughly equal to the REC price divided by the emission rate of a natural gas generator, 0.6mtCO_2/MWh. Abatement for these programs is much more difficult to estimate, however, because it would be necessary to first account for the effect of federal, local, and other state subsidies for renewable technologies, but there is little research on which to draw.

2.9 Feed in tariffs

Feed-in tariffs are increasingly common, although several other terms, in addition to feed-in tariffs, are used to describe a program in which the utility pays generators a pre-specified electricity price. The term performance based incentive is increasingly common, and many programs are referred to as buy-back schemes. For this discussion, the term feed-in tariff refers to the set of programs in which a price for electricity generation is set by the utility for certain types of technologies. Despite their growing number, these programs are generally quite small and it is often difficult to disentangle them from the state RPS programs. A few of the more prominent examples are given here, and the primary data source is www.dsireusa.org.

Utilities in Wisconsin have several programs, including a performance based incentive of $0.066/kWh for wind generation and $0.30/kWh for solar. The wind program is capped at 0.25 percent of one of the utility's electricity sales, and the solar program is capped at 300kW.

California illustrates the difficulty of disentangling feed-in tariffs from the state RPS. As of September 2010, the California state regulator is in the process of redesigning the system, in which pre-specified rates are provided that vary over time (i.e., peak and off-peak). However, the program's objective is to support utilities attempting to comply with the state RPS, and the program may be capped at 750MW. This suggests that the program is primarily a financing tool, which provides investors a clear market price signal, and may not cause any additional abatement (although it could reduce costs).

Gainesville, Florida, offers a feed-in tariff for solar of $0.24-$0.32/kWh depending on the characteristics of the system. In 2010, the program was capped at 4MW of installed capacity. The cap was reached, and the cap for 2011 has been set at 2.7MW.

2.10 Renewable Electricity Production Tax Credit/Renewable Energy Production Tax Incentive/Business Energy Investment Tax Credit/Residential Energy Efficiency Property Credit

2.10.1 Background

These policies are discussed jointly because they are closely related. Historically, large wind projects have qualified for a tax credit of about $20/MWh of electricity generation, where the level of the subsidy has been indexed to inflation. This tax credit expired a few of times in the early 2000s but was reinstated a year afterwards in each case.

Large solar and other projects have qualified for a 30% investment tax credit (ITC), which was recently extended to include residential solar (previously, the residential tax credit was capped at $2,000 per system). But in 2009, the tax credit was changed to a treasury cash grant, and large wind projects could elect to receive the capacity-based grant instead of the performance-based tax credit. The tax credits are scheduled to expire in 2016.

Historically, investors in solar, geothermal, and biomass projects have claimed the investment tax credit. Wind investors have claimed the performance based credit instead. When the cash grant was introduced in early 2009, about two-thirds of wind projects elected to take the cash grant. Of the estimated 476 MW of new investment in solar in 2009, about 61 MW received the cash grant. Presumably, the remaining 415 MW was eligible for the business or residential ITC. In 2009, about 150 MW of geothermal projects received the cash grant, and there were not any large geothermal projects that claimed the ITC. Through March 2010, $2.6 billion had been spent under the cash grant, of which about 85 percent was claimed by wind (Bolinger et al., 2010). See Table 9 for more information on the cash grant.

2.10.2 Abatement

Abatement in 2010 depends on how much wind, solar, geothermal and biomass investment were caused by these policies, and the generation that was replaced. Because the credits only go to new units, the abatement discussion focuses on the technologies that have expanded the most over the past 10 years. According to EIA Form 860, between 2000 and 2009 the wind capacity increased by 32.2 GW, biomass by 2.1 GW, geothermal by 0.4 GW and solar by 0.2 GW. (Note that biomass includes wood, wood-derived fuels, and other biomass. Solar includes solar photovoltaic and solar thermal.) These figures do not account for small generation units and thus understate the capacity growth somewhat, particularly for solar. Nevertheless, it is clear that wind accounts for most—greater than 90 percent—of capacity growth during this time period. Therefore, the discussion of abatement and carbon prices focuses on wind.

Bolinger et al. (2010) suggests that more than half of the wind investment in 2009 would have occurred in the absence of the cash grant. However, this may include the effect of the RPS programs and it may not be representative of the experience before the cash grant. Unfortunately, I am not aware of any studies that have examined the effect of the tax credits on investment and abatement, after accounting for the effect of the RPS programs. Therefore, it is difficult to say conclusively how much abatement has been caused by the tax credits. The most relevant estimate from the literature is Palmer et al. (2010), who conclude that extending the tax credits after they expire in 2016 would be an extremely costly means of reducing emissions.

It is possible to get a rough estimate of the abatement caused by the tax credits by examining states that have a lot of installed wind capacity as well as an RPS program in which the credit price is close to zero. I focus on states with credit prices close to zero stems from the fact that the RPS is not binding in such states.

Texas is the state that most clearly satisfies both requirements; it has the most installed wind of any state, and the RPS credit prices have been close to zero. In 2009 there were approximately 8 GW of installed wind capacity, whereas the RPS required only two GW of capacity. I assume that the tax credits explain the difference--i.e., there would have been zero investment beyond the RPS in the absence of the tax credits. Some of my current research is investigating the validity of this assumption, but the results are not yet available.

After accounting for curtailment, the average wind unit in Texas has had about a 26 percent capacity factor. Therefore, in 2009 the wind generation caused by the tax credits was equal to 13.7 million MWh. If the wind displaced natural gas, this would correspond to 8.2 million mtCO_2. However, Castillo and Linn (2011) suggest that much of the displaced generation was from coal, and that the abatement may be 50 percent higher or perhaps even more.

This calculation yields abatement in Texas, but it is also possible to obtain a very rough estimate of total U.S. abatement due to the production tax credit for wind. EIA (2008) estimates that wind generators were eligible for $526 million in tax credits in 2007. The report also cites an estimate from the Treasury Department that wind generators claimed $666 million in tax credits in 2007. It is possible that some of these credits were earned during prior years of production, which would explain the difference, but there is no direct evidence available. Using the lower number, and the value of the subsidy of $19/MWh, the amount of generation receiving the credit was approximately 28 million MWh.

2.10.3 Implicit carbon price

For a $20/MWh performance-based incentive, and assuming natural gas is displaced, the implicit carbon price is $16/ton (after accounting for the fact that it is valid for 10 years of operation). For wind units that claim the cash grant, the calculation requires additional assumptions about the capacity factor and capital costs. Using the same capacity factor as above, 0.26, and a capital cost of $2000/kW (EIA 2011), the implicit carbon price is $18/ton.

2.11 Nuclear Power Production Tax Credit

The 2005 EPACT provides a production tax credit for the first eight years of operation of $0.018/kWh for the first six million kWh per year, up to a maximum of $125 million per year per 1000 MW of capacity. Given the low fuel and operating costs of modern nuclear plants, the tax credit roughly offsets marginal costs.

The tax credit applies to the first 6 GW of capacity that is newly constructed since 2005. Assuming an 85 percent capacity factor for a new nuclear plant (which is similar to the capacity factor of existing plants, and consistent with Du and Parsons, 2009), the maximum present discounted value of the credit (across all plants) is $4.6 billion.

As a base load generation technology, nuclear may displace coal or natural gas. If nuclear displaces only coal, abatement would be equal to 357 million $mtCO_2$, at a carbon price of $18/$mtCO_2$. For natural gas, the corresponding figures are 214 million $mtCO_2$ and $30/$mtCO_2$.

2.12 Clean Coal Investment Tax Credits

The 2005 Energy Policy Act provides a maximum of $1.3 billion to subsidize 6500 MW of clean coal generation capacity. The program offers a 20 percent investment tax credit to IGCC plants and a 15 percent credit for other advanced coal technologies. The tax credit is offered for the first 3,575 MW of IGCC and 2,925 of other technologies, and priority is given to plants with CCS.

EIA (2009) reports that the value of the credit in 2007 was about $30 million, but this may be because few projects had begun claiming the credit at that time. In 2006, the IRS announced that $1 billion had been awarded for 9 projects, although this figure includes some gasification projects.

In 2008, an additional $1.3 billion was allocated to coal electricity projects, and the credit was increased to 30 percent. To receive the credit, 65 percent of CO_2 must be sequestered. Under this program, $1 billion was awarded in 2009-2010.

2.13 CO2 Capture and Sequestration Tax Credit

2.14 Refined Coal and Indian Coal Tax Credit

According to Environmental Law Institute (2009), the value of the Indian Coal tax credit was very small from 2002-2008. The value of the refined coal tax credit is much higher, around $2 billion per year. The current credit is worth about $6/ton of coal. To qualify, the coal must reduce nitrogen oxides and sulfur dioxide or mercury emissions, but there is no requirement for CO_2 emissions.

3 Transportation Policies

3.1 Bioenergy program for advanced biofuels

Details for this program can be found in the Federal Register (Vol. 75 N. 48, March 12, 2010a). The program includes advanced biofuels and does not include corn starch ethanol. Under the program, payments are made to producers based on actual BTUs of production, the size of the facility, and whether the production represents an increase at the facility or if it represents production at a new facility; the payment is about three times higher for incremental production.

There is not a pre-determined payment rate per unit of production. Instead, the payment rate is determined based on the number of qualified applicants, the amount produced, and the available budget. In fiscal year 2009, $30 million were authorized to the program, and $14.5 million were paid to producers. According to an article in Biodiesel Magazine on January 24, 2011, most of the recipients received amounts less than $500,000. Of the ten largest recipients, half were associated with ethanol production and half with biodiesel. The most recent request for applicants to the program anticipated spending $40 million in fiscal year 2010.

3.2 Renewable Fuel Infrastructure Grant

This program provides grants of up to 33% of the installation cost or a maximum of $180,000 per retail outlet for fuel storage equipment, pumps, and other infrastructure. By comparison, EPA estimates the cost of an E85 pump to be $140,000-170,000. The stated goal of the program is to maximize petroleum displacement, and projects are selected for the grant based on the prevalence of flex fuel vehicles in the area, experience of the business, proximity to other infrastructure, and other factors. As with the other infrastructure programs, it is extremely difficult to disentangle the abatement effects or carbon prices of this policy. The combined budget of this program and a program for "renewable fuel pilot projects" is $1 billion for 2008-2014, of which a maximum of $200 million may go to the pilot projects (as of 2008 no money had been allocated yet). Note that this program covers blends between E10 and E85, and is complementary to the Alternative Fuel Infrastructure Tax Credit.

3.3 Federal fuel excise tax

3.3.1 Background

The federal gasoline tax is currently $0.184/gallon for gasoline and $0.244/gallon for diesel. The tax is imposed on the producer. The tax is used to support the Highway Trust Fund, and is not explicitly motivated by the desire to reduce CO_2 emissions or other pollution.

3.3.2 Abatement

Abatement depends on the effect of the fuel excise tax on retail prices (i.e., pass-through), and the effect of retail prices on consumption. Because the federal tax has changed only a few times over the past 40 years, there is not good evidence of the effect of the federal tax on retail prices. Recent evidence from state taxes suggests that on average retail prices increase one-for-one with state gasoline and diesel taxes (Marion and Muehlegger, 2010). Therefore, I assume that the federal tax is passed through one-for-one to retail prices.

There is a long literature on the effect of gasoline prices on gasoline demand. A distinction should be made between the short run and the long run elasticity of demand. The capital stock is fixed in the short run, meaning that the vehicles people own, the quality and amount of roads, the housing stock, and the location of places of employment and retail business are all fixed. In the long run all of these variables are flexible, which implies that the long run response to a change in gasoline prices is greater in magnitude than the short run response. For this analysis, the long run elasticity is relevant.

The long run elasticity is harder to estimate because it requires either following the same set of individuals over a long period of time, or comparing consumption for similar individuals who live in areas that have persistent differences in gasoline prices. In practice, it is very difficult to find valid comparison groups. Nonetheless, recent research suggests that this elasticity may be around -0.6 (Spiller, 2011), and perhaps even larger in magnitude.

For comparability with the state excise tax analysis below, I use data from 2008, which is the most recent year for which the state-level data are available. In 2008, the average retail gasoline price in the U.S. was $3.15/gallon. Consequently, eliminating the federal gasoline tax would reduce the retail price by 5.8 percent. Using the EPA emission rate for gasoline of 13 kg CO_2/gallon and 2008 highway gasoline consumption of 136 billion gallons, the estimated abatement is 62 million mtCO_2.

Although there is a huge literature on the elasticity of demand for gasoline, estimates for diesel demand are virtually non-existent. The only recent study of which I am aware is Marion and Muehlegger (2008), which estimates the elasticity of demand to the diesel tax to be -0.83. The average diesel price in 2008 was \$3.79/gallon and diesel fuel consumption was 45 billion gallons. Abatement due to the diesel fuel tax was about 34 million $mtCO_2$.

3.3.3 Implicit carbon price

The implied CO_2 tax is straightforward to calculate from the CO_2 emission rates for gasoline and diesel. The same emission rates are used as above. The implicit carbon prices are \$113/$mtCO_2$ for gasoline and \$121/$mtCO_2$ for diesel.

3.4 State fuel excise taxes

3.4.1 Background

State taxes vary widely across states and fuels. In 2008, state gasoline taxes ranged from \$0.075/gallon (Georgia) to \$0.375/gallon (Washington). In 2010, diesel excise taxes ranged from \$0.04/gallon (Florida) to \$0.375/gallon (Washington). Note that many states levy other taxes on diesel and gasoline. For example, the diesel excise tax in California is \$0.18/gallon, but total state taxes are \$0.516/gallon (California has the highest total diesel tax). See Table 7 for gasoline and diesel consumption, as well as gasoline and diesel taxes, by state for 2008.

3.4.2 Abatement

Abatement is estimated similarly to the federal tax, except that the retail prices, state taxes, and highway gasoline consumption for each state are used. The total abatement of eliminating the gasoline tax in each state is equal to 74 million $mtCO_2$. Total abatement for diesel fuel is 28 million $mtCO_2$.

3.4.3 Implicit carbon price

Using the same emission rates as were used to calculate the carbon prices for the federal tax, the carbon prices for the state taxes range from \$3/$mtCO_2$ to \$29/$mtCO_2$ for gasoline, and from \$6/$mtCO_2$ to \$28/$mtCO_2$ for diesel.

3.5 Gas guzzler tax

3.5.1 Background

The tax is levied on cars that have fuel economy below 22.5 mpg. The tax increases from $1,000 per vehicle for cars with fuel economy between 21.5 and 22.5 mpg, to $7,700 per vehicle for cars with fuel economy below 12.5 mpg.

3.5.2 Abatement

Abatement is difficult to assess, and depends on the extent to which the tax causes consumers to substitute away from these vehicles. Note that for manufacturers that meet the CAFE standard—GM, Ford and Chrysler—the tax has no effect on average fuel economy of the vehicles sold by these manufacturers. This is because changing the tax would cause the firms to shift their sales mix so that average fuel economy remains the same. There may be indirect effects of the tax on fuel economy. For example, if the tax causes GM to raise the price of the Corvette, this could affect demand for vehicles not sold by GM, and therefore it could affect the average fuel economy of new vehicles sold. Unfortunately, I am not aware of a quantitative analysis of the abatement caused by the gas guzzler tax (some studies have looked at the effects of a hypothetical tax or fee-bate system, but these studies have not focused on the actual gas guzzler tax).

3.6 Biodiesel fuel credit

3.6.1 Background

There is a federal tax credit of $1/gallon of biodiesel. The tax credit lapsed at the end of 2009, but in December 2010 it was reinstated retroactively and extended through 2011. According to CBO, the foregone revenue from the tax credit was $840 million in 2009.

3.6.2 Abatement

The tax credit and RFS2 provide overlapping incentives for biodiesel. It is difficult to determine whether the RFS2 or the tax credit has been binding. On the one hand, positive RIN prices for biodiesel have been observed at the start of RFS2—even after the extension of the tax credit—which suggests that the policy is binding (i.e., biodiesel production would have been lower had RFS2 not been in place).

On the other hand, the positive prices observed early in RFS2 could be due to uncertainty about aggregate supply of biodiesel, rather than the need for additional incentive created by RFS2 to produce biodiesel beyond the tax credit. In fact, there were some reports that the positive prices in early 2011 were partly because diesel refineries shut down in 2010 in the absence of the tax credit, and had not yet returned on line. The fact that the biodiesel refineries shut down in 2010 indicates that the tax credit is the binding policy. It is not clear proof that the tax credit is binding, however, because the refineries may have been constructed in anticipation of the RFS2 requirements. Therefore, it is unclear which policy is binding.

Given the need to meet the 36 billion gallon per year requirement under RFS2, the biodiesel requirement will probably increase significantly over time. This makes it likely that RFS2 will become binding in the future, but that is highly uncertain.

3.6.3 Implicit carbon price

That said, it is possible to estimate the implicit carbon price using the subsidy amount of $1/gallon and an assumption regarding the abatement caused by one gallon of renewable biodiesel. Under RFS2, biodiesel must provide a lifecycle emissions reduction of 50 percent. If biodiesel has attained this level of abatement in the past, the implicit carbon price is \$179/mtCO_2. The price is correspondingly higher for biodiesel that does not meet this level of abatement.

3.7 Renewable diesel tax credit

Renewable diesel receives the same tax credit as biodiesel, but it is chemically different from biodiesel. The important distinction is that renewable diesel products are just entering market and many have not been tested to meet diesel fuel standards. Because renewable diesel is treated equivalently to biodiesel under RFS2, and because these products are just entering the market, abatement and carbon prices are not evaluated separately from biodiesel.

3.8 Alternative fuel excise tax credit

This program provides a tax credit of $0.50/gallon for fuels that are not included in the alcohol fuel credit or biodiesel credits. The tax credit is available for CNG, LNG, LPG and other fuels. Estimates of the cost of the tax credit could not be found, but EIA estimates of consumption of these fuels are available for 2008. Assuming the credit was claimed for all consumption of these fuels, the total cost was $180 million, of which LPG and CNG account for most of the cost.

3.9 Alternative fuel infrastructure tax credit

Previously, a tax credit covered 50 percent of the cost of installing infrastructure equipment for natural gas, LPG, and other fuels. The credit could not exceed $50,000. In 2011, the tax credit covers 30 percent of the cost, and may not exceed $30,000. In 2010, the total amount of credits claimed was capped at $2 million.

3.10 Alcohol fuel tax credit

3.10.1 Background

There is a federal tax credit of $1.01/gallon cellulosic ethanol, plus a $0.10/gallon credit for small producers. The tax credit is $0.45/gallon for ethanol. According to CBO, the cost to the federal government of the cellulosic portion of the credit was $50 million, and the cost of the corn starch ethanol portion was $5.2 billion in 2009.

3.10.2 Abatement

Because so little cellulosic ethanol is produced for fuel markets in the U.S., I focus on abatement and the implicit carbon price for corn starch ethanol. AEO 2007 forecasted ethanol production of 10.5 billion gallons per year in the absence of RFS2. This cannot be considered to be the amount of ethanol production caused by the tax credit, however, because ethanol is used as an oxygenate and to meet reformulated gasoline requirements under the Clean Air Act and local regulations. In 2007, ethanol demand for these needs was equal to about 3.9 billion gallons. Assuming the same level of demand for 2010, this would imply that the tax credits caused about 6.6 billion gallons of ethanol production in 2010. Under RFS2, corn starch ethanol must achieve a 20 percent emission reduction compared to conventional gasoline. If all of the ethanol produced in 2010 achieved this standard, total abatement was 17 million $mtCO_2$.

3.10.3 Implicit carbon price

The carbon price is calculated under the same 20 percent abatement assumption. The $0.45/gallon tax credit thus corresponds to an implicit carbon price of $173/$mtCO_2$.

3.11 PEV credit

3.11.1 Background

The federal government offers a tax credit of $2500-$7500 to electric vehicles, depending on the battery size. The maximum credit can be earned by a vehicle with 16 kWh of battery capacity. The Chevrolet Volt and Nissan Leaf, which are the first two electric vehicles produced by the major automakers to enter the market, both qualify for the maximum. Many states offer large tax credits or rebates, such as Colorado

($6000) and California ($5000). With current policies, a vehicle could receive a maximum of $13,500 worth of tax credits.

3.11.2 Abatement and revenue

This tax credit was just enacted, and given the very small number of vehicles that are currently on the road, it has not caused a significant amount of abatement. A large number of studies have estimated the abatement of PEVs relative to hybrid electric vehicles or other vehicles with high fuel economy. The analysis of PEV abatement is based on simulations or observations of a very small number of drivers (e.g., Peterson et al., 2009, and Davies and Kurani, 2010). The general conclusion has been that abatement depends strongly on driving behavior and the characteristics of the electric power system. At the extreme, compared to the counterfactual of a Toyota Prius, abatement may be zero in regions of the country that generate a lot of electricity from coal.

Those studies focus on individual vehicles rather than the entire market for new vehicles, however, and they do not account for the effect of the CAFE standard. If the CAFE standard is binding for all firms, the PEV credit may cause no abatement (McConnell and Turrentine, 2010). In practice, the standard has not been binding for all firms, although that could change as the standard becomes more stringent in the future.

3.12 Biorefinery assistance program

The program provides loan guarantees for up to $250 million for retrofitting or constructing biorefineries (Federal Register, Vol. 75 N. 73, 2010b). The loan guarantee can be applied up to 90 percent of the full value of the loan up to $125 million, and 60% above $125 million. Through early 2011, $405 million in loan guarantees have been provided. The Office of Management and Budget expects that the program will be able to leverage at a ratio of about 3 to 1, so given the allocated budget of the program of about $320 million, the program may be able to support about $1 billion in loans.

3.13 Vehicle technology standards

3.13.1 Background

The corporate average fuel economy (CAFE) program was introduced in the mid 1970s to reduce oil imports. The program set separate standards for cars and light trucks that each large automaker had to meet each year (with limited ability to bank and borrow credits). The standards were phased in by the mid 1980s and were stable into the mid 2000s. The standards are jointly regulated by the U.S. EPA and the National Highway Traffic Safety Administration (NHTSA).

Starting in the 2000s, the light truck standard began increasing and the structure of the program changed significantly. Rather than imposing a single standard for all light trucks, each vehicle model has its own standard that depends on its footprint—roughly, its width multiplied by the distance between the axles. Each automaker therefore faced a different standard that depended on the size of its vehicles; automakers that sell smaller vehicles face a higher standard.

In 2007 the EISA changed the program in three important ways. First, the standards increased to 35 mpg by 2016 (34.1 mpg allowing for air conditioning improvements). Figure 3 shows the car and light truck standards from 1978-2016 to provide historical context for the substantial increase in the standards that will take place over the next five years. The standards are the same as California's CO_2 standard in 2016 (Pavley I), and they are designed with the expectation that the California vehicle market will meet those standards (based on modeling of the fleet and forecasting market shares in California). The new standards begin with the 2011 model year, and in the interim, California has set its own standards. In 2011, the EPA and California expect to propose rules for 2017-2025.

The second major change is that the footprint-based standard now applies to cars and light trucks. Third, to reduce overall compliance costs, firms may trade compliance credits.

The EPA and NHTSA have proposed fuel economy and carbon dioxide emission standards for medium and heavy duty trucks, but these regulations will not take effect until model year 2014.

3.13.2 Cost estimates

Aside from the rulemaking analysis by EPA and NHTSA, I am not aware of an analysis that focuses specifically on the new CAFE standards. The EPA estimates that increasing average fuel economy by about 40 percent from 2012-2016 would cost about $52 billion over the entire period.

There is a growing economics literature estimating the cost of the CAFE standards, usually considering a small (e.g., 1 mpg) increase above its current level (Klier and Linn, 2010a). Most of this literature (e.g., Austin and Dinan, 2005, Jacobsen, 2010, and Klier and Linn, 2010b) has concluded that significantly increasing the standard would cost more than the EPA suggests. Cost estimates typically range from $1-5 billion per year for a 1 mpg increase. Although Anderson and Sallee (2011) estimate a much smaller cost of CAFE, their analysis corresponds to a marginal increase in the standard, and thus is not directly comparable to the EPA estimate or the other studies.

The variation in the estimates reflects a number of significant differences in modeling approaches. First, the engineering-based marginal cost estimates for raising fuel economy does not vary much across studies, but the use of the marginal cost data does differ. Most of the economics literature accounts for the fact that the cost estimates are so low that firms would find it profitable to adopt new technology in the absence of a change in the standards. Consistent with the fact that firms do not actually adopt this technology, these studies effectively shift the cost curves up until it is no longer profitable to do so. By comparison, the EPA uses the cost estimates without shifting the curves up, and therefore assumes lower costs.

Second, most of the recent economics literature uses an integrated demand and supply model, in which firms choose vehicle prices (and in some studies other vehicle characteristics) to maximize profits. The supply and demand assumptions vary widely. On the demand side, the demand structure and price elasticities vary across studies. There are also differences in the level of aggregation of vehicle models, where some studies include individual models and other studies aggregate models to the vehicle class-firm level. On the supply side, some studies treat fuel economy as fixed, others allow firms to increase fuel economy by adopting technology, and a few allow firms to trade off fuel economy and performance.

By comparison, the EPA model effectively minimizes the cost of complying with a particular standard. The EPA analysis does not allow for competitive interactions among firms and does not explicitly model consumer demand. Consequently, the EPA analysis would not reflect the heterogeneity across automakers noted in section 1.2. On the other hand, the EPA model has much more technological detail than the economics literature.

A final important difference is consumer valuation of fuel economy. The EPA assumes that consumers treat fuel economy savings equivalently to a change in the vehicle price using a 5 percent discount rate, whereas the economics literature uses a higher discount rate and often assumes that consumers undervalue fuel economy improvements (which is supported by some of the recent literature, e.g., Allcott and Wozny, 2010).

With all of these differences, it is not surprising that the EPA estimates differ from the estimates of the other studies. There is an overall trend in the economics literature towards introducing more technological detail while retaining the rigorous analysis of supply and demand. There may also be something of a downward trend in the cost estimates in the economics literature, but this is still an active area of research.

The final issue related to costs is that the California and CAFE standards overlap, but it is likely that CAFE is binding and not the California regulations. Goulder et al. (2009) conclude that even if the California standards are more stringent, the net effect on emissions may be zero. Automakers can offer multiple versions of a vehicle or adjust prices so that average fuel economy is higher in California than elsewhere, whereas CAFE determines the national average fuel economy.

3.13.3 Abatement estimates

The EPA estimates that the new CAFE standards will reduce emissions by 960 million mtCO_2 over life of vehicles sold during this period. This estimate is based on underlying assumptions about use of the new vehicles compared to the use of used and new vehicles that would have occurred in the absence of the increase in the standards.

3.14 Renewable Fuel Standard (RFS2)

3.14.1 Background

This program follows the initial Renewable Fuel Standard, which began in 2006 and mandated 7.5 billion gallons per year of renewable fuel by 2012. The 2007 Energy Independence and Security Act increased the requirement and changed the structure of the program. The new program is referred to as RFS2.

RFS2 mandates 36 billion gallons of renewable fuel by 2022, including gasoline and diesel substitutes. The program creates several categories of fuel, with separate volume requirements for each. Corn starch ethanol will account for 15 billion gallons per year and advanced biofuels will account for the remaining 21 billion gallons per year. All fuels must reduce GHG emissions by at least 20%, although existing facilities (for which construction began before 2008) are exempt. Advanced biofuels must have at least a 50% reduction, and this category is further divided into cellulosic and biomass-based biodiesel subcategories, which have their own abatement requirements and quantities required. The EPA has described technological pathways which, if followed by a producer, will qualify for each type of fuel. For reference, using advanced processing technologies and natural gas as fuel, corn starch ethanol qualifies as renewable, and sugar ethanol as advanced.

For 2010, RFS2 required 11.25 billion gallons of renewable fuel and 0.95 billion gallons of advanced biofuel. The corn starch ethanol amount increases to 15 billion, after which it is flat through 2022. The other amounts will be determined by EPA. The cellulosic amount was originally set at 100 million for 2010, but was revised down to 6.5 million because of a lack of production capacity.

The program is administered in an analogous way to most RPS programs. A producer or importer generates a Renewable Identification Number (RIN), which is transferred to the purchaser (usually, the blender) of the biofuel when the fuel is sold. The RIN can be traded once the fuel is blended, which allows firms to comply with the RFS by purchasing RINs instead of purchasing biofuel.

3.14.2 Abatement

Estimating abatement in 2010 is not straightforward. Once RFS2 was adopted, it was incorporated in all EIA projections; after the program's adoption, the EIA did not report a forecast with and without the RFS2. The EPA regulatory impact analysis focused on the year 2022, and did not provide interim estimates.

Lacking any estimates in the literature, I instead look at the projections of biofuel production that were made prior to and after the adoption of the RFS2. Specifically, the Energy Information Administration's Annual Energy Outlook (AEO) in 2007 did not include RFS2, whereas the AEO 2008 did include RFS2. Note that EPA used AEO 2007 projections as the counterfactual in its regulatory impact analysis, so this comparison is consistent with the EPA analysis. This comparison is treated with caution, however, because many other factors changed between the two projections, which could have affected the counterfactual amount of ethanol production.

The AEO 2007 projected 10.5 billion gallons in 2010, which is less than the mandated amount of 12 billion gallons, and the estimated actual 2010 consumption of 13 billion gallons. By comparison, AEO 2008, which did include RFS2, predicted ethanol production of 12.5 billion gallons.

These projections can be used to generate an upper bound of the abatement caused by the program in 2010. In principle, the fact that the 2008 projection and the estimated 2010 consumption were greater than the required amount under RFS2 could be due to dynamics of the program—i.e., it was profitable to bring new refineries on line slightly before the program mandates their production. In that case, RFS2 would have caused 2.5 billion gallons of new ethanol production. Note that the other interpretation of the 2008 projection is that RFS2 was not binding, so in that sense this estimate is an upper bound.

Using the emission rate of gasoline and assuming that the ethanol provides a 20 percent reduction, abatement equals 6.5 million $mtCO_2$. This may overstate abatement because nearly all of the production occurred at refineries that were grandfathered into RFS2, and did not have to meet the 20 percent reduction. Because so little production of cellulosic ethanol and biodiesel occurred in 2010, I do not estimate abatement for these fuels.

3.14.3 Implicit carbon price

The implicit carbon price is equal to the RIN price multiplied by the difference between the emission rate of the biofuel and the emission rate of the fuel it replaces. Comprehensive data on RIN prices are hard to find, but there are reports in the trade press that the price was around $1.50 per gallon for biodiesel in late 2010. Note that this price may reflect the absence of the production tax credit. Using a price of $1.50 per gallon and assuming that biodiesel emissions are 50 percent of diesel emissions, the implicit carbon price is $214/$mtCO_2$.

By comparison, ethanol RIN prices were around $0.02/gallon in mid 2010 (at same time, biodiesel was around $0.75/gallon, and was trending in the other direction). This corresponds to a carbon price that is effectively zero, and the implicit carbon price for ethanol was the price calculated above for the alcohol tax credit.

3.15 State RFS programs

3.15.1 Background

Table 8 provides data on the renewable fuel standards for Florida, Iowa, Minnesota, Oregon, and Pennsylvania. The table includes a brief description of the program's requirements, and when the information is available, about enforcement. In general, these states require gasoline to contain 10 percent ethanol. Iowa has a much more aggressive goal—25 percent ethanol by 2019—but the requirement was only 10 percent in 2010.

The table also shows the 2008 gasoline and ethanol consumption for each state, which were obtained from the EIA 2008 State Energy Data System. The final column reports the share of ethanol in total gasoline, which is a rough estimate of the overall state of compliance. For example, ethanol accounts for about 10 percent of gasoline sales in Minnesota, which is the same as the standard. By comparison, Florida is somewhat below its standard, but Florida's program did not take effect until 2010.

3.16.1 Abatement

The state programs overlap with RFS2. The estimate of abatement for RFS2 includes in the baseline the state RFS programs that were in place in 2007. The baseline therefore includes Minnesota and a few other states that have RFS programs (e.g., Washington), but it does not include states that adopted an RFS after 2007, such as Florida. Therefore, to preserve consistency with the RFS2 analysis, it is desirable to estimate abatement for the state RFS programs that are included in the RFS2 baseline. I am not aware of any research on this question, however, and sufficient data are not available to provide an accurate estimate. It is worth noting that virtually all of the ethanol contained in the data in Table 8 was derived from corn starch ethanol.

3.16 CA LCFS

3.16.1 Background

The program sets separate requirements for all gasoline and diesel used in the state. The program mandates a 10 percent reduction in carbon intensity by 2020. Like the federal RFS, the LCFS is based on lifecycle emissions of the fuels, which includes indirect land use effects of growing crops used to produce biofuels.

3.16.2 Abatement and carbon price

As discussed in section 2.2, AB 32 covers the transportation sector and therefore overlaps with the LCFS. Abatement should be estimated in the absence of AB 32, but I am not aware of abatement estimates by CARB as part of the LCFS rulemaking process. There is an assessment of economic costs, but this is based on an accounting-type model, which compares costs of alternative fuels, and then estimates total costs and abatement under different scenarios. The analysis does not include explicit modeling of fuel switching or investment, and therefore is not suitable for this report.

However, CARB does present some analysis of the LCFS as part of its analysis of AB 32. CARB (2010) estimates abatement under the LCFS as compared to the reference case scenario, which includes the federal RFS but not AB 32. CARB estimates abatement of 14 million $mtCO_2$, but does not report an implicit carbon price.

3.17 Federal fleet petrol reduction and alternative fuel increase

An executive order in 2009 requires that federal fleets with more than 20 vehicles must decrease their gasoline consumption by 2 percent per year until 2020. Ultimately, this mandate will result in a 30 percent decrease in gasoline consumption from a baseline of 330 million gallons in 2005 (Alternative Fuel Data Center, Department of Energy). There are exceptions for certain types of fleet vehicles, such as law enforcement and emergency response. Note that there are several other related mandates under executive orders and the 2007 Energy Bill regarding the use of renewable fuel and greenhouse gas emissions.

4 Summary Tables

Tables 9 and 10 provide the requested data for the policies on the short-list. The tables do not include the policies that were discussed above, but which were not included on the short-list. The tables also provide sources for the reported data.

Table 11 lists the electricity and transportation policies for which an implicit carbon price was estimated. The table also shows whether the policy overlaps with other policies.

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