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Supplementary Information for

The Producer Benefits of Implicit Fossil Fuel Subsidies in the United States

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Methods

A. Estimating Producer and Consumer Incidence

The approach for estimating the producer and consumer incidence of implicit fossil fuel subsidies is based on the conceptual framework in Figure 1. Implementation proceeds in five steps: 1) price and quantity data for each of the four fuels; 2) marginal external cost estimates for each fuel; 3) information on pre-existing taxes in order to calculate the net corrective taxes; 4) an approach for generating counterfactual prices and changes in producer and consumer surplus that would emerge with efficient pricing; and 5) estimates of supply and demand elasticities.

A.1. Price and quantity data

All price and quantity data were obtained for the years 2010 through 2018 from the U. S. Energy Administration's (EIA) *Short Term Energy Outlook* annual reports.[1] The quantities of all four fuels—coal, natural gas, gasoline, and diesel—are based on annual domestic consumption in the United States. The price for coal is the annual average cost of coal delivered to electric power plants, which accounts for 93% of all domestic coal consumption in 2018. The price of natural gas is the annual average Henry Hub spot price. The prices for gasoline and diesel are the average retail prices in each year. Table S1 reports all price and quantity data for each year, along with detailed notes on the specific variables taken from the EIA datasets. All unit conversions are undertaken with standard procedures.

A.2. Marginal external costs

Estimates of the marginal external costs (MEC) for each fuel rely on the International Monetary Fund's (IMF) methodology [1] as applied to the United States, with minor exceptions to update the estimates each year.[2] Pollution damages arise through two mechanisms: carbon dioxide that contributes to climate change, and local air pollution that causes a variety of harmful health effects. Climate damages are based on the carbon content of each fuel and valued according to social cost of carbon (SCC) estimates from the U.S. Interagency Working Group [2].[3] For local air pollution (sulfur dioxide, nitrous oxide, and fine particulate matter), integrated assessment modeling is used to translate emissions into ambient concentrations, health effects, and monetary damages. The IMF also estimates the monetary value of transportation related externalities for gasoline and diesel. These include the value of congestion-based travel delays and accident fatalities, along with wear and tear on the road network for heavy-duty, diesel fuel vehicles. Tables S2 and S3 include the MEC estimates for each fuel, externality category, and year.

To provide a sense of the relative magnitudes, Figure S1 illustrates the contribution of each externality type to the overall MEC for each fuel in the most recent year 2018. The majority of coal external costs arise because of adverse health effects from local pollution. The SCC is further broken down between domestic and foreign damages, assuming the former is 10.6% of the latter [3], yet following

[1] The data are available at https:www.eia.gov/outlooks/steo/data/browser/.

[2] Detailed explanations and derivations are included in the original report [1], and raw data used for the IMF analysis are available in supplementary data files at https://www.imf.org/external/np/fad/environ/data/data.xlsx.

[3] The specific numbers used in each year (in 2018$s) from 2018 to 2010 are the following: $48, $46, $44, $41, $40, $38, $36, $34, and $33.

conventional practice, the global number is used for the main estimates [4]. Climate accounts for the largest fraction of external costs for natural gas, and relatively little for gasoline and diesel. The majority of the MECs for gasoline and diesel come from transportation related effects. In all cases, except for natural gas, the majority of the external costs are borne domestically. This is important because one might care about the extent to which the implicit fossil fuel subsidies come at the expense of domestic versus foreign effects.

A.3. Existing fuel and net corrective taxes

Excise taxes represent a constant, per unit tax rate that must be taken into account, as shown in Figure 1b. The United States levies a modest excise tax on coal of $1.10 per ton from subsurface mines, $0.55 per ton from surface mines, and an upper limit in both cases of 4.4% of the coal's selling price. The assumption employed here is an upper-bound estimate of the average tax based on a quantity weighted average of the two rates. Annual data on the quantities of surface and subsurface mined coal are reported in the EIA's *Annual Coal Reports*.[4]

Gasoline and diesel are subject to both state and federal excise taxes. The federal taxes are levied at 18.4 cents and 24.4 cents per gallon for gasoline and diesel, respectively. A quantity weighted average of all state excise taxes was obtained from the U.S. Department of Transportation.[5] For purposes of the analysis here, the annual excise tax for each fuel is the sum of the federal and average state tax.

Other significant categories of taxation are not generally volumetric-based excise taxes. They are nevertheless accounted for in the analysis because they represent existing sources of government revenue collected due to fossil fuel extraction. Excluding them would result in an overestimate of the producer incidence if these taxes were to adjust in ways that would offset other increases in government revenue. The approach is to calculate an additional excise-equivalent tax rate for each fuel.

Coal extracted on federal lands is subject to a federal royalty of 12.5% of gross value for surface mined coal and 8% for subsurface mined coal. The effective royalty rate, however, is substantially lower and estimated at 4.9% of coal's delivered costs [5]. Coal mined on non-federal lands is subject to state severance taxes, which vary considerably among states. For example, the five largest producing states currently have the following severance tax rates: 7% in Wyoming, 5% in West Virginia, 4.5% in Kentucky, and 0% in Pennsylvania and Illinois. Because these rates span the effective federal royalty, and more coal is produced on federal land than within any particular state on non-federal lands, the rate of 4.9% of the delivered value is assumed to apply uniformly for purposes of analysis here. An excise-equivalent

[4] These data are available at https://www.eia.gov/coal/annual/.

[5] The data for 2010 through 2017 are reported in the Federal Highway Statistics table on State Motor-Fuel Tax rates, available at https://www.fhwa.dot.gov/policyinformation/statistics/2017/mf205.cfm. The rates for 2018 are taken from the EIA, available at https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php.

rate for each year is then derived by applying the 4.9% to the delivered price, and converting it to a rate per ton.

The majority of natural gas and oil is extracted from state lands, and the applicable severance taxes also vary considerably across states. The variability applies not only to the rates, but also to the basis upon which the tax applies (e.g., volume vs. value, deductions, and credits). Using characteristics of a representative well, calculations have been made on the effective tax rates for oil and gas in 10 of the highest producing states [6]. The rates used here are a production weighted average across states. Data on each state's production by year is obtained from the EIA.[6] An excise-equivalent rate for each year is then derived by applying the weighted average rate in each year to the annul Henry Hub spot price and converting to a volumetric based rate.

Estimating an excise-equivalent rate for gasoline and diesel requires some additional steps because the weighted average severance tax rate applies to the original extraction of oil. First, the effective severance tax rate for oil extraction in each state [6] is multiplied by the first purchase price within each state and year.[7] This yields a state-specific tax rate per barrel in each year. Second, these rates are averaged across states in each year, weighted by each state's annual production.[8] This yields an estimate of the national average tax per barrel of oil. Third, the fraction of the tax per barrel is attributed to gasoline and diesel using an average of the refinery yields per barrel for each year 2010-2018, which are 46% by volume for gasoline and 29% for diesel.[9] Finally, the rates per gallon are then derived by dividing these amounts by 19.5 and 11.5, which are the national average gallons per barrel for 2018, which vary little from year to year.[10] The end result is an excise-equivalent tax per gallon for both gasoline and diesel for each year, accounting for the upstream taxes on oil.

All taxes and totals for each fuel and year are summarized in Table S4.

The net corrective taxes for each fuel and year are summarized in Table S5.

A.4. Counterfactual prices and measures of incidence

As shown in Figure 1, a key part of the analysis is generating the prices that consumers would pay and that sellers would receive if the externalities were fully internalized. That is, a method is needed to estimate the counterfactual prices p_b^* and p_s^* that establish Q^* as the market clearing condition. The approach taken here is to assume constant elasticity of demand and supply functions. The same approach is used in a study of the welfare and distributional consequences of the shale gas boom in the United States [7]. In addition, research on fossil fuel subsidies generally employs the same approach, but differs by assuming perfect elasticity of supply [1] [8] [9] [10] [11].

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[6] The data are available at https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm.
[7] The first purchase prices for oil by state and year were obtained from the EIA and are available at https://www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm.
[8] Crude oil production by state and year were obtained from the EIA and are available at https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
[9] National average refinery yields were obtained from the EIA and are available at https://www.eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_a.htm.
[10] National average, annual data on the quantity of petroleum products per barrel of oil are available from the EIA at https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil.php.

Supply takes the form $Q = Ap^{\eta}$, where A is a scale parameter, and $\eta > 0$ is the supply elasticity. Demand takes the form $Q = Bp^{\varepsilon}$, where B is a scale parameter, and $\varepsilon < 0$ is the demand elasticity. The following equalities must then hold by definition:

$$Q^* = \left(\frac{p_b^*}{p_b'}\right)^{\varepsilon} Q' = \left(\frac{p_s^*}{p_s'}\right)^{\eta} Q'. \tag{1}$$

This means that the quantities demanded and supplied scale according the ratio of the relevant prices raised to the elasticity parameter, and market clearing requires equality between the quantity demanded and supplied at the efficient equilibrium. The prices are linked according to $p_b^* = p_s^* + MEC$ and $p_b' = p_s' + t$, where t is the pre-existing tax. With this setup, there are four equations and four unknowns $(Q^*, p_b^*, p_s^*, p_s')$ that can be solved for given data on the observed variables (Q', p_b', MEC, t).

Following this procedure for each of the fuels separately, in each year, is sufficient to generate estimates of the different incidence measures, which, as shown in Figure 1, represent the change in consumer and producer surplus. Specifically, the producer incidence can be derived as

$$PI \equiv p_s'Q' - p_s^*Q^* - \int_{Q^*}^{Q'} \left(\frac{Q}{A}\right)^{\frac{1}{\eta}} dQ$$

and the consumer incidence as

$$CI \equiv p_b^*Q^* - p_b'Q' - \int_{Q^*}^{Q'} \left(\frac{Q}{B}\right)^{\frac{1}{\varepsilon}} dQ,$$

where in each case the last term is the integral under the inverse supply and demand function, respectively. Note that this procedure does not account for cross-price effects. While this is the standard, simplifying assumption across the literature on fossil fuel subsidies, it does impose a limitation that requires some caveats. Cross-price effects could be important in cases where fuels are substitutes (as would hold for coal and natural gas in electricity generation, and gasoline and diesel for transportation), but incorporating these into the analysis in a complete way, even with estimates, is not straightforward. One would also need estimates on the rate of substitution away from fuels and not just between them. Additionally, supply side responses are another factor not included but that matter. Fully accounting for these different effects would require a general equilibrium model that simultaneously considers interactions among the four different markets for each fuel.

A.5. Elasticities

A literature review informs the point estimates chosen here and are summarized in Table S6. The aim in each case is to select an estimate that represents a long-run elasticity applicable to the U.S. domestic market. What follows is a brief motivation for each assumption rather than a detailed review of the literature.

The U.S. Department of the Interior's MarketSim model of U.S. energy markets provides a useful resource for some estimates [12]. The model is based on assumptions about long-run demand and supply elasticities for energy, including those for coal and natural gas. Whenever possible, the estimates are based on the empirical, peer-reviewed literature, and several are the same as those used in the EIA's

National Energy Modeling System (NEMS). The MarketSim documentation also provides a range of estimates from the literature that make for useful comparisons.

The MarketSim elasticity of demand for coal (in absolute value) is 1.47, which is the lower estimate in Jones [13] based on data from 1960 through 2011. This provides a reference point for the estimate used here of 1.7, which is slightly higher to reflect recent shifts in the composition of electricity generating units toward natural gas that are likely to increase the demand elasticity for coal. As a further point of comparison, Knittel et al. [14] provide an estimate based on short-term switching decisions at electricity generating units, and they find estimates of 1.7 and 2.1 for units that are independently owned or not, respectively.

MarketSim also provides the basis for choosing the demand elasticity for natural gas. Separate estimates are reported for the commercial, residential, and industrial sectors, and the starting point used here is a 2018 quantity-weighted average, after combining electric power with the industrial sector. This produces and estimate of 0.42, which is increased to 0.55 in order to reflect the increasing availability of renewable sources of energy as a substitute. As another point of comparison, Hausman and Kellogg [7] estimate a long-run, natural gas demand elasticity in the United States that includes all sectors of 0.4.

A relatively large literature produces estimates of demand elasticities for gasoline and diesel, and there are several published meta-analyses to drawn on. A focal point in the literature tends to be the analysis by Epsey [15], which finds a long-run estimate of 0.58 based on over 100 studies covering the period 1929 through 1993. Lin and Prince [16] provide a review that includes more recent meta-analyses with somewhat higher estimates, whereas Dahl [17] considers a mix between short- and long-run effects that produce a somewhat lower estimate for the United States. The gasoline estimate used here is 0.63, which is somewhat higher than the Epsey [15] focal point to reflect increased availability of more fuel efficient cars. The estimate used for diesel, however, remains at 0.58, because there are fewer substitutes for heavy duty diesel vehicles, along with suggestive evidence in the literature the demand for diesel is less price elastic.

With respect to transportation fuels, research finds that the elasticity of the tax component is greater than that for the price inclusive of the tax [18] [19], and the difference appears especially pronounced for a carbon tax [20] [21]. This finding suggests that using price elasticity studies might provide an underestimate of the demand elasticity arising from a corrective tax. To the extent this holds, the ultimate result here would be an underestimate of the producer incidence.

In general, relatively less is known about supply elasticities. Two of the estimates used here are taken directly from MarketSim: a supply elasticity of 1.8 for coal, and an estimate of 1.6 for natural gas. While there is little evidence on the supply elasticity of coal, recent changes in the natural gas industry have stimulated research on estimating natural gas elasticities. For example, the Energy Modeling Forum [22], which averages across many different models, provides a 2015 range of estimates between 1.55 and 1.74 for the United States. Because these numbers fall on either side of the MarketSim estimate of 1.6, they help to build confidence in the assumption. As another point of comparison, Hausman and Kellogg [7] estimate a long-run supply elasticity of natural gas drilling (in contrast to production) of 0.81, and Anderson et al. [23] find a close relationship between drilling and production elasticities under certain conditions and when reservoir pressure is an important feature of production, as with natural gas.

Regarding the supply elasticities of gasoline and diesel, it is common for researchers to assume perfect inelasticity in the short-run or perfect elasticity in the long-run. While these assumptions have their simplifying appeal, neither of the two limiting cases is likely to hold in practice for the United States.

Both elasticities are also closely connected to the supply of oil, as both gasoline and diesel are refined petroleum products. The estimates used here, which are the same as those assumed by Austin and Dinan [24] and CBO [25], are 2.0 for both gasoline and diesel. Rather than being based on econometric estimates, these elasticities are derived from EIA forecasts of prices and quantities supplied within the EIA's NEMS model. This means that the elasticity estimates for gasoline and diesel account for upstream changes in the production of oil, which is supplied is a world market.

A.6. Results

Combining all of the preceding steps produces estimates of the overall subsidy for each fuel and separate measures of producer and consumer incidence. Figure S2 shows the overall subsidy for each year and broken out by fuel type. The total amount does not vary much year-to-year, with a range between \$538 and \$592 billion. The complete set of results, including producer and consumer incidence for each fuel and year, are reported in Table S7.

A.7. Comparison with pass-through rates from other studies

A growing number of studies estimate pass-through rates as a measure of incidence without needing to make assumptions about elasticities. Although none directly match the setting studied here, they provide useful points of comparison that reinforce the reasonableness of the relative elasticity estimates, which ultimately determine the pass-through rates and the producer incidence. See Table 1 for the implied pass-through rates in 2018, which change little from year to year.

Note that pass-through estimates used in the present analysis are defined as $(p_b^* - p_b')/(MEC - t)$, which is the ratio of the change in the price buyers pay to the net corrective tax. These are not the marginal, pass-through rates that solve out to the standard formula of $1/(1 + \varepsilon/\eta)$. They are instead the effective pass-through rates based the discrete (non-marginal) changes implied by the magnitudes of the net corrective taxes. The effective pass-through rates are greater than the marginal rates.

Focusing on the market for coal in electricity generation, Preonas [26] finds pass-through rates from an implicit carbon tax that range between .75 and 1, and Hughes and Lange [27] find similar estimates that vary between regulated and deregulated electricity markets. Using variability is spot market prices, Chu et al. [28] find significantly lower rates for coal and rates of around .8 for natural gas.

More pass-through studies focus on the transportation fuels. Marion and Muehlegger [29] find evidence of near complete pass-through of gasoline and diesel taxes, but the effect depends on market conditions and the interaction with other forms of regulation. Knittel et al. [30] use cost variation induced by the renewable standards and find full pass-through to wholesale prices of gasoline and diesel, but little evidence of pass-through to retail prices. In a comparable study, Burkhardt [31] finds lower pass through to wholesale prices at rates of .76 and .5 for gasoline and diesel, respectively. When considering a carbon tax on oil refineries, Muehlegger and Sweeney [32] find nearly complete pass-through, with much heterogeneity among refineries, while Ganapati et al. [33] find lower rates ranging between .24 and .34. Finally, Heal and Schlenker [34] use an alternative numerical approach and find an initial pass-through rate in the oil market of between .7 and .8 that declines over time.

B. Attribution to Producers

This section provides details on the methods employed for attributing portions of the estimated producer incidence to particular fossil fuel producers. It begins with a framework for making necessary assumptions about supply chain pass-through rates, followed by company-specific data collection and benefit estimates.

B.1. A Model of supply chain pass-through

The aim here is to estimate the portion of producer incidence that directly benefits the most upstream producers, that is, the actual suppliers of the fossil fuels. A key input for making such a calculation is an understanding of how the producer incidence is distributed at difference points along the supply chain. In general, this will depend on a range of factors, including market power, bargaining outcomes, and the nature of production and distribution processes that affect the supply and demand for factor inputs. A simple model nevertheless helps to fix ideas and illustrate the determining role of how taxes might be expected to affect upstream and downstream margins. A similar initial setup has also been used in other research to motivate a sufficient statistics approach for estimating tax incidence along the vertical supply chain for cigarettes [35].

Consider a supply chain consisting of an upstream and downstream firm. The upstream firm produces a commodity (e.g., coal, natural gas, or oil), of which k units are needed to produce the final good. In the cases of coal and natural gas, the setup can be simplified to $k = 1$, but introducing the parameter captures a key feature in the supply chain for diesel and natural gas, which are final goods derived from the refining of oil. Without loss of generality, the marginal costs of producing the intermediate good are set to zero, and the upstream firm sells k units of its good to the downstream firm at price p_u. The downstream firm receives an after-tax price of p_s for the final good, while consumers pay a tax-inclusive price of p_b. The downstream firm's margin is therefore $m_d = p_s - p_u$.

Now consider a per unit tax τ on the final good or an equivalent tax on the intermediate commodity of τ for k units. Regardless of which party must remit the tax, the following identity will hold

$$\tau = p_b(\tau) - p_u(\tau) - m_d(\tau), \tag{2}$$

where each term is written as a function of the tax. It is straightforward to confirm that $p_b = p_s$ in the special case of $\tau = 0$. Differentiating (2) and rearranging yields

$$1 - p_b^\tau = -p_u^\tau - m_d^\tau, \tag{3}$$

where the superscripts indicate the differential with respect to a change in τ. Because p_b^τ is the pass-though rate to consumer prices, the left-hand side of (3) is the producer incidence per unit of the final good. The right-hand side, which itself equals p_s^τ, is the sum of changes to the upstream and downstream margins, respectively.

The share of the per-unit producer incidence attributable to the upstream firm, defined as I_U^P, is therefore

$$I_U^P = \frac{-p_u^\tau}{1 - p_b^\tau} = \frac{p_u^\tau}{p_u^\tau + m_d^\tau} = \frac{p_u^\tau}{p_s^\tau}. \tag{4}$$

This implies that I_U^P is simply the proportion of the combined reduction in prices (margins) falling on the upstream firm. If, for example, the downstream margin does not change (i.e., $m_d^\tau = 0$), then $I_U^P = 1$, and the incidence falls entirely on the upstream firm. If, however, the upstream margin does not change (i.e., $p_u^\tau = 0$), then $I_U^P = 0$, and the incidence falls entirely on the downstream firm.

More generally, the fundamental insight of equation (4) is that expectations about how upstream and downstream prices are likely to change with a tax are sufficient for attribution of the producer incidence to upstream suppliers. This observation helps motivate assumptions about I_U^P within the supply chains for each fuel, despite a lack of existing research focused on producing such estimates.

B.2. Coal

The supply chain for coal delivered to U.S. power plants has two key links: production at mines and transportation to power plants. The majority of coal is delivered via rail transport, and a well-documented feature of this market is that rail carriers have a substantial amount of market power, where mark-ups depend on the degree of competition, natural gas prices, and electricity market regulation [36] [27] [26]. The question of interest here is: to what extent would imposing a tax on coal differentially affect the production and transportation margins?

One way to get a sense for the answer is to leverage the insight of Cullen and Mansur [37] that the difference between coal and natural gas prices operate like an implicit carbon tax in the electricity sector. Figure S3 shows how the average, real price of delivered coal and natural gas has changed over time since 2010.[11] The price of coal has declined, but the price of natural gas has declined more, with relatively large fluctuations. Interpreting the difference between these trends as variation in an implicit carbon tax (larger when the price of natural gas is relatively lower), the next series to investigate is rail delivery prices for coal over the same period. Figure S4 shows trends in the average, real price per ton of coal delivered from each of the significant coal basins and for a U.S. weighted average.[12] Rather than decrease, the national average has increased or remained relatively constant. The only basins that have seen prices decline are Central Appalachia somewhat and Uinta substantially, and the two regions produced only 10% and 4% of U.S. coal in 2018, respectively.

The preceding analysis provides suggestive evidence that transportation margins for the United States as a whole would not change much with imposition a corrective tax on coal. Indeed, the evidence suggests that transportation prices might even increase in the larger producing regions such as the Powder River Basin. This implies that most or all of the producer incidence would be expected to fall on the upstream coal producers through lower mine mouth prices. The assumption here, therefore, is that I_U^P is between .75 and 1 for coal.

B.3. Natural gas

The supply chain for natural gas in the United States begins with domestic production at wells. The natural gas is then transported through gathering pipelines to processing plants, after which it is shipped

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[11] The coal prices are those described previously in the notes to Table S1. Delivered natural gas prices were obtained from the EIA, variable N3045US3, and converted to equivalent units using the approach described in the notes to Table S1. Prices are converted form nominal to real using the GDP deflator from the Bureau of Labor and Statistics.
[12] These data are taken from Table 2 of the EIA's report on the Coal Transportation Rates to the Electric Power Sector, available at https://www.eia.gov/coal/transportationrates/.

through additional pipelines to storage facilities and distribution hubs, where it is priced and traded. Because of the need for an interconnected pipeline network, natural gas is almost strictly a North American commodity, in contrast to oil (see below).

The benchmark price for natural gas is the Henry Hub spot price, which also provides the basis of the analysis for estimating incidence of the subsidy. In this setting, the relevant portion of the supply chain consists of the resource producers at wells, along with the processing and transportation stages up to the point of delivery at trading hubs. Unfortunately, recent data on wellhead prices are not available because the EIA stopped reporting them in 2012. Figure S5 nevertheless compares the average U.S. wellhead prices and Henry Hub spot prices since 1997.[13] The two series move very closely together, with a correlation of 0.99. Moreover, there is very little margin between the wellhead and spot prices, indicating relatively little scope for changes in the downstream margins.

Limitations of drawing conclusions based on these two sources of data are that much has changed in the natural gas industry in recent years, for which data are not available, and that there is no "quasi-experiment" for considering a corrective tax. Nevertheless, the close relationship between wellhead and spot prices helps support an assumption for natural gas that I_U^P is between .75 and 1, in parallel with the assumption for coal.

B.4. Gasoline and Diesel

The U.S. supply chain for gasoline and diesel has several key links: 1) crude oil is supplied from a combination of domestic wells and imports, 2) oil is delivered to refineries, where it is processed into several different petroleum products, including gasoline and diesel, 3) the fuels are transported to bulk storage facilities, and 4) they are eventually transported to fueling stations, where sold to retail consumers. In contrast to the approach to coal and natural gas, which are both primary energy sources, attribution of the implicit subsidy benefits for gasoline and diesel requires tracing the production upstream to oil producers. As described below, this procedure is based on the amount of oil a company produces in proportion to the world's supply.

A well-studied feature of these linked oil and transportation fuel markets is that changes in crude oil prices are almost fully passed through to retail gasoline and diesel prices. Figure S6 shows the close correlation, plotting the trend in average spot prices for West Texas Intermediate crude (the standard benchmark) and retail prices for gasoline and diesel.[14] It is easy to see how the prices move together quite closely, showing some evidence of greater pass-through of price increases than decreases [38]. As with natural gas, the trends may be interpreted as providing little scope for changes in the downstream margins due to a tax on fuels, resulting in greater upstream incidence.

The upstream incidence assumption made here for oil seeks to reflect the limited scope for changes in the downstream gasoline and diesel margins, but also the relative elasticity oil supply, which is determined in a world market. It is assumed that I_U^P is between .5 and .75 for upstream domestic oil producers, except in cases where the supplier is vertically integrated along the entire supply chain. Hastings [39] and Hastings and Gilbert [40] find evidence of market power in the gasoline market based on the extent of vertical integration. Some companies produce oil, own refineries, and sell branded fuels

[13] The Henry Hub spot prices are those described previously in Section A.1. Natural gas wellhead prices were obtained from the EIA and are available at https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_FWA_DMcf_a.htm.
[14] The retail gasoline prices are described previously. The oil prices were obtained from the EIA and are available at https://www.eia.gov/dnav/pet/PET_PRI_SPT_S1_A.htm.

at their own filling stations, and it is assumed that I_U^P is between .75 and 1 in these small number of cases (see below).

B.5. Estimation of producer-specific benefits

The next step for attribution is obtaining estimates of supply from producers, where the focus here initially is on domestic production. For coal and natural gas, U.S. production comprises the supply, whereas the supply for oil is met with both domestic production and imports integrated as part of the world market for oil.

Two sources of data are used to provide estimates for 2017 and 2018. First is the EIA's listing of major coal producers as part of its *Annual Coal Report*, which in 2018 includes 23 companies listed by name that account for 88% of domestic production.[15] Production for most of these same companies for 2017 was obtained from the same report a year earlier. Tables S8 and S9 report all coal company specific data and estimates for 2017 and 2018.

The second source of data is the Ernst & Young *U.S. Oil and Gas Reserves Production Study* for the years 2018 and 2019. The study compiles information from annual reports of the 50 largest publicly traded oil and gas companies.[16] A useful feature of the report is company-specific data on production from domestic natural gas and oil reserves. The 50 companies account for 44% of all domestic natural gas production in each year. The same 50 companies account for approximately 40% of all domestic oil production in both years, which translates into 6.4% and 7.3% of global production in 2017 and 2018, respectively. Five of these companies own refineries and sell their own branded gasoline and diesel (BP, Chevron, Exxon Mobil, Marathon Oil, and Royal Dutch Shell) and therefore have the higher incidence rates, as described above. Tables S10 and S11 report all company-specific data and estimates for natural gas and oil producers for 2017 and 2018.

The benefit to company i for the supply of a given fuel can be written as

$$B_i = \frac{x_i}{X} \times PI \times I_U^P, \quad (5)$$

where x_i is the company's supply, X is the relevant aggregate supply, PI is the estimated aggregate producer incidence, and I_U^P defined above is the portion of the incidence attributable to upstream suppliers. Note that X is defined as U.S. domestic production for coal and natural gas, which defines the

[15] Those included produced at least 5 million tons in 2018. See Table 10, available at https://www.eia.gov/coal/annual/.

[16] The largest companies are determined based on oil and gas reserves at the end of 2018, and the report is available at https://assets.ey.com/content/dam/ey-sites/ey-com/en_us/news/2019/09/ey-us-oil-and-gas-reserves-and-production-study.pdf. The 2017 report was obtained from Ernst & Young upon request.

relevant supply for U.S. consumption.[17] For gasoline and diesel, however, the quantities used are based on upstream oil production where X is global production. The oil proportions are able to partition the incidence for gasoline and diesel because both fuels are derived in roughly fixed proportions from a barrel of oil.[18] The key idea of equation 5 is that the aggregate estimate of the producer incidence is apportioned to upstream suppliers according to estimates of I_U^P, and then split among individual suppliers according to their proportion of aggregate supply.

Tables S8 through S11 report the 2017 and 2018 estimates of equation 5 for all companies, fuels (coal, natural gas, and combined for gasoline and diesel), and scenarios with the range of values for I_U^P. Figures 3 and 4 in the main text focus on the average across scenarios for the most recent year 2018. The additional set of results in Figure 5 for the world's ten largest oil producers are based on additional data for each company's worldwide production in 2018.[19]

B.5. Ratio with Net Income

The final set of results place the company specific magnitudes in context. While the numbers themselves are substantial, it is useful to compare them to a key indicator of a company's financial performance. Net income is the standard measure of a company's bottom line. It measures total revenue from production minus all costs, which include administrative and operating expenses, depreciation, interest, taxes, and other expenses. The Ernst & Young report conveniently includes data on the net income of all companies based exclusively on continuing operations of U.S. domestic production (see Tables S10 and S11). The data used in Figure 5a is simply the ratio of the average combined benefit over net income, averaged across 2017 and 2018 when data are available.

Data on net income is more limited for coal companies, many of which are privately owned and/or were undergoing bankruptcy proceedings during the period under study. A review of annual reports when available produced data for 11 companies that primarily focus on coal production (see Tables S8 and S9). The net income for coal companies is based on all continuing operations and not just production within the United States. In many cases, the reporting is such that separating out domestic operations is not immediately clear, yet the coal companies for the most part focus exclusively on domestic production. Vistra Energy is excluded from this portion of the analysis because it is primarily an electricity supplier rather than a coal producer. Moreover, consistent data on net income is available for Peabody energy only for 2018. Again, the data used in Figure 5b is simply the ratio of the average benefit over net income, averaged across 2017 and 2018. The two outliers censored at the high end are Hallador Energy and NACCO Industries, which have ratios of 6.0 and 11.5.

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[17] For the years 2017 and 2018, the EIA reports domestic production of coal at 774,609 and 756,167 thousand short tons, and domestic production of natural gas at 27,306,308 and 30,588,702 bcf.

[18] For the years 2017 and 2018, the EIA reports, the EIA reports global oil supplies at 35,821.83 and 36,770.1 million barrels.

[19] These data are reported by GlobalData analysists and are available online at https://www.offshore-technology.com/features/companies-by-oil-production/.

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Supplementary Figures

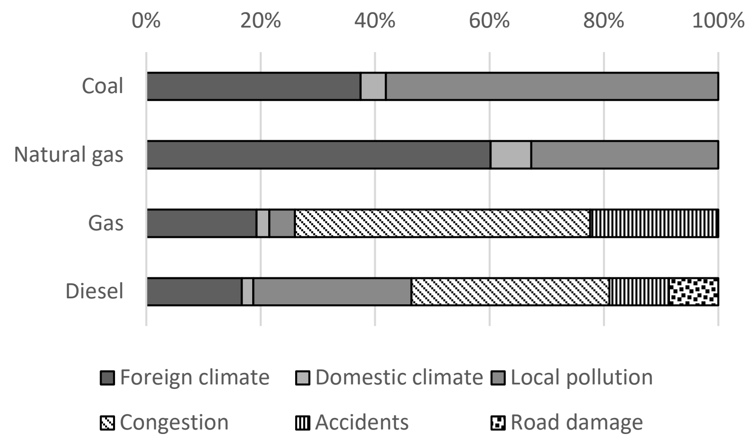

Figure S1: Percentage contribution of each externality type to the overall marginal external cost of each fuel in 2018. The proportions vary little from year to year (see Tables S2 and S3).

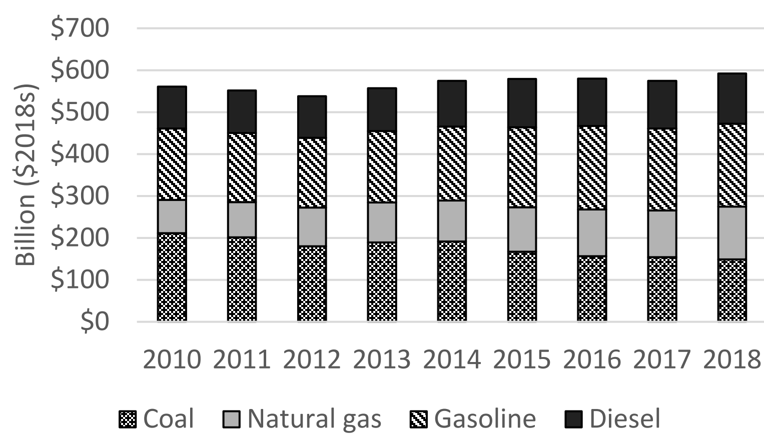

Figure S2: The total implicit subsidy across all four fuels in each year. Data for each fuel type corresponds to the numbers reported in Table S7.

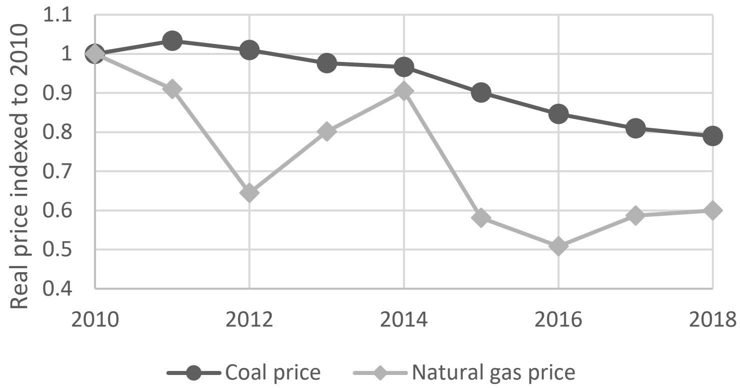

Figure S3: The real price trend of coal and natural gas delivered to U.S. electric power plants, 2010-2018

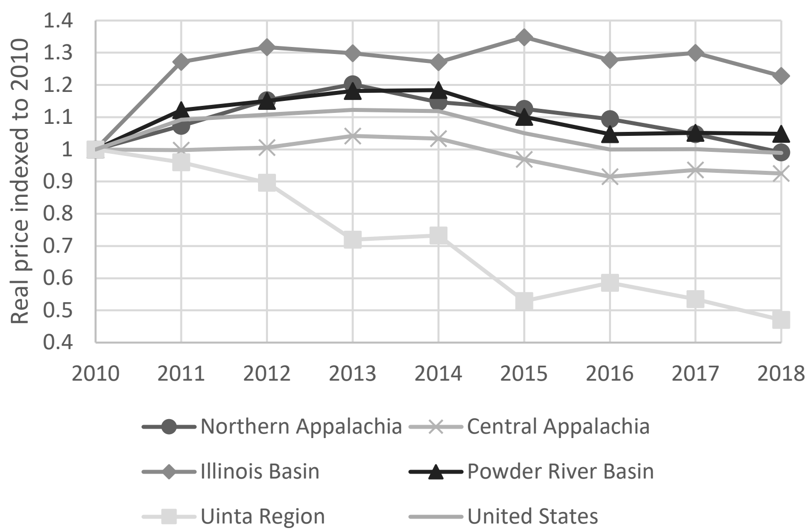

Figure S4: The real price trend of transporting coal to electric power plants in dollars per ton from each basin and a weighted average for the United States, 2010-2018

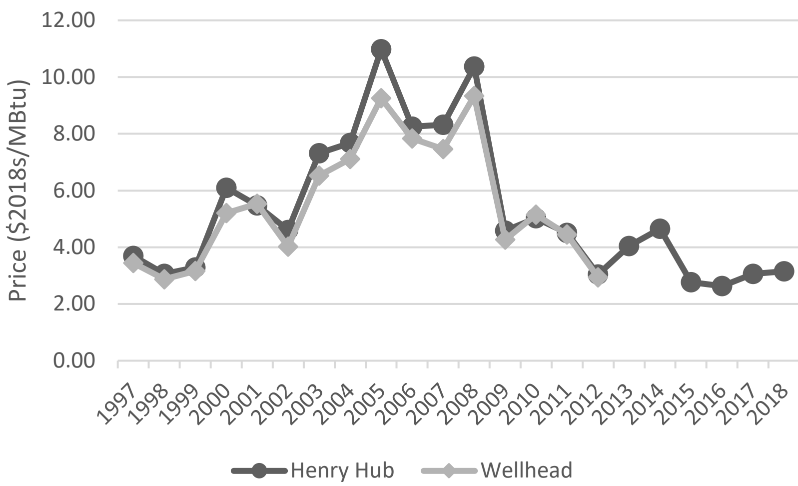

Figure S5: The real natural gas price series for the Henry Hub spot and U.S. average wellhead for years when data are available since 1997

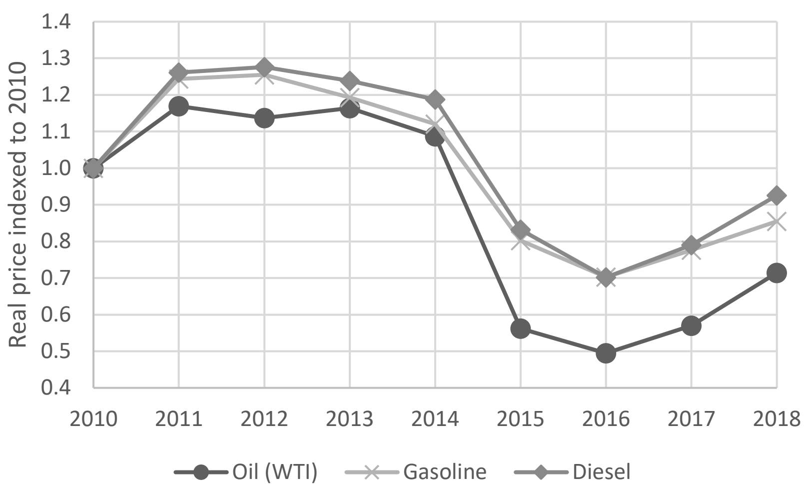

Figure S6: The real price trend of West Texas Intermediate (WTI) spot for crude oil and the U.S. retail prices of gasoline and diesel

Supplementary Tables

Table S1: Price and quantity data for coal, natural gas, gasoline, and diesel for U.S. consumption, 2010-2018.

	Coal		Natural Gas		Gasoline		Diesel	
Year	Million tons	$/ton	Billion cubic feet	$/1000 cubic feet	Billion gallons	$/gallon	Billion gallons	$/gallon
2018	688.11	$39.63	30,075.31	$3.26	143.01	$2.73	63.56	$3.18
2017	716.86	$39.73	27,145.88	$3.09	142.98	$2.42	60.28	$2.65
2016	731.07	$41.11	27,369.23	$2.61	143.22	$2.15	59.60	$2.31
2015	798.11	$43.37	27,243.85	$2.73	140.70	$2.43	61.25	$2.71
2014	917.73	$46.36	26,593.37	$4.53	136.76	$3.36	61.89	$3.83
2013	924.44	$45.72	26,155.07	$3.83	135.56	$3.51	58.68	$3.92
2012	889.19	$46.57	25,468.70	$2.82	133.46	$3.63	57.51	$3.97
2011	1002.95	$46.87	24,477.42	$4.09	134.18	$3.53	59.77	$3.85
2010	1048.51	$45.06	24,086.79	$4.49	137.86	$2.78	58.26	$2.99

Notes: All data are from the EIA. All prices are reported in nominal values. The original source data for the quantities of coal, natural gas, gasoline, and diesel are EIA variable IDs “steo.cltcpus_ton.a”, “steo.ngtcpus.a”, “pet.mgfupus1.a”, and “pet.mdiupus.a.” The original source data for prices are EIA variable IDs “steo.cleudus.a”, “steo.nghhuus.a”, “steo.mgrarus.a”, and “steo.dsrtuus.a.” When converting the prices for coal and natural gas from the base of British thermal units (Btus) to short tons and cubic feet, respectively, information is used on the estimated heat rates of coal and natural gas consumed in each year. The annual heat rates for coal and natural gas are included in the EIA's Monthly Energy Reviews in Tables A5 and A4, respectively.

Table S2: Marginal external cost estimates for coal and natural gas consumption in the United States, 2010-2018.

	Coal (per million tons)			Natural Gas (per 1000 cubic feet)		
Year	Carbon dioxide	Local pollution	Total	Carbon dioxide	Local pollution	Total
2018	\$91.88	\$127.45	\$219.33	\$2.92	\$1.42	\$4.34
2017	\$87.65	\$124.71	\$212.37	\$2.78	\$1.39	\$4.17
2016	\$84.50	\$123.40	\$207.90	\$2.66	\$1.36	\$4.02
2015	\$79.33	\$122.28	\$201.61	\$2.50	\$1.35	\$3.84
2014	\$76.84	\$121.82	\$198.65	\$2.39	\$1.33	\$3.72
2013	\$72.92	\$119.01	\$191.93	\$2.27	\$1.30	\$3.57
2012	\$69.66	\$117.14	\$186.80	\$2.16	\$1.27	\$3.43
2011	\$66.47	\$115.27	\$181.74	\$2.05	\$1.24	\$3.29
2010	\$63.95	\$114.46	\$178.41	\$1.95	\$1.22	\$3.17

Notes: All dollar values are nominal. Carbon dioxide represents the damages associated with the SCC. Local pollution represents the public health costs associated with sulfur dioxide, nitrous oxide, and fine particulate matter emissions.

Table S3: Marginal external cost estimates for gasoline and diesel consumption in United States, 2010-2018.

	Gasoline (per gallon)					Diesel (per gallon)					
Year	Carbon dioxide	Local pollution	Congestion	Accidents	Total	Carbon dioxide	Local pollution	Congestion	Accidents	Road damage	Total
2018	\$0.42	\$0.09	\$1.00	\$0.43	\$1.94	\$0.47	\$0.70	\$0.87	\$0.26	\$0.22	\$2.51
2017	\$0.40	\$0.08	\$0.98	\$0.42	\$1.88	\$0.45	\$0.68	\$0.85	\$0.25	\$0.21	\$2.44
2016	\$0.38	\$0.08	\$0.96	\$0.42	\$1.84	\$0.43	\$0.67	\$0.83	\$0.25	\$0.21	\$2.39
2015	\$0.36	\$0.08	\$0.95	\$0.41	\$1.80	\$0.40	\$0.66	\$0.82	\$0.25	\$0.21	\$2.34
2014	\$0.34	\$0.08	\$0.94	\$0.41	\$1.77	\$0.39	\$0.65	\$0.82	\$0.24	\$0.20	\$2.30
2013	\$0.33	\$0.08	\$0.92	\$0.40	\$1.73	\$0.37	\$0.64	\$0.80	\$0.24	\$0.20	\$2.25
2012	\$0.31	\$0.08	\$0.91	\$0.39	\$1.69	\$0.35	\$0.63	\$0.79	\$0.24	\$0.20	\$2.20
2011	\$0.30	\$0.08	\$0.89	\$0.39	\$1.65	\$0.33	\$0.62	\$0.77	\$0.23	\$0.19	\$2.15
2010	\$0.28	\$0.08	\$0.87	\$0.38	\$1.61	\$0.32	\$0.61	\$0.76	\$0.23	\$0.19	\$2.10

Notes: All dollar values are nominal. Carbon dioxide represents the damages associated with the SCC. Local pollution represents the public health costs associated with sulfur dioxide, nitrous oxide, and fine particulate matter emissions. Congestion represents traffic delays, accidents represents roadway fatalities, and road damage represents wear and tear on roadways from heavy-duty diesel vehicles.

Table S4: Pre-existing taxes for each fuel and year, including excise and excise-equivalent taxes

	Coal ($/ton)			Natural gas ($/1000 cubic feet)			Gasoline ($/gallon)			Diesel ($/gallon)		
Year	Excise	Other equivalent	Total	Excise	Other equivalent	Total	Excise	Other equivalent	Total	Excise	Other equivalent	Total
2018	$0.77	$1.94	$2.72	$0.00	$0.16	$0.16	$0.45	$0.11	$0.56	$0.52	$0.11	$0.63
2017	$0.77	$1.95	$2.71	$0.00	$0.16	$0.16	$0.46	$0.09	$0.55	$0.52	$0.09	$0.61
2016	$0.76	$2.01	$2.78	$0.00	$0.14	$0.14	$0.43	$0.07	$0.50	$0.49	$0.07	$0.57
2015	$0.77	$2.13	$2.90	$0.00	$0.15	$0.15	$0.43	$0.08	$0.51	$0.48	$0.08	$0.56
2014	$0.78	$2.27	$3.05	$0.00	$0.25	$0.25	$0.41	$0.15	$0.56	$0.48	$0.16	$0.65
2013	$0.77	$2.24	$3.01	$0.00	$0.22	$0.22	$0.40	$0.17	$0.57	$0.47	$0.18	$0.65
2012	$0.77	$2.28	$3.05	$0.00	$0.16	$0.16	$0.40	$0.16	$0.56	$0.46	$0.17	$0.63
2011	$0.77	$2.30	$3.06	$0.00	$0.24	$0.24	$0.40	$0.16	$0.56	$0.47	$0.17	$0.64
2010	$0.77	$2.21	$2.98	$0.00	$0.28	$0.28	$0.40	$0.13	$0.53	$0.47	$0.14	$0.61

Notes: All dollar values are nominal. The coal excise tax is based on a weighted average of surface and subsurface tax rates. The gasoline and diesel excise tax rates are based on the sum of the federal tax rates and a weighted average of the state tax rates. The other equivalent taxes are estimates of the per volume tax rates based on federal royalty and state severance tax rates. The methods are described in the text. Total is the sum of the two tax rates for each fuel. There are no excise taxes for natural gas.

Table S5: The net corrective taxes for each fuel and year

Year	Coal ($/ton)	Natural gas ($/1000 cf)	Gasoline ($/gallon)	Diesel ($/gallon)
2018	$216.61	$4.18	$1.38	$1.88
2017	$209.65	$4.01	$1.34	$1.83
2016	$205.12	$3.89	$1.33	$1.82
2015	$198.71	$3.70	$1.29	$1.77
2014	$195.61	$3.47	$1.21	$1.66
2013	$188.92	$3.35	$1.16	$1.61
2012	$183.75	$3.27	$1.13	$1.57
2011	$178.67	$3.05	$1.09	$1.51
2010	$175.43	$2.88	$1.07	$1.49

Notes: The net corrective taxes are the difference between the marginal external cost (MEC) estimates for each fuel and year (Table S2 and S3) and the total pre-existing taxes (Table S4).

Table S6: Demand and supply elasticity assumptions for all fuels, including the ranges employed for sensitivity analysis

Fuel	Demand	Supply
Coal	-1.75 [-0.88, -2.63]	1.9 [0.95, 2.85]
Natural gas	-0.55 [-0.28, -0.83]	1.6 [0.80, 2.40]
Gasoline	-0.63 [-0.32, -0.85]	2.0 [1.00, 3.00]
Diesel	-0.58 [-0.29, -0.87]	2.0 [1.00, 3.00]

Notes: The numbers are intended as long-run elasticities, with justifications provided in the text. The numbers provided in brackets are the 50% decrease and increase estimates used in the sensitivity analysis referred to as the low and high pass-through rate scenarios in Table 1.

Table S7: The annual incidence measures and the total implicit subsidy amount for coal, natural gas, gasoline and diesel in the United States, 2010-2018, in billions of dollars

	Coal			Natural gas			Gasoline			Diesel		
Year	CI	PI	Subsidy	CI	PI	Subsidy	CI	PI	Subsidy	CI	PI	Subsidy
2018	$27	$9	$149	$84	$17	$126	$147	$29	$198	$90	$16	$119
2017	$27	$9	$154	$71	$14	$111	$139	$26	$196	$80	$13	$113
2016	$27	$9	$157	$67	$13	$111	$135	$25	$200	$77	$12	$113
2015	$30	$10	$167	$64	$13	$106	$127	$25	$191	$77	$13	$115
2014	$30	$12	$191	$61	$14	$98	$117	$26	$176	$80	$16	$109
2013	$35	$12	$190	$56	$13	$95	$109	$25	$170	$66	$13	$102
2012	$33	$12	$180	$51	$11	$92	$103	$24	$166	$62	$13	$100
2011	$36	$13	$202	$47	$11	$84	$98	$23	$164	$61	$12	$101
2010	$36	$13	$211	$43	$11	$80	$97	$21	$170	$57	$11	$100
Mean	$31	$11	$178	$61	$13	$100	$119	$25	$181	$72	$13	$108

Notes: All dollar values are real, reported in $2018s. As defined in Figure 1, CI is consumer incidence, PI is producer incidence, and subsidy is the implicit fuel subsidy.

Table S8: Coal company production, subsidy benefit, and net income for 2018

Company	Domestic Production (1000 tons)	Benefit Low (M $s)	Benefit High (M $s)	Benefit Average (M $s)	Net Income (1000 $s)
Alliance Resource Partners LP	40,343	$347	$463	$405	$366,604
Arch Coal Inc	100,254	$863	$1,151	$1,007	$312,577
Blackhawk Mining LLC	13,317	$115	$153	$134	
Cloud Peak Energy	49,533	$427	$569	$498	-$718,000
CONSOL Energy Inc	27,592	$238	$317	$277	$178,785
Contura Energy Inc	22,811	$196	$262	$229	$302,854
Coronado Coal LLC	8,538	$74	$98	$86	$114,681
Foresight Energy Labor LLC	23,296	$201	$268	$234	-$61,613
Global Mining Group LLC	7,566	$65	$87	$76	
Hallador Energy Company	7,609	$66	$87	$76	$7,621
J Clifford Forrest	5,195	$45	$60	$52	
Kiewit Peter Sons' Inc	18,516	$159	$213	$186	
Murray Energy Corp	46,402	$400	$533	$466	
NACCO Industries Inc	37,282	$321	$428	$375	$34,785
Peabody Energy Corp	155,523	$1,339	$1,786	$1,563	$544,400
Prairie State Energy Campus	6,332	$55	$73	$64	
Revelation Energy LLC/Blackjewel LLC	38,521	$332	$442	$387	
Vistra Energy	13,982	$120	$161	$140	
Warrior Met Coal Intermediate Holdco LLC	7,735	$67	$89	$78	$696,787
Western Fuels Assoc Inc	6,304	$54	$72	$63	
Westmoreland Mining Holdings LLC	14,846	$128	$170	$149	
White Stallion Energy	5,576	$48	$64	$56	
Wolverine Fuels LLC	9,057	$78	$104	$91	
All others	90,037	$775	$1,034	$905	
TOTAL	756,167	$6,512	$8,683	$7,598	

Notes: The "All others" category accounts for reported domestic production not associated with a company name. Benefit low and high scenarios correspond to assumptions $I_U^P = .75$ and $I_U^P = 1$, respectively. The benefit average scenario is the average of low and high. All dollar values are reported in $2018s.

Table S9: Coal company production, subsidy benefit, and net income for 2017

Company	Domestic Production (1000 tons)	Benefit Low (M $s)	Benefit High (M $s)	Benefit Average (M $s)	Net Income (1000 $s)
Alliance Resource Partners LP	37,809	$324	$432	$378	$303,638
Arch Coal Inc	100,298	$859	$1,145	$1,002	$238,450
Blackhawk Mining LLC	13,088	$112	$149	$131	
Cloud Peak Energy	57,623	$493	$658	$575	-$6,600
CONSOL Energy Inc	26,109	$223	$298	$261	$82,569
Contura Energy Inc	10,449	$89	$119	$104	$173,735
Coronado Coal LLC	8,668	$74	$99	$87	$142,283
Foresight Energy Labor LLC	21,108	$181	$241	$211	-$215,233
Global Mining Group LLC	5,884	$50	$67	$59	
Hallador Energy Company	6,612	$57	$75	$66	$33,076
J Clifford Forrest					
Kiewit Peter Sons' Inc	19,581	$168	$223	$196	
Murray Energy Corp	45,869	$393	$524	$458	
NACCO Industries Inc	37,172	$318	$424	$371	$30,337
Peabody Energy Corp	156,728	$1,342	$1,789	$1,565	
Prairie State Energy Campus	6,202	$53	$71	$62	
Revelation Energy LLC/Blackjewel LLC	37,247	$319	$425	$372	
Vistra Energy	24,803	$212	$283	$248	-$254,000
Warrior Met Coal Intermediate Holdco LLC	6,714	$57	$77	$67	$455,046
Western Fuels Assoc Inc	6,046	$52	$69	$60	
Westmoreland Mining Holdings LLC	25,053	$214	$286	$250	
White Stallion Energy					
Wolverine Fuels LLC					
All others	121,546	$1,040	$1,387	$1,214	
TOTAL	774,609	$6,631	$8,841	$7,677	

Notes: The "All others" category accounts for reported domestic production not associated with a company name. Benefit low and high scenarios correspond to assumptions $I_U^P = .75$ and $I_U^P = 1$, respectively. The benefit average scenario is the average of low and high. All dollar values are reported in $2017s.

Table S10: Natural gas and oil (i.e., gasoline and diesel) company production, subsidy benefit, and net income for 2018 (in millions of dollars)

	Natural gas			Gasoline & Diesel			Combined	
Company	Domestic Production (bcf)	Benefit Low	Benefit High	Domestic Oil Production (M barrels)	Benefit low	Benefit high	Benefit average	Net income
Anadarko Petroleum Corporation	390	$164	$219	143	$88	$133	$302	$1,962
Antero Resources Corporation	711	$299	$398	46	$28	$43	$384	$509
Apache Corporation	217	$91	$122	59	$36	$55	$152	$315
BHP Billiton Group	271	$114	$152	58	$36	$54	$178	-$1,446
BP*	751	$316	$421	162	$150	$200	$544	$2,398
Brazos Valley Longhorn, L.L.C.	22	$9	$12	15	$9	$14	$22	$138
Cabot Oil & Gas Corporation	730	$307	$409	1	$1	$1	$359	$611
California Resources Corporation	73	$31	$41	36	$22	$33	$64	$550
Carrizo Oil & Gas, Inc.	25	$11	$14	18	$11	$17	$26	$443
Chesapeake Energy Corporation	832	$350	$466	52	$32	$48	$448	$1,496
Chevron Corporation*	377	$158	$211	224	$208	$277	$427	$3,452
Cimarex Energy Co.	206	$87	$115	47	$29	$44	$137	$863
CNX Resources Corporation	468	$197	$262	6	$4	$6	$234	$421
Comstock Resources, Inc.	100	$42	$56	2	$1	$2	$51	$132
Concho Resources Inc.	208	$87	$117	61	$38	$57	$149	$827
ConocoPhillips	308	$129	$173	171	$106	$159	$283	$3,668
Continental Resources, Inc.	285	$120	$160	61	$38	$57	$187	$1,337
Denbury Resources Inc.	4	$2	$2	21	$13	$19	$18	$470
Devon Energy Corporation	397	$167	$223	86	$53	$80	$261	$1,538
Diamondback Energy, Inc.	35	$15	$20	42	$26	$39	$50	$928
Encana Corporation	55	$23	$31	43	$27	$40	$60	$693
EOG Resources, Inc.	351	$148	$197	187	$116	$173	$317	$3,766
EP Energy Corporation	45	$19	$25	22	$14	$20	$39	-$558
EQT Corporation	1,393	$586	$781	17	$11	$16	$696	-$1,309
Extraction Oil & Gas, Inc.	47	$20	$26	20	$12	$19	$39	$280

Table S10: Continued.

Company	Natural gas Domestic Production (bcf)	Natural gas Benefit Low	Natural gas Benefit High	Gasoline & Diesel Domestic Oil Production (M barrels)	Gasoline & Diesel Benefit low	Gasoline & Diesel Benefit high	Combined Benefit average	Combined Net income
Exxon Mobil Corporation*	1,042	$438	$584	164	$152	$203	$688	$1,124
Gulfport Energy Corporation	444	$187	$249	9	$6	$8	$225	$463
Hess Corporation	75	$32	$42	57	$35	$53	$81	$48
Marathon Oil Corporation*	156	$66	$87	83	$77	$103	$166	$1,030
Montage Resources Corporation	90	$38	$50	6	$4	$6	$49	$112
Murphy Oil Corporation	17	$7	$10	21	$13	$19	$25	$244
National Fuel Gas Company	163	$69	$91	3	$2	$3	$82	$183
Noble Energy, Inc.	172	$72	$96	65	$40	$60	$135	$299
Oasis Petroleum Inc.	42	$18	$24	23	$14	$21	$38	$99
Occidental Petroleum Corporation	119	$50	$67	116	$72	$108	$148	$696
Parsley Energy, Inc.	37	$16	$21	34	$21	$32	$44	$695
PDC Energy, Inc.	88	$37	$49	25	$15	$23	$62	$71
Pioneer Natural Resources Co.	157	$66	$88	93	$57	$86	$149	$716
QEP Resources, Inc.	140	$59	$78	29	$18	$27	$91	-$741
Range Resources Corporation	548	$230	$307	43	$27	$40	$302	$228
Riviera Resources, Inc.	90	$38	$50	5	$3	$5	$48	$343
Roan Resources, Inc.	42	$18	$24	9	$6	$8	$28	$163
Royal Dutch Shell*	377	$158	$211	140	$130	$173	$336	$1,344
Sanchez Energy Corporation	55	$23	$31	20	$12	$19	$42	$393
SM Energy Company	103	$43	$58	27	$17	$25	$71	$528
Southwestern Energy Company	807	$339	$452	23	$14	$21	$414	$1,037
SRC Energy Inc.	37	$16	$21	12	$7	$11	$27	$296
Ultra Petroleum Corp.	260	$109	$146	2	$1	$2	$129	$389
Whiting Petroleum Corporation	47	$20	$26	39	$24	$36	$53	$552
WPX Energy, Inc.	64	$27	$36	38	$23	$35	$61	$330
TOTAL	13,473	$5,663	$7,551	2,686	$1,899	$2,729	$8,921	

Notes: The natural gas benefit low and high scenarios correspond to assumptions $I_U^P = .75$ and $I_U^P = 1$, respectively. The gasoline and diesel benefit low and high scenarios correspond to assumptions $I_U^P = .5$ and $I_U^P = .75$, respectively, with the exception of that for the 5 vertically integrated companies with an asterisk, in which case the assumptions are $I_U^P = .75$ and $I_U^P = 1$. The combined benefit average scenario is the average of all 4 scenarios. All dollar values are reported in millions of $2018s.

Table S11: Natural gas and oil (i.e., gasoline and diesel) company production, subsidy benefit, and net income for 2017 (in millions of dollars)

	Natural gas			Gasoline & Diesel			Combined	
Company	Domestic Production (bcf)	Benefit Low	Benefit High	Domestic Oil Production (M barrels)	Benefit low	Benefit high	Benefit average	Net income
Anadarko Petroleum Corporation	461	$182	$243	131	$73	$109	$303	$95
Antero Resources Corporation	591	$234	$311	38	$21	$32	$299	$378
Apache Corporation	144	$57	$76	51	$28	$42	$102	$84
BHP Billiton Group	288	$114	$152	66	$37	$55	$179	-$520
BP*	664	$262	$350	155	$129	$172	$457	$3,062
Brazos Valley Longhorn, L.L.C.							$0	
Cabot Oil & Gas Corporation	655	$259	$345	5	$3	$4	$306	$352
California Resources Corporation	66	$26	$35	36	$20	$30	$55	$238
Carrizo Oil & Gas, Inc.	28	$11	$15	15	$8	$12	$23	$307
Chesapeake Energy Corporation	878	$347	$463	54	$30	$45	$442	$1,182
Chevron Corporation*	354	$140	$187	190	$158	$211	$348	$280
Cimarex Energy Co.	187	$74	$99	38	$21	$32	$113	$541
CNX Resources Corporation	365	$144	$192	7	$4	$6	$173	$583
Comstock Resources, Inc.								
Concho Resources Inc.	161	$64	$85	43	$24	$36	$104	$920
ConocoPhillips	409	$162	$216	153	$85	$127	$295	-$1,106
Continental Resources, Inc.	228	$90	$120	51	$28	$42	$141	$1,054
Denbury Resources Inc.	4	$2	$2	21	$12	$17	$16	$163
Devon Energy Corporation	433	$171	$228	78	$43	$65	$254	$1,291
Diamondback Energy, Inc.	21	$8	$11	25	$14	$21	$27	$670
Encana Corporation	97	$38	$51	36	$20	$30	$70	$585
EOG Resources, Inc.	293	$116	$154	154	$86	$128	$242	$1,096
EP Energy Corporation	46	$18	$24	22	$12	$18	$36	$117
EQT Corporation	795	$314	$419	19	$11	$16	$380	$182
Extraction Oil & Gas, Inc.	32	$13	$17	13	$7	$11	$24	$57

Table S11: Continued.

	Natural gas			Gasoline & Diesel			Combined	
Company	Domestic Production (bcf)	Benefit Low	Benefit High	Domestic Oil Production (M barrels)	Benefit low	Benefit high	Benefit midpoint	Net income
Exxon Mobil Corporation*	1,181	$467	$622	152	$127	$169	$692	$6,027
Gulfport Energy Corporation	350	$138	$184	8	$4	$7	$167	$611
Hess Corporation	82	$32	$43	56	$31	$47	$77	-$2,762
Marathon Oil Corporation*	127	$50	$67	65	$54	$72	$122	-$148
Montage Resources Corporation								
Murphy Oil Corporation	16	$6	$8	20	$11	$17	$21	$3
National Fuel Gas Company	157	$62	$83	3	$2	$2	$74	$144
Noble Energy, Inc.	222	$88	$117	62	$34	$52	$145	-$1,512
Oasis Petroleum Inc.	32	$13	$17	19	$11	$16	$28	$112
Occidental Petroleum Corporation	108	$43	$57	93	$52	$77	$114	-$564
Parsley Energy, Inc.	23	$9	$12	21	$12	$17	$25	$398
PDC Energy, Inc.	72	$28	$38	20	$11	$17	$47	-$27
Pioneer Natural Resources Co.	143	$57	$75	78	$43	$65	$120	$1,464
QEP Resources, Inc.	169	$67	$89	25	$14	$21	$95	$28
Range Resources Corporation	491	$194	$259	40	$22	$33	$254	$514
Riviera Resources, Inc.								
Roan Resources, Inc.								
Royal Dutch Shell*	293	$116	$154	109	$91	$121	$241	-$1,212
Sanchez Energy Corporation	55	$22	$29	17	$9	$14	$37	$242
SM Energy Company	123	$49	$65	24	$13	$20	$73	$190
Southwestern Energy Company	797	$315	$420	17	$9	$14	$379	$755
SRC Energy Inc.								
Ultra Petroleum Corp.	260	$103	$137	3	$2	$2	$122	$270
Whiting Petroleum Corporation	41	$16	$22	36	$20	$30	$44	-$1,756
WPX Energy, Inc.	76	$30	$40	27	$15	$22	$54	$367
TOTAL	12,018	$4,750	$6,333	2,296	$1,461	$2,099	$7,322	

Notes: The natural gas benefit low and high scenarios correspond to assumptions $I_U^P = .75$ and $I_U^P = 1$, respectively. The gasoline and diesel benefit low and high scenarios correspond to assumptions $I_U^P = .5$ and $I_U^P = .75$, respectively, with the exception of that for the 5 vertically integrated companies with an asterisk, in which case the assumptions are $I_U^P = .75$ and $I_U^P = 1$. The combined benefit average scenario is the average of all 4 scenarios. All dollar values are reported in millions of $2017s.