Note

August 6, 2024 Coly Elhai

1 Project proposal

Emissions in Space: The Case of Manufacturing

- **Purpose:** Quantify differences in the carbon intensity of manufacturing across space. Determine the elasticity of energy demand with respect to prices, including the substitutability of different energy inputs. Analyze the economic and climate impacts of various policies affecting industrial energy consumption via 1) firm location subsidies, 2) electricity transmission infrastructure, and 3) general transport infrastructure.
- **Motivation:** Many policies (place-based industrial policy, local subsidies, transport infrastructure) influence industrial location choices. These policies almost never consider the climate consequences of these impacts. Because industry consumes huge amounts of electricity, and because the carbon intensity of electricity varies tremendously across space, these climate consequences may be of first-order importance. Furthermore, given the challenges of building long-distance electricity transmission infrastructure, it may be worthwhile to consider alternate policies affecting the geography of energy demand rather than of energy supply.
- **Approach:** Use plant-level data on energy use, energy type, and production in the U.S. (Manufacturing Energy Consumption Survey + Economic Census). First, establish patterns in the carbon intensity of manufacturing activity across space. In which places is production most polluting, and to what extent is heterogeneity across space mediated by the carbon intensity of the electric grid? Then, build a model of optimal firm location choice and energy input mix, accounting for input costs, trade costs, and agglomeration. Estimate parameters using variation in natural gas prices over time and space induced by the fracking revolution. Examine production and emissions under counterfactuals (changes in trade costs, changes in energy costs, place-based subsidies).
- **Contribution:** This project will demonstrate the importance of an as-yet unstudied mechanism in climate change policy: the impact of industry location on the carbon intensity of production. I will explore the scale to which this mechanism affects the social welfare gains/losses from building more transmission, building other transport infrastructure, or using place-based subsidies.

Questions:

- How much spatial heterogeneity was there in natural gas prices and availability around the time of the fracking revolution? Are differences significant and persistent enough to plausibly infuelnce investment decisions?
- Has there been any work on power plant fuel switching around the fracking revolution?
- Does this project sound interesting to you?

2 Methane modeling challenges

In the model for our project "Methane and Markets: Firm Incentives to Emit", every period the firm chooses $m_{it} \in [0, q_{it}]$, the quantity of gas extracted that it sends to market (i.e., sells). The remaining gas is flared or vented (at no cost). Firm i's profits in period t is given by

$$\max_{m_{it} \in [0, q_{it}]} p_t m_{it} - c_i(m_{it}; r_t, q_{it}),$$

where $c_i(m_{it}; r_t, q_{it})$ is the marketing cost. This function $c(\cdot)$ captures all costs related to selling the gas (processing the gas, transporting it to market via pipelines, etc.). We assume the firms are price-takers and equate marginal revenue to marginal cost, so marginal cost is identified from prices.

We've tried many different ways of parameterizing marketing costs $c_i()$ so that we can estimate it using a regression with gas prices and transmission costs.[1] Every parameterization we've tried yields bizarre results when we try to

[1] For instance, we've assumed forms such as $c_i(m_{it}; r_t, q_{it}) = \frac{\gamma_{0i}}{\gamma_2+1} r_t^{\gamma_1} m_{it}^{\gamma_2+1} q_{it}^{\gamma_3} \exp(\eta_{it})$ where γ_{0i} is a firm-specific cost multiplier, γ_1 captures sensitivity to the spot market for transmission, γ_2 captures the convexity of marketing costs, and γ_3 captures dispersion in costs related to production levels. This yields an FOC of $\log p_t = \log \gamma_{0i} + \gamma_1 \log r_t + \gamma_2 \log m_{it} + \gamma_3 \log q_{it} + \eta_{it}$

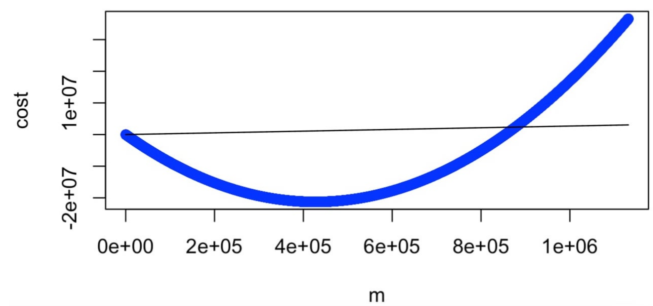
match it to producer-month level data. We want a parameterization that is convex (to capture higher costs of marketing gas outside of firm contracts), but not so convex that earlier units are costless to market. We also want convexity to be increasing in transmission costs. Many functional forms that we estimate yield non-convex costs, extremely negative costs, or other implausible results (see for example Figure 1).

It seems our issue is either noise or factors observable to producers that we can't capture: without firm fixed effects, our R^2 when estimating marketed gas shares generally falls below 0.05. This is true even though on aggregate, price variables correlate with marketed gas shares (Figures 2, 3). We need a cost function to plug it into the firm dynamic optimization problem for well drilling (see Appendix section 3.1), which will then allow us to model counterfactuals.

Questions:

- Does it make sense intuitively that the marketed gas volume decision is very noisy?
- If we continue to be unable to find a reasonable cost function, what options do we have for completing this paper?

Figure 1: Estimated cost-curve for one parameterization



Notes: In blue is one of the many cost-curves generated in our efforts to parameterize. The black line represents revenues, assuming a constant gas price of \$2.50. m is the marketed volume of gas. Note the extreme negative cost values and decreasing costs over the first portion of the domain.

3 Appendix

3.1 Dynamic model of well drilling

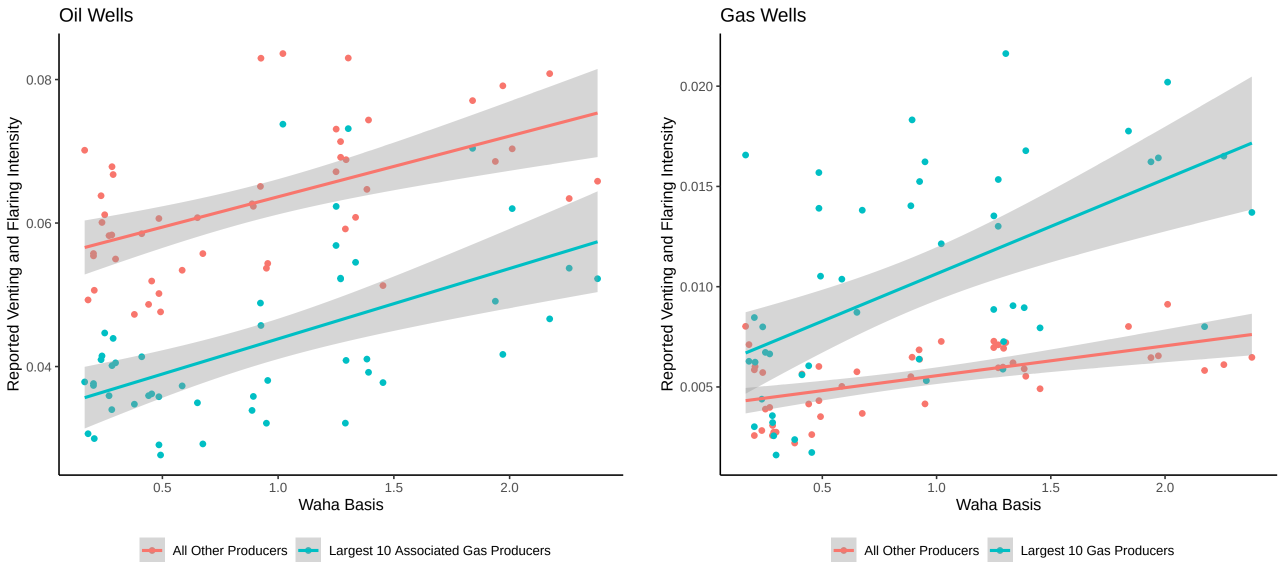
Firms choose the number of wells to drill in each period, $a_{it} \in A = \{0, 1, ..., J\}$, to maximize the stream of future-discounted expected profits. Wells drilled in period t begin producing in period $t+1$. Drilling costs c_t are a function of number of wells drilled and are allowed to vary by period. The firm's dynamic optimization problem is given by

$$V(\Omega_{it}, \varepsilon_{it}) = \max_{a} \bar{\pi}_i(\Omega_{it}) - c(\Omega_{it}, a) \; - \tau f a + \varepsilon_{it}(a) + \beta \mathbb{E}[V(\Omega_{it+1}, \varepsilon_{it+1})|\Omega_{it}, \varepsilon_{it}, a] \tag{1}$$

where β is the discount rate, f is the emissions associated with each drilling event, and $\varepsilon_{it}(a)$ is a profit shock which is assumed to be i.i.d. Type 1 Extreme Value with mean zero and scale parameter σ_ε. Profit shocks $\varepsilon_{it}(a)$ are independently distributed over time and across firms.

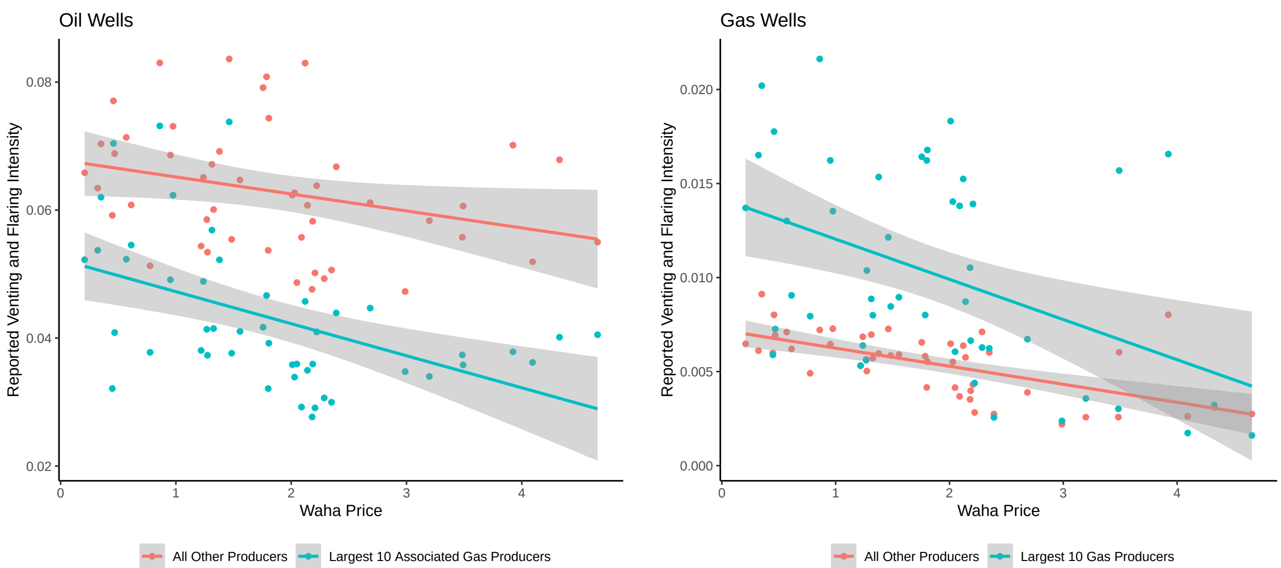
3.2 Methane figures

Figure 2: Producer-reported venting and flaring vs. Waha basis



Notes: Each observation is a lease-month. Data span January 2018 through January 2023. The sample includes all leases in the districts that the Texas Railroad Commission designates as belonging to the Permian Basin (7C, 8, and 8A). "Waha Basis" is the difference between Henry and Waha spot prices, averaged within month. We calculate reported venting and flaring intensity to be the ratio of vented/flared gas to total gas produced. For gas wells, the largest 10 producers are defined as the operators that accounted for the most gas produced during this period. For oil wells, the largest 10 producers are defined as the operators that accounted for the most casinghead gas (i.e., gas coming from oil wells) produced during this period.

Figure 3: Producer-reported venting and flaring vs. Waha prices



Notes: Each observation is a lease-month. Data span 2017 through 2024. The sample includes all leases in the districts that the Texas Railroad Commission designates as belonging to the Permian Basin (7C, 8, and 8A). "Waha Basis" is the difference between Henry and Waha spot prices, averaged within month. We calculate reported venting and flaring intensity to be the ratio of vented/flared gas to total gas produced. For gas wells, the largest 10 producers are defined as the operators that accounted for the most gas produced during this period. For oil wells, the largest 10 producers are defined as the operators that accounted for the most casinghead gas (i.e., gas coming from oil wells) produced during this period.

Table 1: Flared Gas, Prices, and Production

	Dependent variable:		
	log(Flared Volume (Tg/a))		
	All	Midland	Delaware
	(1)	(2)	(3)
Waha Hub Price	−0.030	0.107	−0.151*
	(0.074)	(0.097)	(0.076)
Henry - Waha Hub Price	0.298**	0.582***	0.138
	(0.114)	(0.147)	(0.120)
Cushing Spot Oil Price	0.0001	−0.0005	−0.001
	(0.007)	(0.008)	(0.006)
log(Oil Production)	3.080*	4.632***	0.815
	(1.787)	(1.495)	(2.293)
log(Gas Production)	−2.513*	−2.417**	−1.380
	(1.353)	(1.074)	(1.971)
log(New Wells)	0.017	−0.590*	0.240
	(0.275)	(0.315)	(0.215)
log(Lagged New Wells)	−0.042	0.093	0.088
	(0.243)	(0.292)	(0.221)
Constant	−4.869	−33.176***	12.630***
	(7.366)	(8.354)	(4.650)
Observations	46	46	46
R^2	0.657	0.663	0.666
Adjusted R^2	0.594	0.601	0.605
Residual Std. Error (df = 38)	0.263	0.359	0.272
F Statistic (df = 7; 38)	10.393***	10.678***	10.839***

Notes: An observation is a month. Outcome variable is the volume of flared gas, based on VIIRS observations and calibrated to match administrative data. Prices reflect the average of daily prices over the month, where daily prices are winsorized at the 1% level. Oil and gas production and new wells are measured monthly. Oil and gas production are in barrels and thousands of cubic feet (Mcf), respectively.
$^{*}p < 0.1, ^{**}p < 0.05, ^{***}p < 0.01$