A Physical Inventory of the U.S. Energy System

Supporting material for a manuscript in preparation for PNAS

Hsin-Yi Chen[1,2,*], David A. Weisbach[3,], Nathan J. Matteson[4,], Alison Brizius[1,5,], Elisabeth J. Moyer[1,6,**]

Abstract

Concerns over climate change and energy security have prompted calls to reduce or eliminate the use of fossil fuels in the United States. A major obstacle to large-scale transition of the energy sector is its capital intensiveness, the large fixed investment in long-lived infrastructure such as pipelines, refineriers, and power plants, much of which is exclusive to fossil fuels. Any transition requires replacing existing assets, and an overly rapid transition requires absorbing losses from premature retirement of "stranded assets". Insight into plausible timecales of energy transitions has to date been hindered by lack of a comprehensive accounting of energy-related assets. We meet this need here by constructing a physical inventory of energy infrastructure in the United States: a listing of all assets, as well as their upfront costs, typical service life, and age structure where available. We find that the collective replacement cost of long-lived assets in the U.S. energy system in the benchmark year of 2012 is ∼$9.8 T, two-thirds of which ($6.4 trillion) is exclusive to fossil fuels. This total is equivalent to ∼$30,000 per U.S. resident in replacement cost ($16,000 in depreciated value), or $3 per Watt of primary energy flow. The inventory offers multiple immediate insights. When compared with energy sector investment data, it is evident that recent increases in renewables investment remain small relative to investment in non-fossil assets. The energy sector also shown no trend to reduced dependence on infrastructure; instead the capital intensiveness of the U.S. energy sector has risen over time. The energy inventory provides a benchmark for realistic policy analyses, and demonstrates that the scale of energy infrastructure provides a significant constraint on the cost and timing of energy transitions.

Keywords: energy transition, infrastructure, stranded asset

*Corresponding author

**Corresponding author

Email address: moyer@uchicago.edu (Elisabeth J. Moyer)

[1]The Center for Robust Decision-making on Climate and Energy Policy, University of Chicago

[2]Department of Electrical Engineering, University of Hawaii

[3]Law School, University of Chicago

[4]College of Computing and Digital Media, DePaul University

[5]*now at:* Climate and Environmental Planning, Environment Department, City of Boston

[6]Department of the Geophysical Sciences, University of Chicago

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A. Overview and summary of results

This document summarizes our physical inventory of of long-lived U.S. energy sector assets and their upfront costs. Wherever possible, we count individual assets and estimate a cost per unit. In some cases we book-keep the total "capacity" of an asset class (e.g. potential barrels of oil per day refined), and estimate a cost per unit capacity. Since our purpose is to estimate a replacement cost, we base all estimates not on historical costs at the time of construction, but on newbuild costs around the year 2012.[7] All costs are given in 2012 dollars, unless noted otherwise. Table 1 below summarizes the final estimates, which total **$9.8 T** for all U.S. long-lived energy infrastructure, of which **$6.4 T** is exclusive to fossil fuels. The total capital intensiveness of the U.S. energy sector is $3.3 per W of primary energy flow ($1.6/W depreciated), or, since each U.S. resident uses ∼10,000 W primary power, $33,000 per capita in upfront cost ($16,000 depreciated).

		Book value ($B)	Asset lifespan (years)
Extraction	Oil and gas wells, domestic	1,713	20
	Oil wells, foreign	931	20
	Gas wells, foreign (Canada)	63	20
	Coal mines	57	40
Processing	Oil refineries	373	60
	Natural gas processing plants	48	35
Transportation	Oil pipelines	170	60
	Gas pipelines (gathering, transmission)	446	60
	Gas pipelines (distribution, service)	494	60
	Canada-U.S. oil & gas transmission pipelines	14	60
	Oil tankers	18	30
	Oil rail cars	6	35
	Gas carriers	1	30
	LNG import terminals	19	40
	Coal rail	131	50
Storage	Oil storage	126	30
	Gas storage	55	50
Usage	Gasoline stations	96	20
	Power plants (coal, natural gas, petroleum)	1,645	30–50
	Power plants (nuclear, hydro)	*937*	*60*
	Power plants (solar, wind, geo, bio)	*219*	*25*
	Electricity T&D lines	*1,810*	*50*
	Electricity T&D substations	*391*	*40*
	Total	9,767	

Table 1: Estimated replacement costs of all long-lived U.S. energy assets, for the benchmark year of 2012, and their estimated service life. Assets exclusive to fossil fuels are in plain text, and sum to $6.41 T. "T&D" = "transmission and distribution."

The remainder of this section gives primary sources and describes the energy flows to which costs are often benchmarked (Table 2). Sections B–F discuss cost estimates for individual asset classes in detail, and Section J uses BEA data to estimate a depreciated value for all domestic energy sector assets ($4.5 T) and for those related to fossil fuels ($3.2 T)[8]. Section K determines the age structure of assets in the inventory where possible, and compares their depreciated values with analogous BEA categories. Section L evaluates data on energy investment and constructs a timeseries of the growth of U.S. energy infrastructure. Section M details the service lifetimes for each asset type, and Section N restates costs for each asset class in terms of $ per energy flow and $ per unit energy, allowing us to compare capital costs with fuel prices.

[7] One exception is that we seek to avoid the market distortions that occurred at the onset of the shale revolution, when competition for labor and materials temporarily drove up costs for some asset classes, especially wells and pipelines. These effects peaked around 2012. For affected assets, we choose values more representative of long-term average costs.

[8] Later adjusted in Section L to $4.2 T for the whole energy sector and $2.9 for the fossil-exclusive part.

A.1. Sources

While the physical inventory draws from hundreds of sources, we summarize below selected major sources from which we draw information:

- Oil and gas extraction: *Well count and type* from the 2018 release of the DrillingInfo database [1] and Bureau of Offshore Energy Management (BOEM) data [2]. *Costs* ($/well) from various sources but validated against IPAA and API-JAS reports. *Relative costs of foreign oil extraction* from Rystad [3]
- Pipelines: *Mileage and diameter* from the Dept. of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) database [4–6]. *Costs* ($/inch-mile) from reports on pipeline projects made to the Federal Energy Regulatory Commission (FERC) and compiled by the EIA [7]
- Power plants: *Count and capacity* (in kW) from the *EIA-860* survey [8]. *Costs* ($/kW capacity) primarily from the 2013 EIA assessment of overnight construction cost for power plants (*"Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants 2013"*, [9]), but also using an EIA survey of the construction cost of new electric generators installed in 2013–2015 [10–12], compiled as part of the *EIA-860* survey, and the 2014 *"Capital Cost Review of Power Generation Technologies"* [13], prepared by Energy and Environmental Economics, Inc. (E3) for the Western Electric Coordinating Council.
- Processing: *processing capacity* (bpd for refineries and bcfd for gas processing plants) from EIA data series [14, 15]. Costs from collected sources.
- Oil tankers: *global capacity* (deadweight ton, DWT) and *cost* ($/DWT) from Clarkson Research [16].
- Storage: *oil storage capacity* (bbl) from the 2013 EIA report *"Working and Net Available Shell Storage Capacity"* [17] and *gas storage capacity* (bcf) from EIA data series on natural gas storage [18]. Costs from collected sources.
- Coal mines: *production capacity* (in short tons per year, tpy) from the EIA 2012 Annual Coal Report and the Mine Safety and Health Administration [19, 20]. *Costs* ($/tpy) from the InfoMine *"2010 Coal Cost Guide"* [21].
- Coal railroads: *annual capital expenditure and coal share* (% of ton-mile) from the American Association of Railroads [22, 23].
- Transmission and Distribution: *Line mileage (circuit miles)* from summaries of the North American Electric Reliability Corporation's "Transmission Availability Data System" (NERC TADS) [24, 25] and from the Platts 2015 UDI Directory of Electric Power Producers and Distributors [26]. *Substation count* deduced from Dept. of Homeland Security "Homeland Infrastructure Foundation-Level Data" (HIFLD) [27]. *Costs* for transmission lines ($/circuit mile) from the Black & Veatch report *Capital Costs For Transmission and Substations* [28] and the National Council on Electricity Policy's *10-Year Transmission Assessment in 2003* [29], and for distribution lines ($/line mile) from analyses by the National Rural Electric Cooperative Association (NRECA) [30, 31]. *Substation costs* from Black & Veatch's *Generation & Transmission Model Methodology & Assumptions* [32] and collected project costs.

A.2. Energy flows

We use estimates of flows of energy in the U.S. energy system for multiple purposes: to determine costs of U.S. infrastructure (and foreign infrastructure that serves the U.S. market), to evaluate infrastrcture costs per unit energy or per energy flow, and to construct export adjustments for cases where not all U.S. infrastructure is used for domestic consumption. Tables 2 and 3 below show flows for oil, gas, and coal based primarily on EIA flow charts for 2012 [33–35]. These tables are used to derive several scaling and adjustment factors in this work, that correct for the fact that the U.S. is in 2012 a net importer of both natural gas and crude oil (6.3% and 130% of domestic production, respectively), and a net exporter of coal (11% of domestic production) and refined products.

Oil	Crude	M bpd Refined	Both	Source
consumption		18.5	18.5	[36]
prod (oil)	6.50		**6.50**	[36]
prod (NGL)		2.41	**2.41**	[36]
prod (renewable)		0.96	**0.96**	[36]
gross import	8.53	2.07	**10.60**	[36]
gross export	−0.07	−3.14	**−3.21**	[36]
net imp, crude	8.46			[d]
net exp, products		−1.07		[d]
gross imp, Canada	2.43	0.52	2.95	[37]
gross exp, Canada	−0.07	−0.35	−0.42	[38]
net sender flow	8.41	0.27	8.68	[37]
net receiver flow	0.05	−1.33	−1.29	[38]
processing gain		1.06	**1.06**	[36]
stock change & adj.			**0.15**	[36]

Natural gas	TCF/yr	Source
consumption	25.5	[36]
gross withdrawal	*29.5*	[36]
production (wet)	*25.3*	[36]
production (dry)	**24.0**	[36]
gross import	**3.14**	[39]
gross export	**−1.62**	[40]
net import	1.52	[d]
no net export		[d]
gross imp, Canada	2.96	[39]
gross exp, Canada	−0.97	[40]
net imp, Canada	1.99	[40]
LNG imp	0.17	[40]
LNG exp	−0.03	[40]
stock change & oth.	**−0.01**	[36]

Table 2: U.S. flows of oil (left) and gas (right) in 2012, used throughout this work, in units of barrels per day (bpd) and trillion cubic feet per year, respectively. Most are taken from EIA Annual Energy Review national aggregated series [36]: we use Table 3.1 for oil Table 4.1 for gas. Specific statistics for Import/export (including country-specific values) are taken from EIA data series. [d] denotes a derived result from other flows. Bold entries should add to total consumption, within rounding error. Unbolded entries are included for reference. Negative values denote export. *Gas:* For reference we show (italics) flows of extracted gas before processing. Total withdrawals at the wellhead are a combination of natural gas, contaminants, and hydrocarbon gases (natural gas liquids or NGL); "wet" natural gas contains NGL but has contaminants removed. Net import is $1.52/24 = 6.3\%$ of domestic production. *Oil:* The EIA reports consumption as "Product supplied", and groups oil together with both NGL and renewable liquid fuels (largely ethanol). We list these here as refined products. "Processing gain" is the volume difference between refined petroleum products and the crude oil from which they are defined, and for 2012 was ∼7% of the volume of processed crude oil (1.06 M out of 15.37 M bpd input, giving $1.06/15.37 = 7\%$ [36, Table 3.1][41]). Net imports of crude are $8.46/6.6 = 130\%$ of domestic production, but some imported crude is re-exported as refined products. We denote as "net senders" ("net receivers") those countries whose combined crude oil and refined product trade with the US is net positive (negative). See Fig 10 for breakout of sender and receiver countries. In both oil and gas tables we list Canada separately because it plays a unique role as the only country from which we import by pipeline. Canada is also the only destination for exported U.S. crude oil in 2012 (other than a negligible amount to Mexico).

Coal	M short ton/yr	Source
consumption	889	[36]
prod	**1,016**	[36]
prod. adj. (waste coal)	**11**	[36]
gross import	**9.2**	[36]
Colombia	7.0	[42–46]
Canada	1.7	[42–46]
gross export	**−125.7**	[36]
Europe	−61	[42–46]
Asia	−32.4	[42–46]
S.& C. America	−14.9	[42–46]
Canada	−7.2	[42–46]
net export	*−116.5*	[d]
stock change & losses	**−21.88**	[36]

Table 3: U.S. flow of coal in 2012, used throughout this work, data mostly from EIA Annual Energy Review national aggregated series found in Table 6.1 [36] and import/export (including country specific values) from EIA Quarterly Coal Reports in 2012 and other import/export data series. Format as in Table 2. Coal usage in the U.S. is largely domestic, with imports equivalent to ∼1% of domestic production. Net exports of $117/1016 = 11\%$ of domestic production are sent primarily to Europe and Asia. The small amount of imported coal is used only in power plants near ports (on the Gulf Coast and Atlantic Ocean) and distant from U.S. coal-producing regions. The primary source countries are Colombia and Canada, with remaining imports distributed across more than 13 countries [47]. (Note that Canada is a net importer of U.S. coal.)

We compute scaling factors to account for that foreign infrastructure the provides U.S. imports of natural gas and oil, and to remove from the inventory some U.S. infrastructure that serves the foreign market for exported refined products and coal. Net import of *natural gas* from Canada is 8% of domestic production, but this is offset by a 2% net export from the U.S. to other countries, mainly to Mexico. To estimate the infrastructure costs associated with extraction and processing of foreign natural gas, we simply take 6.3% of U.S. asset value. Estimating infrastructure costs for *foreign oil* is more involved, since capital costs vary by country and some accounting must be made for the export of refined products. We compute an asset value associated with the 8.7B bpd of net imports from "sender" countries by multiplying each country's net imports by its local capital cost per production. We then adjust that total by a factor (1 - 1.3/8.7) = 0.85 to account for residual net exports to "receiver" countries of 1.3B bpd (Section C.1). We adjust U.S. *coal* assets by a factor of 0.89 to account for net exports, and *refinery* assets by a factor of 0.93 to account for export of refined products (Section E.1).

A.3. Summary figures

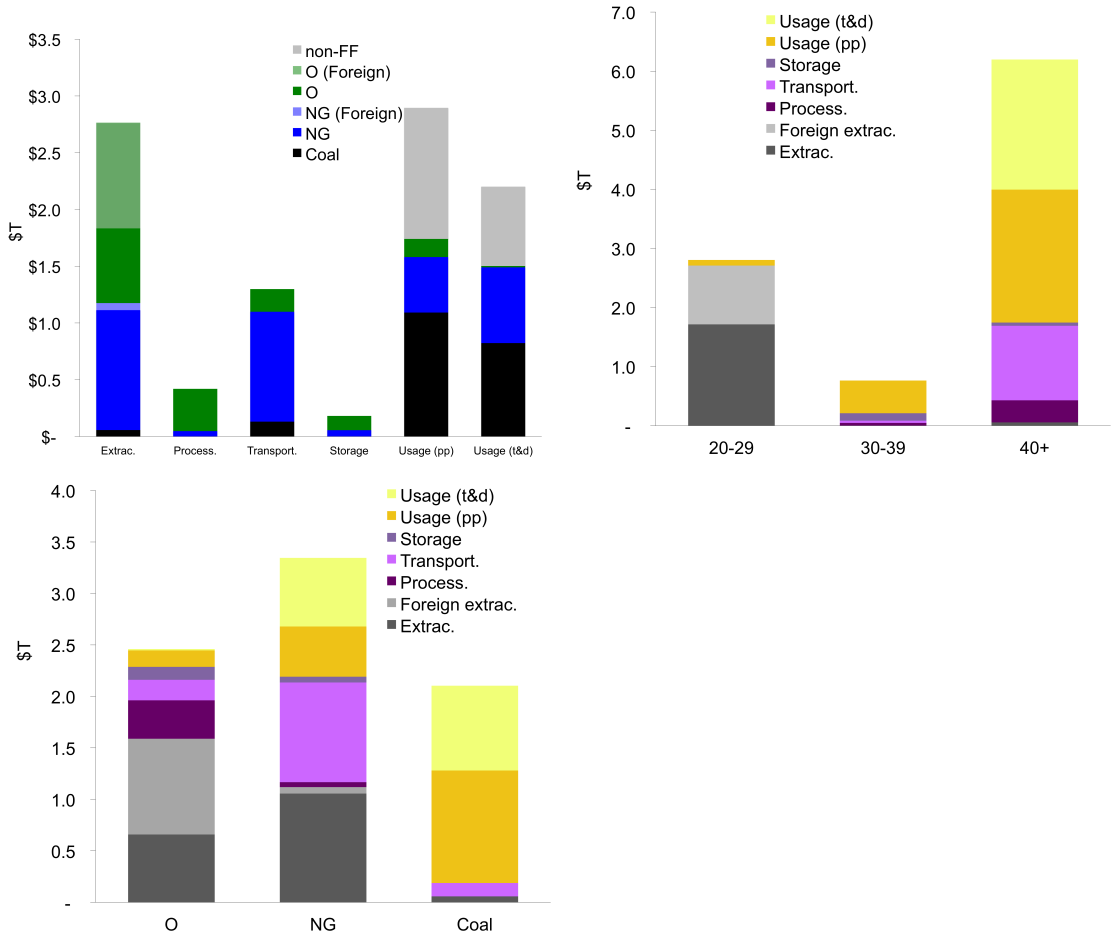

Figure 1: The distribution of total infrastructure value by fuel, service life, and supply chain activity. **Top left:** *by fuel.* The three major fossil fuels show very different infrastructure profiles. Oil assets are concentrated in extraction (upstream), coal in electricity generation (downstream), and natural gas throughout the supply chain. **Top right:** *by service life.* Most infrastructure in the energy system is very long-lived, with oil and gas extraction the main exception. For actual age structure, see Section K. **Bottom:** *by activity.* Electricity generation and transport is the largest part of the energy system, followed by oil and gas extraction. Transportation is significant for natural gas. Coal assets are concentrated in downstream sectors.

A.4. Abbreviations used in this work

ACES	Annual Capital Expenditure Survey, an annual survey on U.S. structure and equipment spending conducted by the Census Bureau
API	American Petroleum Institute
bbl	barrel, a standard reporting measure for oil
bcfd	billion cubic feet per day, a measure of natural gas production or usage
BEA	Bureau of Economic Analysis (part of the U.S. Dept. of Commerce)
boe	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management (part of the U.S. Dept. of the Interior)
bpd	barrels per day, a measure of oil production or usage
BTU	British thermal unit, a measure of energy equaling 1055 Joules
cbm	cubic meter, a measure of natural gas volume, usually for liquid natural gas
DOE	the U.S. Department of Energy
EEI	Edison Electric Institute, the association that represents all U.S. investor-owned electric companies
EIA	Energy Information Administration (part of the U.S. Dept. of Energy)
FAA	Fixed Asset Accounts, a U.S. assets investment inventory by the BEA
FDC	finding and development cost, a standard measure of the cost of oil or gas extraction per boe
FERC	Federal Energy Regulatory Commission, an independent agency that regulates interstate transmission of natural gas, oil, and electricity
GOR	gas-to-oil-ratio, a measure of relative well production, often given in units of MCF/BBL
ICF	ICF (*not an acronym*) is a consulting firm with expertise in energy
IEA	International Energy Agency, an organization of 30 member countries founded to manage oil supply
IGU	International Gas Union, a natural gas advocacy organization
IHS	Information Handling Services, a consulting firm with expertise in energy
INGAA	Interstate National Gas Association of America
IOU	an investor-owned utility
IPAA	Independent Petroleum Association of America
JAS	Joint Association Survey, an annual survey report on drilling activity conducted by the API
kWh	kilowatt hour, a measure of energy
LLNL	Lawrence Livermore National Laboratory (part of the U.S. Dept. of Energy)
LNG	liquified natural gas
mcf	thousand cubic feet, a standard reporting measure for natural gas
mcfd	thousand cubic feet per day, a measure of natural gas production or usage
mmcfd	million cubic feet per day, a measure of natural gas production or usage
MWh	megawatt hour, a measure of energy
NAICS	North American Industry Classification System, a standard used by Federal statistical agencies
NGL	natural gas liquids, hydrocarbons separated in gas processing, e.g. butane, propane, ethane
NIPA	National Income and Product Accounts, a product of the U.S. Dept. of Commerce
NMA	National Mining Association
PADD	Petroleum Administration for Defense District
PHMSA	Pipeline and Hazardous Material Safety Administration
quad	quadrillion (10^{15}) BTU, a measure of energy
tpy	short tons per year, a measure of coal mine production (1 short ton = 0.91 metric tons)
UICI	the Upstream Investment Cost Index, an adjustment for inflation and cost increases across countries
UNCTAD	United Nations Conference on Trade and Development
W	Watt, a measure of energy production or usage
$W_{cap.}$	Watts capacity, a measure of energy production capacity
WF	well and facility cost, a measure of capital expenditure for oil or gas extraction per boe

B. Domestic oil and gas wells

B.1. Summary

We estimate capital costs for domestic oil and gas extraction by constructing an inventory of all U.S. producing wells. We use the 2018 release of the DrillingInfo database [1] to derive number count and characteristics of onshore active wells, and Bureau of Ocean Energy Management (BOEM) data to tally active offshore wells [2, 48]. We sort the resulting set of active wells into 9 different classifications (7 onshore and 2 offshore) because well cost varies greatly depending on wellbore trajectory, well depth, and well completion methodology, e.g. hydraulic fracturing. Table 5 summarizes the results, and the remainder of this sections discusses in detail the classification of wells and the assignment of costs. The U.S. had around 1M active oil and gas wells in 2012 (32% oil and 58% gas), with a mean per-well cost of $1.65M. Most of these are simple conventional vertical wells. Hydraulically fracked horizontal wells make up only 7% of the total well count in 2012, but account for nearly a third of total costs The small subset of offshore wells, though individually expensive, contribute negligibly to total cost.

Class	Well Type	F	Baseline cost ($M)	Uncertainty ($M)	No. of wells	% total wells	% total cost	Avg yr online
1	Conventional vertical (excl. category 3)	x	1	0.8-2	588,602	57	34	1988
2	Unconventional horizontal	H	8	6.0-10	68,581	7	32	2007
3	Vertical in shale play; post 2003/2007 for gas/oil	L	1.5	1.1-2.7	112,037	11	10	2008
4	Directional (excl. category 5)	x	1.5	1.1-2.7	30,539	3	3	1998
5	Directional in shale play; post 2003/2007 for gas/oil	L	2.5	1.9-3.9	30,086	3	4	2009
6	Unknown direction (excl. category 7)	x	1	0.8-2	169,291	16	10	1989
7	Unknown dir. in shale play; post-2003/2007 for gas/oil	L	1.5	1.1-2.7	35,325	3	3	2007
8	Offshore shallow water	x	9	8.0-10	4,510	0.4	2	1995
9	Offshore deep water	x	50	30-200	485	0.05	1.4	2002
	Total well cost: **$1.7T**		1.6		1,039,456			

Table 5: Classification of the nearly 1M wells active in 2012 in our inventory into 9 categories for cost estimation. We use 7 categories for onshore wells (top) and 2 for offshore (bottom). Column labeled "F" indicates the use of modern hydraulic fracturing, either at high (H) cost for horizontal wells or at lower cost (L) for vertical/directional wells. Although three quarters of producing wells are not fracked, fracked wells are responsible for nearly half of estimated cost, with horizontal wells alone making up over 30% of costs.

B.2. Methodology and background

Assigning categories. Because no database contains the complete (and consistent) information required to estimate costs, we approximate total asset value by dividing wells into the broad categories shown above, each associated with a characteristic cost. Unfortunately well completion technology, including the use of hydraulic fracturing, is not explicitly specified in the DrillingInfo database, and must be inferred from well date, location, and wellbore trajectory. It is also important to note that even many relevant labels may be inconsistent even within the DrillingInfo database, because they are assigned by individual state agencies. We therefore rely primarily on production information rather than on state-assigned labels. Section B.3 below discusses in detail the determination of active wells and their assignment categories, and the validation of the resulting inventory.

Defining costs. Throughout this inventory, we estimate infrastructure costs as replacement cost in the baseline year of 2012. We also adopt the practice of making conservative (lower cost) assumptions, so that the final inventory cost represents a robust lower bound. For wells, this necessitates some judgement about the use of cost estimates from the beginning of the shale revolution, especially the 2008-2012 period, when rapid expansion of production created market distortions that temporarily drove up prices for labor and materials. Costs for unconventional wells also evolved rapidly during this period. We therefore exercise some caution with cost estimates from this period, and conservatively attempt to avoid short-term market effects. Because our baseline estimates are deliberately conservative, uncertainty ranges tend to be asymmetric.

For wells, we define the replacement cost as the "development cost" for wells that produce oil or gas, which includes drilling and stimulation (hydraulic fracturing) but not exploration or production, or the

drilling of 'dry' wells that were deemed to have production too low to justify completion. Exploration cost – drilling exploratory wells to assess whether the field is economic feasible for production – is relatively small and difficult to quantify, with limited informative data. Published estimates based on 2002-2012 data report exploration as adding roughly $\sim$ 7-30% to development costs[9] [49–51]. Production cost (the "lifting cost" to actually pump oil/gas out of the wells) is an operational expense rather than a capital investment and therefore not in the scope of this inventory.

Cost evolution over time. Mean per-well cost rose significantly with the introduction of modern hydraulic fracturing in the mid-2000s. Older wells are predominantly simple vertical wells drilled to reach an oil or gas reservoir. With the shale revolution, many wells become more complex, involving horizontal drilling – a vertical segment followed by a long lateral section of several thousand feet to tap a wider area of the reserve [e.g. 52, 53] – and well completion evolves from simple cleaning and casing to employing high-pressure hydraulic fracturing to stimulate the release of oil and gas. While some version of hydraulic fracturing for well stimulation has existed for decades [54, 55], the contemporary version uses a much higher volume of water mixed with proppant, sand, and other chemicals, and incurs higher expense. Fracking practices are still evolving to longer lateral lengths, more fracking stages, and higher volumes of fracking fluid [52, 56–58]. Unconventional horizontal wells now have costs nearly an order of magnitude above conventional vertical wells, with correspondingly higher production yields [e.g. 59, 60]. (That is, capital cost per unit of production has remained relatively constant even while per-well cost has increased markedly [61]). Our DrillingInfo-based inventory suggests that by 2012, 70% of new U.S. wells are hydraulically fracked, with over 35% being high-cost horizontal wells[10] (Figure 2; see Figure 3 for associated rise in per-well cost). But, because well lifetimes are long, horizontal fracked wells still comprise only 7% of the 2012 well fleet.

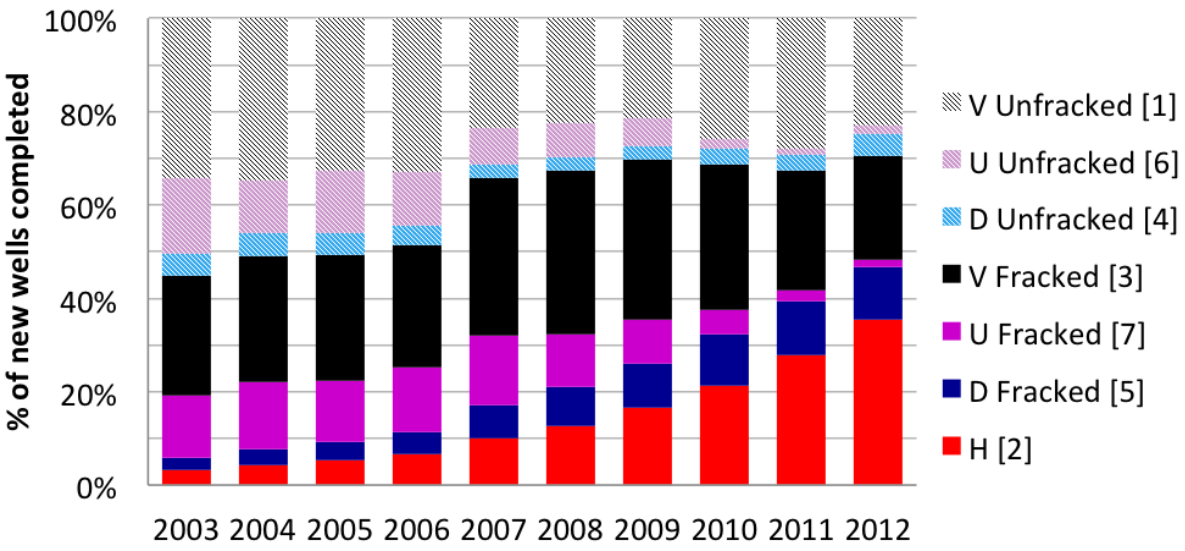

Figure 2: Annual new well completions broken down by the categories of Table 5. Source data: DrillingInfo 2018 [1]

Estimating well costs. Well costs are difficult to estimate for multiple reasons. Data on well cost and characteristics are closely guarded by oil and gas companies and considered proprietary and confidential [63–66]. Public-domain studies on well costs vary and provide little guidance on aggregate costs. Well costs have not only evolved over time but differ strongly across regions (because oil and gas plays are highly

[9]Reported exploration cost is \$1–\$6 per boe, while combined exploration / development cost is \$15–\$25 per boe [49–51]
[10]EIA concurs with this assessment; see [62]

variable in their characteristics) and within regions (according to the development technology chosen: the existence and length of horizontal segments drilled and the extent of fracking). Between-region differences mean that even vertical wells can vary widely in cost. U.S. shale formation depths range from 6,000 ft in in the Marcellus shale to 11,000 ft in the Permian Basin, and our collected data suggest that the cost difference could be a factor of three before horizontal drilling or hydraulic fracturing is even considered [53, 67]. The many studies that examine costs for individual wells or within a single formation therefore differ widely. (See Figure 4 and associated references.)

We ground our cost estimates for onshore well categories in Table 5 in literature cost estimates for the two well types that are widely discussed and analyzed: conventional vertical and horizontal hydraulically fracked [52, 68–70]. Our assumed costs for these categories are informed by a collection of more than 70 regional and national estimates drawn from formal and informal sources (Figure 4). We take a commonsense approach to selecting a conservative midrange value of these estimates, weighted to more reputable sources and to nationwide estimates. We also estimate costs for shallow and deep water offshore wells from literature estimates. For the the remaining 36% of total wells that do not fall into these four categories, there are few relevant reports documenting per-well costs. We therefore infer their costs by extrapolating from our vertical and horizontal assumptions, using simple scaling relationships to derive the additional incremental costs of drilling and fracking over a simple vertical well. We scale drilling costs by well depth, using the information from DrillingInfo [71], and fracking costs by fracking fluid volume from USGS [56–58]. (See discussion in following sections.)

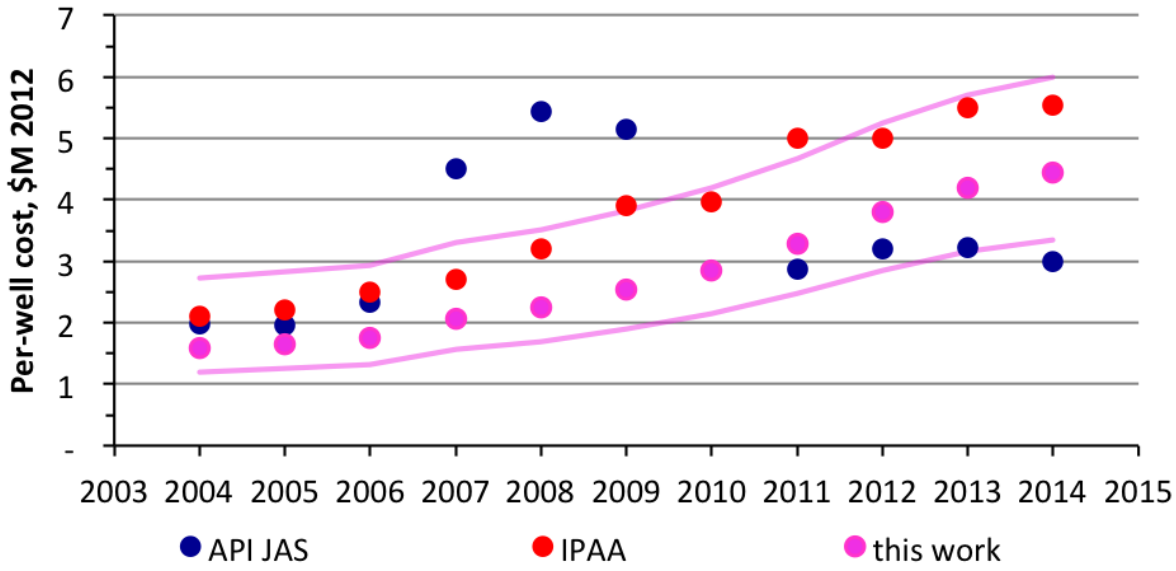

Figure 3: Comparison of aggregate annual cost for new wells in selected years from three sources: this inventory (pink), IPAA (red), and API JAS (blue). All costs are inflation-adjusted to 2012 dollars. Values for this work rise over time only because of changing proportions of different well categories: values are the replacement costs shown in Table 5 weighted by the annual new well count for each category. IPAA costs are constructed from reported historical capital expenditures divided by number of completions [72]. API JAS costs are quoted from different sources: 2004–2007, reported by the EIA [70]; 2008 and 2009, from an online excerpt of the executive summary of the 2009 JAS [73]; 2011 to 2015, derived based on annual well expenditure and new well count in various API press releases [74–76]). Both JAS and IPAA have some inconsistency with our inventory values: both include dry wells, which could raise or lower per-well costs slightly, and IPAA also includes exploration costs, which raise per-well costs.

Validating against other sources. To validate our cost assignments, we make use of two major large-scale assessments of average U.S. per-well cost for new completions each year. The American Petroleum Institute conducts an annual survey of oil and gas producers and describes results in their Joint Association Survey on Drilling Costs (JAS), and the Independent Petroleum Association of America (IPAA) releases annual summary statistics on wells drilled and total expenditure [e.g. 72]. We can construct a measure analogous to these cost estimates, i.e. a a timeseries of aggregate per-well costs, by combining our cost assignments for each well category with the Drillinginfo annual counts of new completions in each category. Comparing this derived quantity to JAS and IPAA values then provides an independent check on our cost assignments.

The resulting comparison suggests good agreement between our inventory-derived annual mean new well cost with costs from IPAA, and from JAS in the earliest years. Results for 2004–2014 are shown in Figure 3. IPAA per-well costs rise nearly monotonically over time and our estimates track them closely. As expected and intended, the estimates of this work are biased slightly lower than IPAA (by -23% on average), presumably because of our conservative assumptions and IPAA's inclusion of exploration costs. We take the agreement between this work and IPAA trends as a validation of our approach.

After 2006, annual values from JAS show considerable and implausible temporal variation. The JAS timeseries here is derived from a variety of secondary sources (see Figure 3 caption), but JAS well costs show large fluctuations even during time periods covered by a single source (e.g./ the jump between 2006 and 2007, when JAS costs are reported by the EIA.) Fluctuations may reflect changes in JAS survey pratices.

B.3. Classifying wells

1. Distinguishing offshore and onshore wells:

We inventory offshore wells separately, and characterize them using the more detailed 2017 database from the Bureau of Ocean Energy Management (BOEM) [2] rather than Drillinginfo. The BOEM manages energy and mineral responses on the federally controlled Outer Continental Shelf, which begins 3 nautical miles from shore at low tide.[11] Wells drilled in the shallower waters within this limit are state controlled, and inconsistently characterized in state databases. For simplicity, we consider as "offshore" only those wells on federal territory and therefore itemized by the BOEM. All wells on state territory are considered onshore. This choice may lead to a slight underestimation of costs, but the price premium for wells in the relatively shallow state waters should be low, and state offshore production is relatively small.[12] Nearly all oil and gas production from federal offshore wells in 2012 occurs in the Gulf of Mexico (96% for oil and 98% for gas [41, 78]), with the remainder almost entirely from Southern California.

We define active offshore wells in our inventory as those in the BOEM database with *Type Code* "Development" and *Status* "Borehole Completed". BOEM does not provide sufficient data to determine well activity in 2012, so the offshore inventory is effectively that for 2017. We use the common standard of 1000 ft water depth to distinguish deep from shallow water wells [e.g. 79–81]. Onshore wells are counted and classified from the DrillingInfo database, after first removing all those with "State" label 'FO GULF' (federal offshore well, Gulf of Mexico). (We confirm the accuracy of the FO GULF designation using Google Earth Engine [82] and BOEM Oil and Gas Planning Areas maps [83].) The process of categorizing onshore wells then involves three additional steps, detailed below.

2. Identifying active onshore wells: We identify active wells included in our physical inventory as all those with recorded first production date on or before 2012 and latest production date on or after 2012. We do not rely on information from the DrillingInfo "Well Producing Status" entry, which describes well status only at the time of the 2018 data release. To determine well timing we use the First Production Date / Last Production Date entries in Drillinginfo for consistency, rather than other measures related to

[11] Federal offshore territory is defined by the Submerged Lands Act of 1953, which includes three exceptions (larger state territories) for states with earlier historical offshore oil exploration: Texas, Louisiana, and the west coast of Florida.

[12] Oil from state offshore wells makes up less than 2% of domestic oil production in 2011. (The EIA does not separately book-keep state offshore oil production after 2011 [77].) Gas from state offshore wells makes up less than 1% of total domestic marketed gas production in 2012 [78]. Marketed gas from state offshore fields is dominated by the Gulf of Mexico, with Alaska accounting for 16% and California for 2% [78]. Considering gross withdrawals can be misleading, since these are dominated by Alaska, where nearly all withdrawn gas is pumped underground for re-pressurizing rather than extracted for sale.

well development (e.g. Spud Date or Completion Date). This criterion excludes wells that are drilled but uncompleted (DUC) or completed but not producing (COB) [84–86]. The resulting set of wells considered active in 2012 makes up 27% of the 2018 Drillinginfo database.[13]

Validating well counts based on oil and gas production. We can indirectly validate our method for selecting active wells by comparing aggregate production recorded in Drillinginfo against EIA values for U.S. domestic oil and gas production. We cannot however compare values for 2012, since 2012 production is not recorded in the 2018 Drillinginfo database. Drillinginfo does include "Prior 12 month" production ("Prior" being Sep. 2017–Aug. 2018, which we term 2017'), but this value is smaller than that for 2012, since wells experience a well-known decline in production over time [87–90]. We therefore compare instead 2017' Drillinginfo and 2017 EIA production estimates. That is, we inventory all wells active in August 2018 by the same methodology and assess their mean per-well "Prior 12 month" oil and gas production. This method yields total domestic production estimates that are 92% and 97% of EIA values for oil and gas, respectively.[14] We take this agreement as validation of our well selection methods.

3. Determining well production type: We then divide wells into two classes, as "oil" or "gas", based on their production data. This distinction plays only a minor role in cost estimation, since per-well costs are assumed to be identical regardless of a well's production type. Production type is relevant to costs only for non-horizontal wells in shale plays after 2003, where classification as oil or gas determines whether the well should be treated as fracked or unfracked. Distinguishing between oil and gas wells is complicated by the fact that many wells produce both fuels.[15] Wells are typically labeled as "gas" or "oil" depending on the ratio of their products, known as the "gas-to-oil ratio" or GOR. Since one barrel of oil has an energy content equivalent to 6000 cubic feet or 6 MCF of natural gas, a GOR value of 6 MCF/bbl would mean that a well produces equal flows of energy in the form of gas and oil.

State and federal agencies differ in the GOR values used for categorizing wells. The EIA uses the equal-energy GOR cutoff of 6 in a 2017 special report "The Distribution of U.S. Oil and Natural Gas Wells by Production Rate" [91]; Montana uses 10 [92]; Oklahoma uses 15 [93]; Texas and Pennsylvania use 100 [94, 95] as does the Environmental Protection Agency (EPA) since at least 2013 [96]; and North Dakota does not specify the distinction between oil and gas wells at all. Note that with the EPA's GOR cutoff of 100, a well can be labled as "oil" despite producing 100/6 or ∼17 times as much energy in the form of gas as of oil. In this work we use the equal-energy GOR cutoff of 6. Our low cutoff means that some wells with state-assigned DrillingInfo Well Production Type "oil" are counted in our inventory as "gas" instead.

Calculating GORs is complicated by the fact that GOR generally rises over the lifetime of a well, as oil production declines more rapidly than gas. We prefer to define well types based on GOR in 2012, but Drillinginfo production data is often incomplete. The DrillingInfo database provides numerous production measures related to different times and timescales. To cope with inconsistent data, we define a selection order for which production measures to use, depending on availability. In declining order of preference, we use Prior12, Latest, Cum ("Cumulative"), Peak, First 60 (months), First 12, First 6, First Month, Prac IP (the first whole month after the first production date), and Daily. Since many agencies use a code of -1 to indicate no production, for consistency we regard all negative production entries as zeroes.

[13]Excluded wells include producing wells abandoned before 2012 (28% of the 2018 Drillinginfo database) or completed after 2012 (4%), and wells with neither production data nor recorded latest production date (41% of the database, of which wells with some spud or completion dates but no recorded first or latest production date are 28% and those with no dates of any kind are 13%.) Wells with no production data overwhelmingly carry Well Production Type entries that suggest inactivity, with over 3/4 of entries as 'Inactive', 'P & A', and 'PA' (Plugged and Abandoned).

[14]2017' oil production is 8.7 M bpd in Drillinginfo vs. 9.4 M bpd from EIA; gas production is 32 TCF/year in Drillinginfo, vs. 33 M TCF/year EIA reported gross production. We assume that Drillinginfo values are "gross" gas production, inclusive of natural gas liquids (NGLs) that are later removed.

[15]The distinction is especially problematic in more recent hydraulically fractured wells. Fracked gas wells are notably "wet": they produce not only the single-carbon dry natural gas (CH_4) and the long-chain hydrocarbons of crude oil but substantial quantities of intermediate natural gas liquids (NGLs), e.g. ethane, butane, and pentane. NGLs are book-kept at the wellhead as part of gross gas production, but after processing and removal are treated as liquid fuels that are part of the petroleum fuel stream.

4. Identifying fracked wells: Because DrillingInfo does not provide explicit labels that describe stimulation methods, we identify hydraulically fracked wells based on a combination of well direction, location, and date. We define fracked wells wells as either those horizontally drilled or those drilled in coalbed, shale, or tight gas reservoirs during appropriate time periods. This approach is similar to that used by the Environmental Protection Agency (EPA) in multiple reports [96–101]. (EPA differs only in omitting the time period restriction, i.e. they consider wells drilled in shale plays as fracked regardless of online date.)

We identify locations within or outside shale plays using EIA maps [102], which are sourced from USGS. These shale play maps are also used by the EPA in their reports. We take 2003 as the onset of significant modern fracking for gas wells and 2007 for oil wells, based on USGS reported trends in median annual water volumes for hydraulic fracturing over time for the US [57, 58]. While some of the wells in the Barnett shale play in Texas were fracked with a similar technique in the late 1990s, these are negligible in the total calculation [103]. We therefore assume that any vertical, directional, or unknown direction well within a shale play is fracked if its First Production Date is 2003/2007 or later.

We assume that all horizontal wells are fracked regardless of the reported first production date associated with the well lease. This assumption follows the practice of the EPA emission inventory, which also uses Drillinginfo [96], and is supported by conversations with industry professionals [59, 68, 69, 104]. Although 30% of horizontal wells have early (pre-2003/2007) recorded first production dates, we assume these are cases where an older well is later redeveloped (redrilled and fractured) while DrillingInfo retains the original first production date [103, 105].

Comparison with other sources. We compare our resulting count of fracked wells with two other sources that offer estimates of fracked well counts: a recent EPA study that also uses DrillingInfo [101], and an alternative inventory of fracked wells described in a series of USGS reports based on the proprietary Information Handling Services (IHS) database [56, 57]. The EPA study provides a consistency check on different releases of Drillinginfo, since it uses the 2014 rather than the August 2018 version used in this work. The EPA study evaluates new horizontal wells drilled in 2005 and 2012 and yields values ∼10% lower than those in the 2018 database (1,809 and 14,560 horizontal wells for 2005 and 2012, respectively, vs. 1,992 and 16,384 in the 2018 database). The similarity implies that fracked well counts are not heavily dependent on Drillinginfo version.

The USGS studies provide a less direct comparison, as they count all wells drilled between 2000-2012 regardless of their present state of activity. The IHS database used by the USGS, compiled from a variety of public and private sources, includes information on well stimulation (e.g., hydraulic fracking). See Table 6 for comparison of fracked well counts by wellbore direction in this work vs. the USGS inventory. The total number of fracked wells is reasonably similar in both (35% higher in USGS), but the USGS inventory contains substantially more vertical and fewer horizontal wells, which is difficult to explain. The use of the USGS count for fracked wells would slightly raise our total inventoried cost for U.S. oil and gas wells, by ∼$87 B or ∼5% of assumed total well costs.

# of fracked wells	this work	USGS
Horizontal	68,581	53,755
Vertical + Unknown	147,362	242,224
Directional	30,086	34,534
Total	246,029	330,513

Table 6: Wells assumed fracked in this work and in the USGS inventory based on the IHS database [56, 57]. The samples are slightly inconsistent, but this difference cannot account for the discrepancies. In this work, fracked wells are taken as all horizontal wells and all others that are within shale plays and drilled between 2003/2007 (for gas/oil) and 2012. USGS fracked wells shown here are the subset identified as fracked and drilled between 2000-2012, which may include some wells inactive in 2012. Note that assignment of wellbore trajectories differs between databases [106, 107]. USGS does not include "unknown direction" wells; we group together vertical and unknown direction from our inventory since they are treated identically.

B.4. Cost assignment by well category

As mentioned before, we use literature values to estimate per-well costs for four well categories: conventional vertical (#1), horizontal (#2), and offshore shallow and deep water (#8–9). Figure 4 shows collected data used. Costs for the remaining five onshore categories are derived based on those for #1–2.

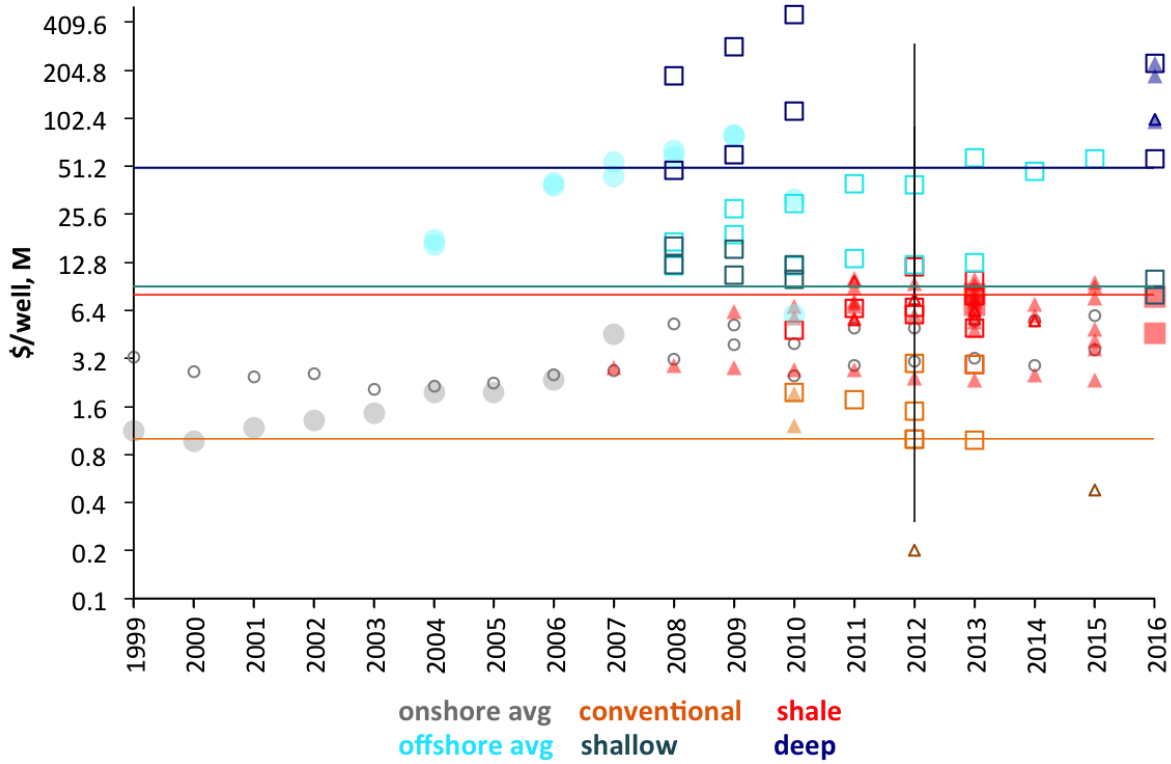

Figure 4: Collected estimates of US per-well development costs, 2000-2016, US $M per well in real 2012 dollars, displayed in log scale. (Log scale is needed because per-well costs differ by over two orders of magnitude between categories.) Cost assumptions for this inventory are shown as horizontal lines. Symbol color indicates the well categories; fill indicates formal (filled) vs. informal (open) sources; and shape denotes national (squares) or regional (triangles) estimates for individual well categories, or, for reference, national aggregate mean costs (circles). Informal sources include forum posts, press releases, phone conversation, and results derived from combining multiple sources. If cost data is given as a range, we record the two end points of the range. The JAS and IPAA series of Figure 3 are shown as grey circles, with JAS pre-2007 regarded as official (filled) and JAS post-2008 and IPAA as unofficial (open). (IPAA costs are derived from dividing annual expenditure by new well count.) Costs increase slightly over time across all categories with the onset of the shale revolution, and generally decline again after 2012. For conventional vertical wells, we choose a value more consistent with pre-shale-revolution costs than with 2012 costs inflated by limited labor and rigs during the shale boom [52, 108, 109].

Category 1, conventional vertical wells: $1M per well, range $0.8–2M

Estimates of the cost of conventional vertical wells differ by more than a factor of two. We conservatively assume a $1M per-well cost, a value on the low side of collected estimates but consistent with them. The spread in collected estimates (Fig 4) is also used to assign the uncertainty range. Our choice is informed by estimates of national average well cost before the onset of the shale revolution (pre-2003), when wells drilled were overwhelmingly vertical and conventional, but even here estimates diverge. Per-well costs from the API JAS [110], which are reported by the EIA from 1960-2007 [70], show a rising trend from $650,000 in 1980s to $1.2M in the early 2000s. (Per-well costs from IPAA [72] are higher and declining, to ∼$2M in the early 2000's, but we conservatively take the lower JAS estimates for assigning conventional well costs.) During the shale boom, even conventional well costs may be inflated by market effects. Estimates for non-shale

wellls in 2010-2012 based on API news releases range from $1.9-$1.6M in 2010-2012.[16] Regional estimates vary widely: detailed cost accounting in a 2011 Pitt Business Working Paper suggests a total of $0.9M for a vertical conventional well in the relatively shallow Marcellus shale [53].

Category 2, unconventional horizontal wells: $8M per well, range $6-10M

The $8M per-well cost is a mid-point value of estimates gathered in comprehensive reviews of US shale gas and tight oil extraction made by the Information Handling Services (IHS) firm ($8-9M in 2012)[52] and the Post Carbon Institute ($6-8M)[68, 69, 111]. The uncertainty range is based on these reports and on other formal and informal individual estimates of horizontal well costs shown in Figure 4. The wide range of costs reflects regional differences in shale formations and resulting well design and depth: as discussed above, horizontal wells in the Marcellus are shallower and therefore several $M cheaper than in other formations. We use costs for 2012 as our baseline, although horizontal well costs do show a declining trend after 2012 across all plays, possibly due to increased drilling and fracking efficiencies [52]. For example, the IHS range of horizontal well costs falls to $6-7M in 2016.

Category 3, vertical wells with likely fracking: $1.5M per well, range $1.1M–2.7M

After the onset of the shale revolution, we assume that many or most vertical wells drilled in shale formations make use of the new fracking techniques developed for horizontal wells [55, 112]. This assumption is supported by data showing a steep rise in the per-well volume of water used for fracking vertical wells (Fig 5). The USGS shows a rise from 200 m^3 in 2006 to 1800 m^3 per well in 2012 for oil wells, while gas rises from 200 to 500 m^3 [56, 57]. We therefore assume that vertical wells drilled in shale after 2003/2007 incur an additional cost over those of Category 1.

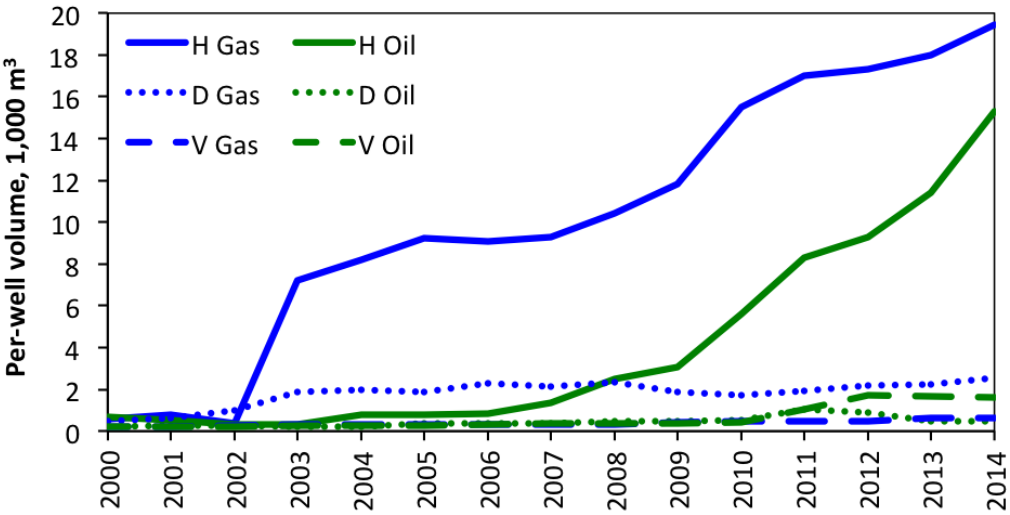

Figure 5: Median national annual per-well water volumes used (injected) to hydraulically fracture wells drilled from January 2000 to August 2014, differentiated by drill-hole direction (horizontal, directional, vertical) and final status (oil or gas). Data are from the IHS database summarized in a 2014 USGS research paper [57, 58], which includes n= 263,859 wells identified by USGS that use modern hydraulic fracking techniques.

Reported values for the cost of modern fracking in vertical wells are scarce and inconsistent. We estimate a $0.5M additional fracking cost and add this to the $1M development cost of conventional vertical wells for a $1.5M total cost. Some individual anecdotes can place the fracking cost considerably higher. For

[16]Publicly available API news releases include information on annual expenditure, annual new well completed, and the percentage of each for shale/non-shale. We combine these data to derive the annual costs per non-shale well for 2010, 2011, and 2012 ($1.9, $1.8, and $1.6M) shown in Figure 4 as as orange squares. See Table **??** for derivation and list of sources.

example, a report by the Interstate Natural Gas Association of America gives a $2M cost for fracking alone for a 2008 vertical tight gas well in the Green River basin in Wyoming ($6M total cost) [113]. However, industry professionals report smaller costs for fracked vertical wells [60, 103, 114], and simple scaling of costs based on fracking complexity also suggests lower values. Fracking cost is correlated with the volume of liquid and proppant used [52], and vertical wells use fewer fracking stages and therefore lower volumes than do horizontal wells [55, 115]. The USGS reported volume used for vertical wells in 2012 is only about 12% of that used in horizontal wells (Fig 5) [56, 57]. If the scaling is taken as linear, and fracking represents half ($4M) of horizontal well costs [52], then these ratios would suggest a fracking cost for vertical wells of ∼$0.5M. This approach yields a fairly uncertain estimate. True costs for this category would be pushed higher by any fixed costs of fracking that do not scale, and lower by the lower pressures used in fracking vertical wells. We therefore allow a wide uncertainty range.

Category 4, directional wells without fracking: $1.5M per well, range $1.1–2.7M
Category 5, directional wells with likely fracking: $2.5M per well, range $1.9–3.9M

A directional well is one whose wellbore trajectory deviates from the vertical, so that its total length - its "measured depth" - exceeds its vertical depth. The term "directional" is often thought of as describing a wellbore drilled in a single direction, while a "horizontal" well has distinct vertical and lateral sections, but in practice the distinction drawn between directional and horizontal wells is inconsistent across data sources, including the state agencies that contribute to the DrillingInfo database[17]. In the DrillingInfo database, the three wellbore directions (vertical, directional, and horizontal) are characterized by distinct distributions of measured depths (means of 5000, 8000, and 14,000 feet), with little variation over time (Fig 6).

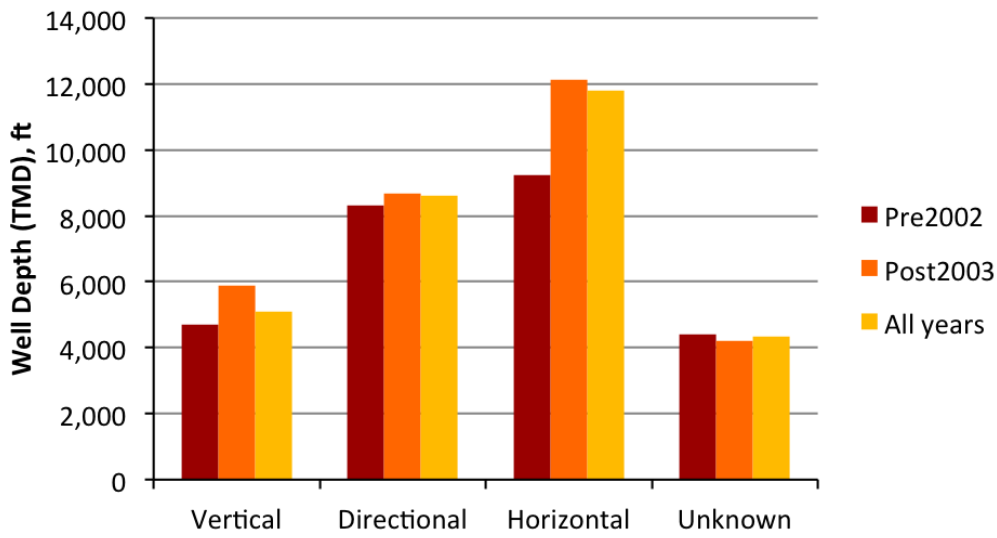

Figure 6: Average Total Measured Depth (total length along the wellbore trajectory) for different wellbore directions, from DrillingInfo 2018 [1]. We show all onshore wells with location and time information and depths greater than 100 feet, 90% of all wells. The figure here shows data for all locations, but depths do not significantly vary within and outside of shale plays.

We estimate the cost of directional wells by scaling up our previous estimates for vertical wells, accounting for higher drilling and fracking costs. We conservatively assume that the drilling cost per foot is the same for directional and vertical wells (in our inventory, $1M/5000 feet = $200/foot). While directional drilling incurs some additional cost per foot over vertical drilling (estimates range from 4-16% [117, 118]), those

[17]Directional drilling is often used to avoid a ground obstacle by drilling at an angle, or to drill multiple wellbores from a single platform, as opposed to the lateral drilling in horizontal well that enhances exposure area to the formation [116].

costs are likely offset by compensating efficiencies. The additional 3000 feet for directional wells thus yields ∼$0.5M additional cost.

As with vertical wells, we assume that early directional wells and those outside of shale plays are unfracked, but that directional wells in shale plays after 2003/2007 are likely fracked. We estimate the additional fracking costs for directional wells based not on wellbore length but on the volume of fracking fluid used. Fracking cost is correlated with the volume of liquid and proppant [52], and many industry sources report that directional wells often use the high-volume fracking (>100,000 gallons, or > 400m^2) [e.g. 119] that is characterstic of horizontal wells. However, USGS-reported fracking volumes for directional wells provide a confusing story. For gas wells, fracking volumes for directional wells exceed those for vertical wells by at least a factor of five (Fig 7). For oil wells, fracking volumes for directional wells actually drop below those for vertical wells after 2011. Because directional fracked wells in this inventory are disproportionately oil, any cost estimate will necessarily be uncertain. We estimate roughly that mean fracking costs in directional wells are double those in vertical wells, i.e. we double the assumed fracking cost to ∼$1M per well. We also augment the uncertainty range for category 5 by an additional $0.2M to account for uncertainty in this fracking premium.

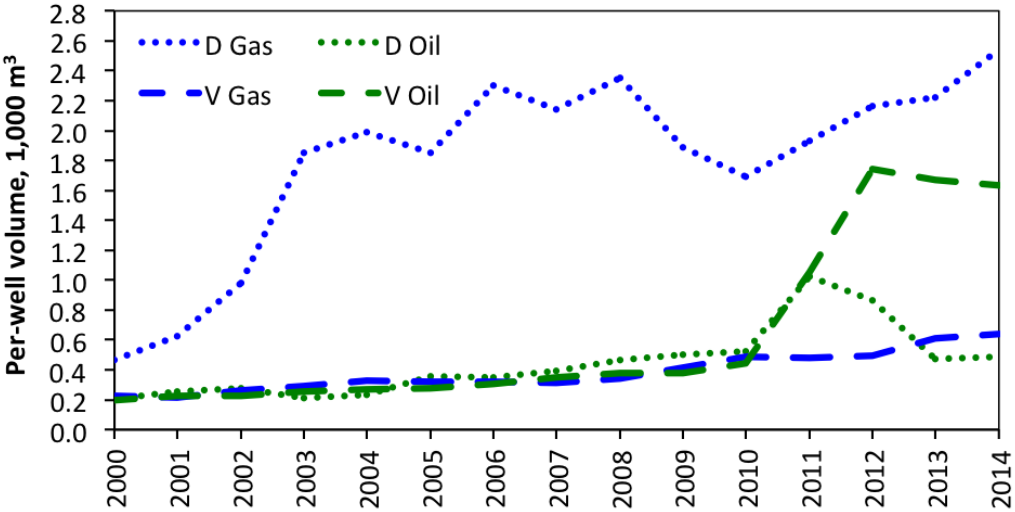

Figure 7: As in Fig 5: median national annual per-well water volumes used (injected) to hydraulically fracture wells drilled from January 2000 to August 2014, directional and vertical wells only. Data from USGS [56–58].

Category 6, unknown direction wells without fracking: $1 M, range $0.8–2M
Category 7, unknown direction wells with likely fracking: $1.5M, range $1.1–2.7M

Approximately 25% of the total active wells in our database do not have known wellbore trajectories,[18] but the shallow depths for these unknown direction wells strongly suggests that they are predominantly vertical (Fig 6). The distribution of well depths for unknown wells also is also similar that of vertical wells (Fig 8). Finally, the assumption of verticality is supported by the fact that older wells before the shale revolution are more likely to be classified as unknown direction. Before 2000, around 30% of each year's new active onshore wells drilled are listed as of unknown direction, but by 2010 the number has dropped to less than 10%. We therefore assign the same costs to unknown direction wells that we do to vertical ones. As with vertical wells, we assume that wells located in shale plays after the onset of the shale revolution are fracked and incur additional cost.

[18] All DrillingInfo data is reported by state agencies and is often inconsistent. See [106] for reporting methodology.

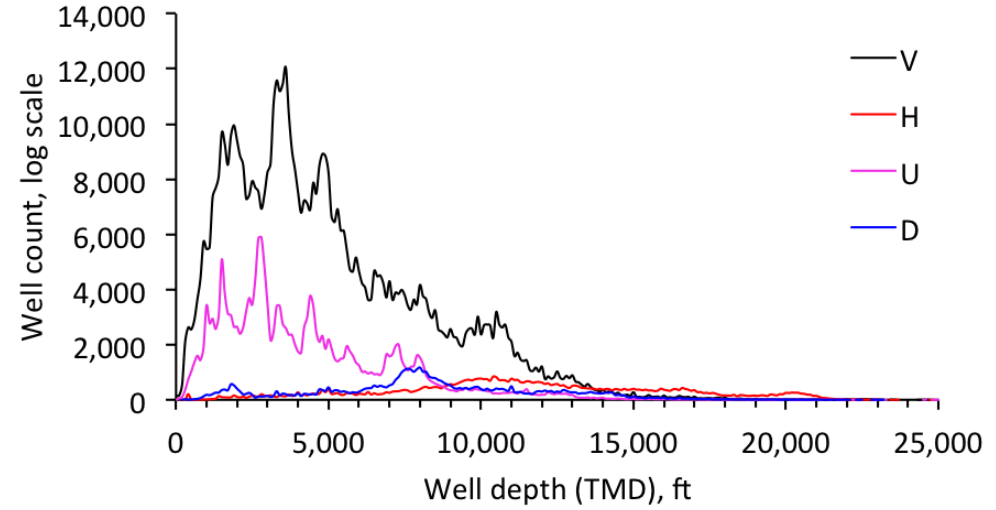

Figure 8: Distribution of Total Measured Depth (total length along the wellbore trajectory) for different wellbore directions, from the DrillingInfo 2018 data of Fig 6 [1]. Data are grouped with bin size of 100 feet.

Category 8, shallow water wells: $9M cost, range $8–10M
Category 9, deep water wells: $50M cost, range $30–200M

The cost of an offshore well is strongly dependent on water depth. Most U.S. offshore wells are drilled in relatively shallow water: 89% (4,442) of our BOEM-based inventoried wells are located in waters less than 1000 feet deep (Figure 9). By convention we term these "shallow water" wells, but the distinction between shallow and deep water is somewhat arbitrary. The remaining "deep water" wells, 11% (553) of our inventory, are distributed relatively evenly across an order of magnitude in water depth, to nearly 10,000 feet. Costs of individual deep water wells therefore vary strongly, and uncertainty in mean per-well cost is high.

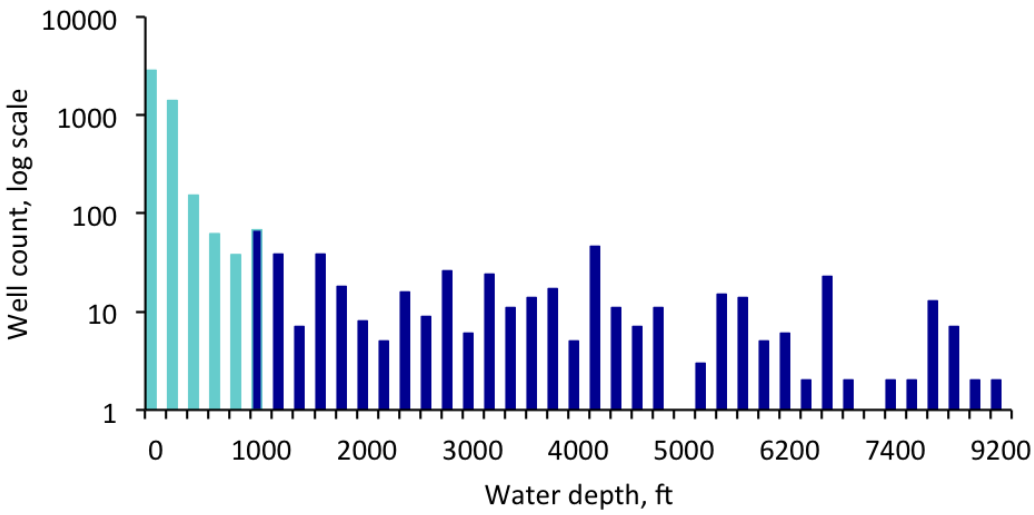

Figure 9: Distribution of offshore oil and gas water depth in our inventory. Water depth is measured in feet at the wellbore surface location (Note log scale on y axis.) The large spread in depths leads to a large spread in well costs. Source: BOEM [2].

The BOEM does not distinguish oil from gas wells, and we do not attempt to differentiate the costs of offshore wells by oil vs. gas. However, when bookkeeping total infrastructure costs by fuel type (e.g. manuscript Figure 2), we distribute costs of offshore wells between oil to gas categories using ratios provided by the IPAA: 85% to 15% oil to gas ratio for deepwater wells, and 60% to 40% for shallow water wells [120].

Because little detailed information exists on offshore well costs, we estimate their costs fairly crudely. A 2016 IHS report (commissioned by the EIA) suggests a range of $50-200M for deepwater wells [52], and staff in the IHS upstream oil and gas department suggest costs of up to $100M for deepwater wells and $8-10M for shallow water wells [66]. These estimates are broadly supported by other industry sources discussed below. Consistent with our general conservative approach, we choose baseline cost estimates for offshore wells on the low side of these collected estimates, at $9M for shallow and $50M for deep water wells.

We check these values against a variety of industry sources providing some information about national offshore well costs. No published sources provide aggregate per-well costs directly, but we can construct estimates by combining data on annual total capital expenditures and new well counts. For example, Quest Offshore, an energy consulting agency for the American Petroleum Institute, provides data that yield an average of ∼$13 M/ well for Gulf of Mexico offshore wells in a 2011 report *United States Gulf of Mexico Oil and Natural Gas Industry Economic Impact Analysis* [121]. This value will be dominated by shallow water wells. To differentiate shallow from deep water wells, we also combine annual capital expenditure data from DA Davidson & Co. [122] and annual well counts reported in Offshore Magazine [123]. These sources overlap for three years, 2008–2010, and produce mean per-well costs for shallow water of ∼$13 M and for deep water of ∼$200 M. Results are summarized in Table 7; our conservative cost estimates lie at their lower end. All derived national estimates, along with collected cost estimates for individual offshore well projects, are shown in Figure 4, and detailed information on sources is given in Section **??**.

	Cost ($M)	
Year	Shallow	Deep
2008	12-16	48-190
2009	11-15	61-289
2010	10-12	114-460
this work	9	50

Table 7: Derived offshore per-well costs for 2008–2010 based on reported timeseries of annual capital expenditure from DA Davidson & Co. [122] and new wells completed per year from Offshore Magazine [123]. We use digitizers to extract values from published graphs [124], and obtain a mean per well cost by dividing annual capital expenditure by annual new well count. Two sources of uncertainty mean we must report a range rather than point estimates. First, the well counts are categorized by three rather than two water depth classes – "less than 600 ft", "600–3000 ft" and "> 3000 ft" – and the central category potentially includes both shallow and deep water wells by our definition (shallow < 1000 ft). Second, the expenditure data is not sufficiently documented to make clear whether values are reported in nominal or real dollars. We generate a range of costs by assuming alternately that all wells in the "600–3000 ft" class are shallow or that all are deep, and by assuming that costs are in nominal or in 2013 dollars (the date of publication). Upper and lower bounds here are shown in Figure 4.

B.5. Costs per unit of production

Although capital costs for the different inventoried well types differ by nearly two orders of magnitude, their cost *per unit production* of oil or gas should be more similar. Since all these well types are currently being constructed, all must be economically viable, and so should have at least roughly similar ratios of capital expense to revenue. Determining the mean capital cost per oil and gas production for different well types can therefore serve as a consistency check on our cost assumptions. It also allows comparison with actual oil and gas prices and industry estimates of capital costs per unit energy prodution. To derive these values, we first combining our physical inventory with production data from the EIA to evaluate the cost *per production rate* of total U.S., onshore-only, and offshore-only oil and gas. (The EIA reports total [41, 78] and offshore [77, 125] oil and gas production rates; we infer onshore production rates by subtraction).

We then estimate the cost per unit production for these categories by assuming a well lifetime. (We assume a 20-year lifetime; see Section K for details.) Reults are summarized in Table 8. To facilitate comparison, gas production is converted to barrels of oil equivalent (boe) and all rates are given in $/boe.

Type	Well count	Asset value ($B)	Per-well cost ($M)	Prod (1,000 boe/d)	Prod/well (boe/d/well)	Cost/prod rate ($1000 per boe/d)	Cost/unit ($/boe)
onshore oil	434,801	613	1.4	5,231	12	117	16
onshore gas	599,660	1,036	1.7	12,522	21	83	11
offshore oil	3,143	41	13	1,266	403	32	4
offshore gas	1,852	24	13	931	503	26	3
total oil	437,944	654	1.5	6,497	15	101	14
total gas	601,512	1,059	1.8	13,453	22	79	11
total oil & gas	1,039,456	1,713	1.6	19,949	19	86	12

Table 8: Estimated capital costs per production rate and unit of production, derived from our physical inventory and EIA production estimates [41, 77, 78, 125–127]. EIA offshore production estimates are for federal offshore wells only, matching our definition. Gas production is converted to boe to facilitate comparison, and all rates are given as boe/day. The conversion factor assumes 6 mcf of natural gas are equivalent to 1 barrel of crude oil [91, 128]. We somewhat artificially attribute all oil production to oil wells and all gas production to gas wells. In reality, in 2012 ∼12% of onshore oil production is derived from wells labeled gas, and ∼7.5% of onshore gas production from wells labeled oil (when using the equal-energy GOR=6 cutoff), [91]. Our convention will therefore slightly depress the cost per production of oil wells and increase that for gas wells, by about 6% and 2%, respectively. Despite this bias, onshore oil wells in our inventory nevertheless have substantially higher capital cost per production. The more widespread use of modern hydraulic fracturing in gas production in 2012 means that onshore gas wells have higher cost per well, and corresponding higher per-well production rate. To derive unit costs, we assume a lifetime of 20 years for all wells, and constant production. See Section K for details of lifetime estimates.

Resulting capital costs per boe are broadly reasonable. Inferred capital costs per production are necessarily greater for oil wells than for gas wells ($14/boe vs. $11/boe in the national average), since we have assumed identical capital costs for each well type but a typical gas well has greater energy production than does an oil well.[19] This capital cost difference is economically reasonable, since the higher price for oil than gas allows profitable development of oil wells with lower production rates. The inferred capital costs of extraction in fact account for only a small fraction of the price for oil, but for nearly 70% of the wellhead gas price. (The "first purchase" price of domestic crude oil is $95 per barrel in 2012, while the wellhead gas price is $2.7/MCF or $16/boe.) See Section N for detailed comparison of capital cost estimates to prices.

Offshore wells have substantially higher assumed capital costs, but this cost premium is more than compensated for by their high production rates, 20–40 times those of onshore wells (Table 8 column 6). The result is that offshore wells actually have lower inferred per-unit capital costs than do onshore wells ($3-4/boe for offshore gas and oil wells vs. $11-16 for onshore). Some difference is expected, since operating costs for offshore wells are larger than those for onshore wells and must be balanced by lower capital costs. The large dscrepancy here may also suggest that our cost estimates for offshore wells are overconservative.

The resulting overall national inferred per-production cost for oil and gas production, $12/boe, lies within the wide range of cost estimates by industry sources (which typically aggregate oil and gas together). Ernst & Young reports per-well finding and development costs (FDC) higher than those here, at $19 and $16/boe in 2011 and 2013 (with an excursion to $44/boe in 2012, likely reflecting the market effects that we have sought to avoid). Rystad reports well and facilities (WF) costs lower than ours at $7/boe in 2016 (and $18/boe at the 2012 peak). The following Section C discusses industry capital cost estimates in detail.

[19] Note that the mean production rate per well in column 6 of Table 8 is driven not by the general tendency to higher energy production in gas wells for a given well type, but by the mixture of well types in the U.S. well fleet. In 2012, U.S. gas production includes a substantial contribution from expensive and high-producing fracked wells, but the later onset of the shale revolution for oil means that U.S. oil production remains more dependent on low-producing conventional wells. EIA production data [91] show the result of increasing penetration of fracking in the U.S. oil industry in subsequent years, with per-well production rates rising more strongly for onshore oil, at ∼30% rise between 2012 and 2016, vs. ∼15% rise for onshore gas.

C. Foreign oil and gas wells

C.1. Oil extraction: summary

In 2012, most oil and petroleum products consumed in the United States are imported: domestic oil production is 6.5M bpd, while net petroleum imports are 7.4M bpd [37, 38, 41, 129]. (See Table 2 for detailed flows.) Our inventory of infrastructure costs associated with U.S. fossil fuel usage must therefore account for the infrastructure used in producing oil elsewhere. The U.S. imports oil and refined products from more than fifteen countries, with Canada filling the largest share of U.S. demand (17%), followed by Saudi Arabia (9%), Venezuela (6%), and Russia, Iraq, and Mexico (around 3% each) [37, 38] (Figure 10).[20] The rates of import are well-documented and reported annually by the EIA, but we cannot conduct a physical inventory for multiple different countries. Instead, we construct factors that let us scale our U.S. infrastructure costs to derive a value for that part of foreign infrastructure dedicated to the U.S. oil supply.

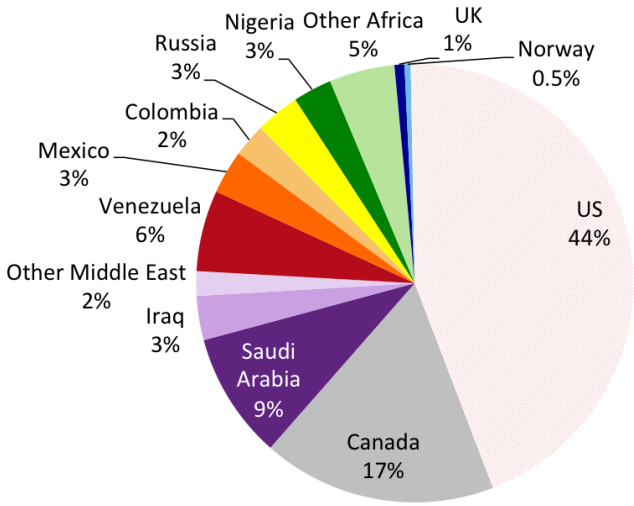

Figure 10: Contribution of supply from different sources to U.S. 2012 consumption of petroleum products. The figure is modified from the EIA [131] but with several major changes. First, we define consumption as domestic production + net import of petroleum products rather than as the EIA's "petroleum products supplied", which includes natural gas liquids, renewable fuels, fuel oxygenates, processing gain, and stock change and adjustments [132]. Second, we take into account the re-export of refined products to countries selling crude to the U.S., which reduces their share of U.S. supply. All data is sourced from the EIA: [37, 38, 41, 129, 130] and Table 3.1 in [133].

If the infrastructure requirements for producing oil were equal everywhere, the process for estimating foreign-oil-related asset value would be simple. We would simply multiply total U.S. net imports of petroleum products (in barrels per day, bpd) by the capital cost per production rate previously determined for the U.S. ($C_{\text{US}} = \$101{,}280$ / bpd, from Section B.5 Table 8). However, because the characteristics of oil deposits and labor/material costs differ between regions, capital costs for oil extraction can also differ markedly for individual countries. We therefore use a scaling procedure as follows. We first classify all countries into two groups, the "senders" (those whose exports of crude oil and refined products to the U.S. exceed their imports from the U.S.) and the "receivers" (the reverse). For each sender country (or group of countries) i, we evaluate its net export S_i in bpd, and estimate a factor f_{c_i}, the ratio of its upfront cost of oil extraction to that in the U.S. We then sum up the capital cost of U.S.-related oil extraction from all sender countries, summing $S_i \cdot C_{\text{US}} \cdot f_{c_i}$. As a final step, we impose an overall adjustment factor f_e that reduces this total to

[20] The percentage shown here is of combined U.S. production + net import of crude oil and refined products [129], not of total consumption [130]. See Figure 10 caption for details.

account for that fact that the U.S. ships petroleum products to "receiver" countries. The total infrastructure cost associated with foreign petroleum products consumed in the U.S. is then:

$$T_{\text{imports}} \;=\; f_e \times \sum_i (S_i \cdot C_{\text{US}} \cdot f_{c_i}) \tag{1}$$

The determination of f_e and the S_i's and f_{c_i}'s are discussed in detail below.

Net imports from "senders". While the U.S. relies heavily on imported crude oil, it is also a major exporter of refined petroleum products.[21] In some cases, crude oil import volumes are highly misleading, because the U.S. essentially serves as a petroleum refiner for foreign countries. Mexico is an extreme example: around 55% of U.S. import of crude oil from Mexico is refined in Gulf Coast refineries and immediately sold back to Mexico as gasoline [134]. Figure 11 shows this balance, displaying gross imports from foreign countries overlain with gross exports.

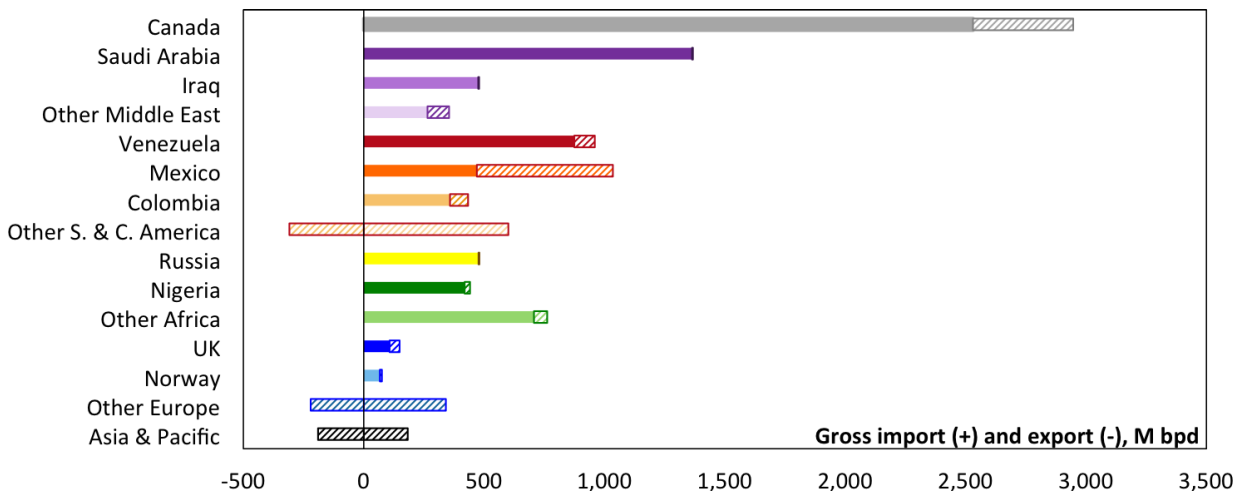

Figure 11: U.S. gross import and export of crude oil and refined petroleum products by country/region. We first draw gross imports as positive bars to the right, and then overlay gross exports as hatched bars extending leftward from the furthest point, i.e. subtracting from gross imports. Residual solid bars then represent positive net export to the U.S. from "sender" countries. Mexico, which effectively outsources much of its refining to the U.S., is a useful example. Mexico sends over 1000 M bpd crude oil to the U.S., but re-imports more than half of that volume as refined products, leaving a residual of only $\sim$ 500 M bpd [134, 135]. Countries or regions with hatched bars that extend to negative values (e.g. Asia & Pacific) are "receiver" countries. Color code is chosen to group countries in the same region with similar colors. The Middle East group (purple) consists of 16 countries, of which the U.S. imports primarily from Saudi Arabia and Iraq (shown separately), and Kuwait (included in "Other Middle East"). All data are taken from EIA data series on oil import and export by country [37, 38, 41, 129].

Net exports to "receivers". The factor f_e in Equation 1 adjusts the total foreign-oil-related infrastructure cost to account for the fact that the U.S. exports refined products to "receiver" countries. Its position in Equation 1 effectively assigns all these exports an infrastructure cost equal to that of mean imported oil. That is, we implicitly assume that all products sent to receiver countries are derived from imported oil that is pooled together, processed, and then re-exported. The adjustment factor is then

$$f_e \;=\; \left[1 - \frac{(\text{gross exports to receiver countries})}{(\text{net import from sender countries})}\right] \;=\; \left[1 - \frac{(1.29\text{ M bpd})}{(8.68\text{ M bpd})}\right] \;=\; 85\%$$

[21] In 2012, U.S. exports of petroleum products are nearly all refined products, not crude oil. The U.S. exported crude oil only to Canada and Mexico, in small cross-border transfers that likely resulted because individual refineries are specialized for processing different crude types. Crude exports had been restricted by law since the 1970s, but after U.S. domestic production expanded with the shale boom, these restrictions were dropped in the Consolidated Appropriations Act of 2016. By 2017 U.S. crude exports have expanded to more than 30 countries, including China and the U.K. [38, 129].

Capital cost differences across countries. The estimation of the f_c's is based primarily on a proprietary upstream oil and gas dataset prepared by the energy consulting firm Rystad, which estimates capital spending (expressed in cost per boe of combined oil and gas production) for 28 individual countries.[22] We use primarily the 2012 dataset, provided by Rystad [3], but supplement with information from a 2016 release reported in the Wall Street Journal [61]. Evaluation of the f_c's is described in detail the following section. Values range from 0.4–0.5 in the low-cost oil fields of the Middle East to 4.7 for the expensive North Sea oil from the United Kingdom. The Middle East no longer dominates U.S. foreign oil supply in 2012, and most countries from which the U.S. imports oil incur capital costs of oil extraction slightly higher than the U.S., leaving the weighted average f_c from sender countries at 1.2. Results are summarized in Table 9.

Region	f_c	Production (Thousand bpd)	\$1,000 / bpd	Subtotal (\$B)
US	1.0		101	
Canada	1.3	2,530	129	328
Saudi Arabia	0.4	1,364	44	60
Venezuela	1.0	875	99	87
Russia	0.9	477	90	43
Iraq	1.4	476	139	67
Mexico	1.3	470	134	63
Nigeria	1.7	419	171	72
Colombia*	1.7	358	174	63
Other Africa	1.7	747	170	128
Other Middle East	0.5	356	51	18
Other S.&C. America	2.0	248	205	51
UK	4.3	107	429	46
Norway	2.5	67	247	17
Other Europe	3.4	101	338	34
Asia & Pacific	1.7	83	175	15
Total	1.2	8,678		1,093
Total w/ f_e		7,393		931

Table 9: Summary of foreign extraction costs of U.S.-serving oil. For each sender country, columns show oil extraction cost factor f_c, net import rate S_i in thousand bpd, derived cost per production rate $C_i = f_c \cdot C_{US}$, and total infrastructure value $C_i \cdot S_i$. U.S. oil extraction infrastructure cost per production rate is derived in Table 8 ($C_{US} = \$101,280$/bpd). The primary source for cost fators f_c is the 2012 Rystad dataset [3], but we use 2016 values for the U.S. and Canada, which are heavily inflated by market effects in 2012 [61]. Countries are evaluated individually wherever data is available, but for simplicity we show some country groupings here (e.g. "Other Africa"). Where data is not provided, countries are given the unweighted regional average. To produce the values shown here for country groupings we then take the weighted average of relevant countries. * Rystad does not report data on Colombia; we use the average cost factor for South and Central America.

C.2. Oil extraction: scaling regional costs

A variety of datasets provide information about the capital costs of oil extraction in different nations or regions (Figure 12). Our primary sources are the 2012 and 2016 Rystad datasets described above [3, 61], but we compare these values to additional reports from the EIA and from Ernst & Young (EY) that estimate finding and development costs (FDC) based on the public financial filings of major oil and gas producers. Both are relatively comprehensive: the 2009 EIA report [136] drew on filings from U.S. companies accounting for nearly half of global upstream spending in 2008 [138], and the 2014 EY *Global Oil and Gas Reserves Study* [137] uses information from producers responsible for ∼10% of the global oil and gas reserves. Sources are not strictly comparable. FDC values include exploration costs and so should be higher than the Rystad values, which should be more similar to this inventory (though in fact they are lower). Biases due to methodological differences should however be unimportant when comparing cost ratios across countries.

[22] Rystad 2012 provides individual country data for the U.S., Canada, Russia, and *South & Central America:* Argentina, Brazil, Mexico, and Venezuela *Middle East:* Azerbaijan, Kuwait, Iraq, Kazakhstan, Oman, Qatar, Saudi Arabia, and Turkmenistan, United Arab Emirates, Iran *Africa:* Algeria, Angola, Egypt, Libya, and Nigeria *Europe:* Norway and the U.K. *Asia & Pacific:* Australia, India, Indonesia, Malaysia

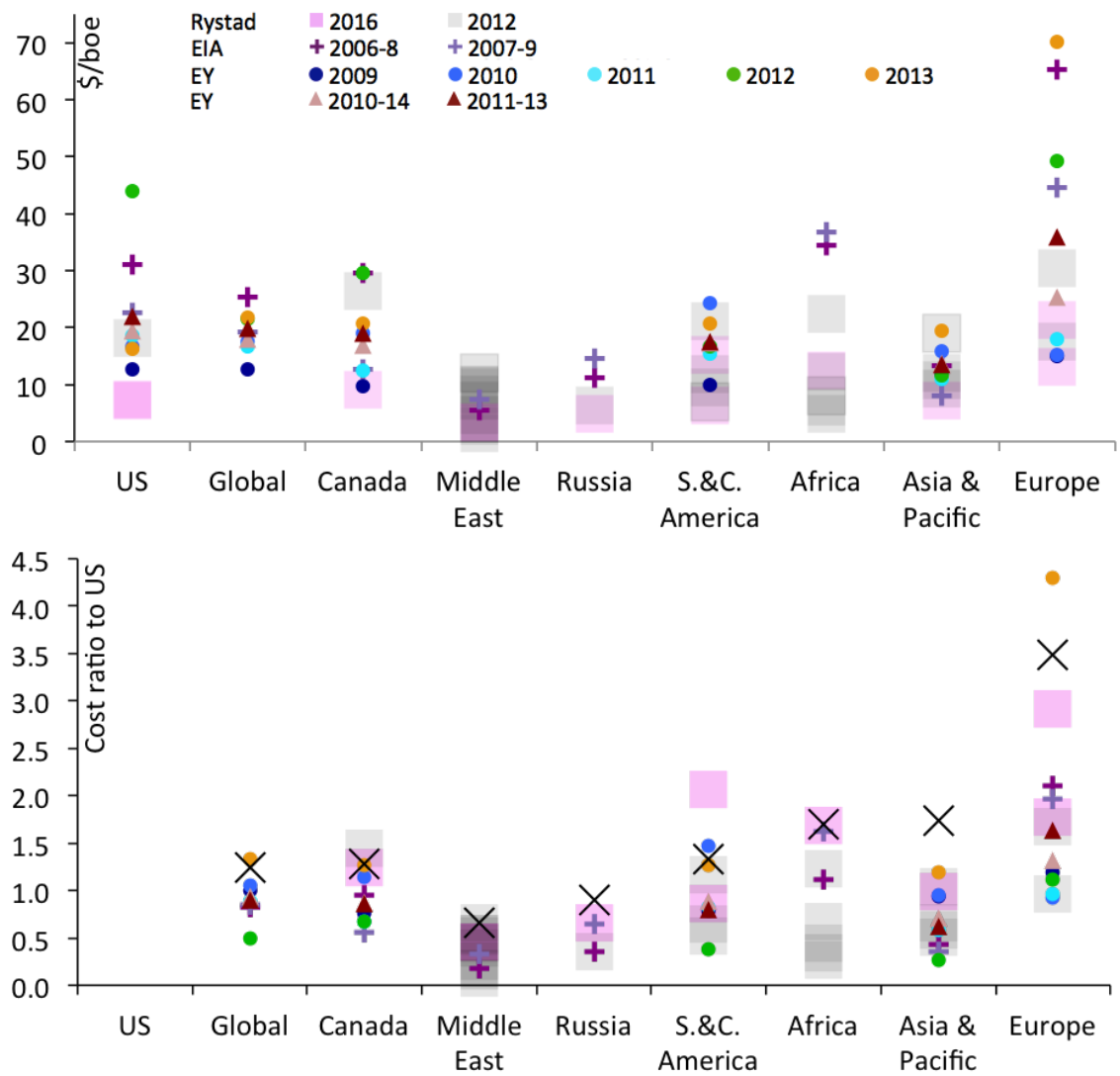

Figure 12: Comparison of regional well development cost estimated by different sources, expressed as **(top)** cost per boe, and **(bottom)** cost ratio vs. the U.S. for each individual source. In bottom panel, f_c values used in this work are shown as black crosses. Sources are: Rystad 2012 and 2016 WF (well and facility) cost for individual countries [3, 61] (squares) and regional aggregated FDC from EIA (crosses) [136] and Ernst & Young (dots, individual years 2009–2014 and triangles, ranges of years) [137]. Rystad country costs are shown as individual values in their appropriate regional categories. Both EY and EIA report regional groupings (other than for the U.S. and Canada) but groupings are not identical, and not all are shown here. (The EIA divides the remainder of the globe into Europe, Russia, Africa, the Middle East, Other Eastern Hemisphere, and Other Western Hemisphere; EY chooses Europe, Africa and the Middle East, Asia-Pacific, and South and Central America.) **Top:** Sources broadly agree on regional variations, but with considerable scatter. Rystad values are systematically lower than EIA and EY. No clear trends over time are evident, but costs in Canada and the U.S. spike in 2012 (green dots). For this reason we use their 2016 values in calculating f_c's. **Bottom:** Inflated U.S. costs in 2012 make cost ratios in 2012 systematically low (green dots, grey squares). Dividing by 2016 U.S. cost instead (black crosses) produces more appropriate values in most cases. The method likely fails in Asia & the Pacific and Europe, but imports from these regions are small.

All sources are compared in Figure 12. The EIA and EY reports cover multiple years: for the EIA, 2006–2008 and 2007–2009, and for EY, individual years 2004–2014 and 3- and 5-year periods centered around 2012. Sources broadly agree on regional cost variations, e.g. higher costs in Europe and lower in the Middle East, but show considerable scatter, including large year-to-year variations. No general time trends are evidenct, but costs in the U.S. and Canada, its largest exporter, show sharp jumps in 2012.

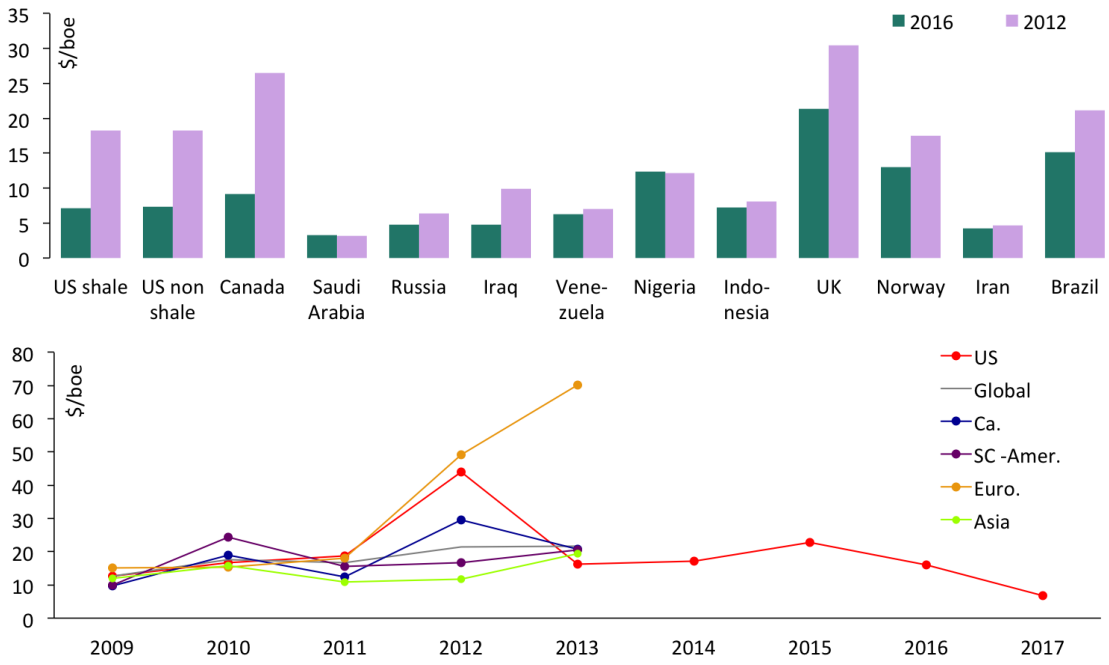

Figure 13: Comparison of capital costs for oil and gas extraction over time, showing a rise in 2012. All costs are expressed in $USD 2012. **Top:** Rystad well and facility costs [3, 61] ($/boe) in 2016 (green) and 2012 (purple), for those countries available in both sources. 2012 costs are significantly higher in the U.S. and Canada. **Bottom:** Finding and development cost (FDC) over time, from the Ernst & Young *Oil and Gas Reserve Study* series ([137] for 2009–2014 and [139] for the U.S. only from 2015–2018). U.S. and Canada costs appear relatively flat over time, except for a jump in 2012.

The cost jump in 2012 appears real and associated with the market effects of the U.S. shale boom. It is seen more clearly in Figure 13, which compares the 2012 and 2016 Rystad values (top) and shows trends over time in EY costs (bottom). In both datasets, 2012 stands out as an anomaly for the U.S. and Canada. In EY data, U.S. costs in real dollars are nearly flat over time other than the spike in 2012. That spike is also consistent with the rise in the cost of domestic wells around 2012 seen in the collected sources of Section B Figure 4. For this reason we use 2012 Rystad costs for all other countries, but substitute the 2016 costs for the U.S. and Canada. We calculate the f_c factors shown in Table 9 (and in the bottom panel of Figure 12) by dividing the capital costs of individual sender countries by that of the U.S. Countries not included in the Rystad database are given their unweighted regional average.

The weighted average cost factor for all countries from which the U.S. imports petroleum products is then $\overline{f_c} = 1.24$, as shown in Table 9. That is, we assume that the weighted mean capital cost of oil extraction is 24% higher in the countries from which the U.S. imports. A value larger than 1 is not surprising: the largest U.S. trading partner, Canada, with its heavy tar sands crude, is generally assumed to have higher capital costs than the U.S. The exact value of $\overline{f_c}$ has considerable uncertainty, however, given the disagreements between the sources shown in Figure 12.

With these assumptions, the total estimated asset value of U.S.-serving foreign oil extraction infrastructure is:

$$\text{Cost}_{\text{For. oil}} \;=\; 0.85 \times 1.24 \times 8.678 \text{ M bpd} \times \$101,280/\text{bpd} \;=\; \$\mathbf{931\ B}.$$

C.3. Natural gas extraction

The U.S. relies less on foreign production of natural gas than oil, but net imports of natural gas are still significant, equivalent to 6.0% of U.S. production (wet) in 2012 (Table 2). Essentially all travel from Canada by pipeline. (Imports of liquid natural gas from overseas are negligible in 2012.) As with oil, we do not conduct a physical inventory of Canadian natural gas extraction but instead scale U.S. gas infrastructure costs to derive a value for that part of Canadian infrastructure dedicated to the U.S. gas supply.

No systematic studies examine the relative capital costs of producing natural gas in Canada vs. in the U.S. As discussed in Section C.1, several studies by public and private organizations compare U.S. and Canadian capital costs for both oil and gas aggregated. These provide some guidance, but costs for oil extraction in Canada, which produces heavy crude from tar sands, are likely significantly higher than for gas. Canada's National Energy Board (NEB) publishes estimates of capital costs per boe for gas extraction from all major gas plays, but these values are not directly comparable to the U.S. cost estimates in this inventory, in part because they include land costs. In general, comparing different studies of extraction capital cost estimates is difficult, because studies vary widely in which components are included and how they are treated. We show collected cost estimates in Figure 14, along with the implied Canada/U.S. cost ratio where applicable. While recent Canada/U.S. cost ratios for aggregated oil and gas are greater than 1, NEB estimates for Canadian gas extraction alone are broadly similar to our inventory U.S. mean onshore value of $11/boe.

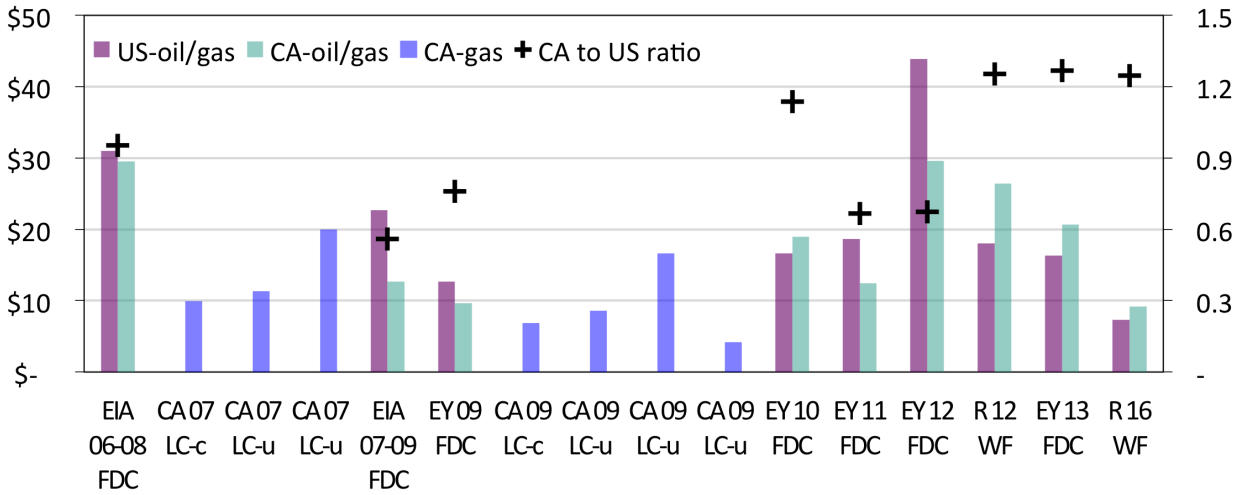

Figure 14: Comparison of well development related costs from 2007–2016 in units of cost per barrel of oil equivalent, from collected studies by private and public organizations. Ratio of Canada to U.S. costs are shown as black crosses. Sources: EIA = U.S. Energy Information Agency [136]; EY = Ernst & Young [137]; CA = Canada National Energy Board [140]; Rystad [3, 61]. NEB values in Canadian dollars are adjusted to US dollars through exchange rates published by the Federal Reserve [141]. Values from EIA, EY, and Rystad are also shown in Figure 12. NEB provides separate cost estimates for six Canadian gas plays, denoted as conventional ("c") or unconventional ("u"). Source methodology is denoted by finding and development cost (FDC), land and capital cost (LC), or well and facility capital expenditure (WF); the expectation would be that FDC > LC > WF. Estimates here show wide discrepancies that are not explained simply by methodology.

The inconsistencies in Figure 14 mean that no definitive cost ratio between Canada and the U.S. can be determined. The generally low NEB gas-only estimates do suggest that Canadian gas extraction capital costs are lower than those for oil. We make the simple default assumption here that capital costs for gas extraction in Canada are equal to those in the U.S. That is, we simply use the total asset value associated with U.S. gas extraction of $1055 B (Section B) and scale by relative volumes of production. The estimated asset value of U.S.-serving Canadian gas extraction infrastructure is then:

$$\text{Cost}_{\text{Can. gas}} = \$1055\text{ B} \times 0.060 = \mathbf{\$63\ B}.$$

D. Oil and gas pipelines

D.1. Summary

Pipelines are the leading transportation method for natural gas, crude oil and petroleum products. Essentially all natural gas consumed in the U.S. is moved through pipelines, as is almost 90% of U.S. oil and petroleum that moves across state lines[23]. Pipelines therefore comprise a substantial part of the inventory of fossil-fuel-related asset value. We derive physical information on U.S. pipelines from the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) 2018 database [4–6], which compiles annual mandatory surveys from pipeline operators and reports pipeline mileage, diameter, date of first operation, and commodity transported. We count pipelines operational in 2012.

We book-keep five U.S. pipeline types separately, and estimate separate costs for each. *Oil pipelines* are generally long-distance ($\sim$ 200 miles) transmission lines that carry crude oil to refineries or petroleum products from refineries. Natural gas pipelines are diverse, since natural gas is brought all the way to the consumer by pipeline, and are classfied by PHMSA into *transmission*, *gathering*, *distribution*, and *service*. Gathering pipelines carry natural gas from wells to processing plants or storage. Transmission pipelines are typically large-diameter and carry gas over long distances. Distribution and service lines are typically small-diameter (1-3"), but extensive: combined, these make up 87% of U.S. natural gas pipeline mileage. We do not distinguish between onshore and offshore pipelines, since their costs are similar.

Cost estimation for pipelines is difficult because pipeline projects vary widely due to multiple factors, including terrain, pipeline material and size, and regional differences in labor and material [145, 146]. One useful simplifying factor is that the cost of a pipeline scales nearly linearly both with diameter and length: doubling a pipeline's diameter or its length approximately doubles its cost. This near-linear scaling allows the costs of a diverse group of pipelines to be meaningfully described in units of \$/in-mile, where the inch refers to the pipeline diameter. [24] Costs for natural gas transmission pipelines are well-documented in mandatory reports to the Federal Energy Regulatory Commission (FERC) compiled by the Energy Information Agency (EIA) [7], and oil transmission costs should be similar to those for natural gas. Gathering pipeline costs are also relatively well-understood. Costs for small-diameter natural gas distribution and service pipelines are considerably more uncertain and must be estimated using unofficial sources. We assume costs of \$75,000 per inch mile for oil and gas transmission pipelines, \$40,000 for gas gathering, \$100,000 for gas distribution, and \$200,000 for gas service, for a total of **\$1.1T**. Table 10 summarizes the physical characteristics of the five pipeline categories (mileage, mileage-weighted mean diameter), the assumed costs per inch-mile, and the resulting book value. Sections below give details of the U.S. pipeline inventory and costs, and a separate estimate of \$14B for Canadian pipelines carrying crude oil and gas to the U.S.

Type	Diameter (inches)	Mileage (miles)	Unit cost (1000\$/inch-mile)	Subtotal (\$B)
NG Transmission	19	303,391	75	439
Crude Oil and Petroleum Product	13	181,366	75	170
NG Gathering	10	16,352	40	7
NG Distribution	2.4	1,247,470	100	301
NG Service	1.1	890,439	200	192
Total		2,639,018		**1,070**

Table 10: Summary statistics and costs for U.S. oil and gas pipelines. Diameters are mileage-weighted means from PHMSA [4–6]. Large-diameter gas transmission pipelines are the single largest component of total cost, though small-diameter distribution and service pipelines have much larger total mileage. The weighted mean cost across all types is $\sim$ \$130,000/inch-mile.

[23] We estimate that pipelines transport 88% of oil + petroleum products from EIA reports of volume transported between PADDs (Petroleum Administration for Defense Districts), which divide the U.S. into 5 regions [142, Table 37 & 38]. This measure emphasizes long-distance overland interstate transportation only. For gas, estimates of annual volume transported by pipeline (24T cubic feet) [143] approach the total 2012 U.S. natural gas consumption (25.5T cubic feet) [144].

[24] Longer pipelines do incur some cost savings; i.e. cost per inch-mile has a weak dependence on length.

D.2. Pipeline mileage and diameters

We use the most recent PHMSA database to obtain statistics on 2012 pipeline mileages. The various annual releases of the PHMSA database differ only very slightly [4–6, 147–152]. PHMSA data is primarily reported in three separate datasets, the "Hazardous & Volatile Liquids Annual Data" for oil [6] and for gas, the "Gas Distribution & Service Annual Data" and "Gas Transmission & Gathering Annual Data" [4, 5], which report information including pipeline mileage classified by pipe diameter size, commodity codes, first operation date, pipeline materials and corrosion control methods. For oil, we consider only commodity types "Crude Oil" and "Refined and/or Petroleum Product (non-HVL)" and "HVL" (31%, 34%, and 35% of inventoried mileage, respectively). We exclude "CO_2" and "Fuel Grade Ethanol (dedicated system)". Natural gas transmission, gathering, and distribution pipelines are fully described in separate tables by PHMSA. Book-keeping service pipelines is more complicated, since PHMSA [4] does not report lengths for individual service lines. We assume that all service lines are 71 feet in length, based on a separate report by PHMSA of total national service mileage [150] , which when combined with the number count implies a mean line length of 71 feet. Gas company reports suggest similar values [e.g. 153, 154]. Uncertainty in service line length is relatively unimportant to final aggregate cost because 98% of service lines fall into the smallest, least expensive diameter bin (1-2 inches). While pipeline costs should depend somewhat on material, and service and distribution lines may be either steel or polyethylene plastic, we do not distinguish between these since cost estimates are not typically disaggregated by material.

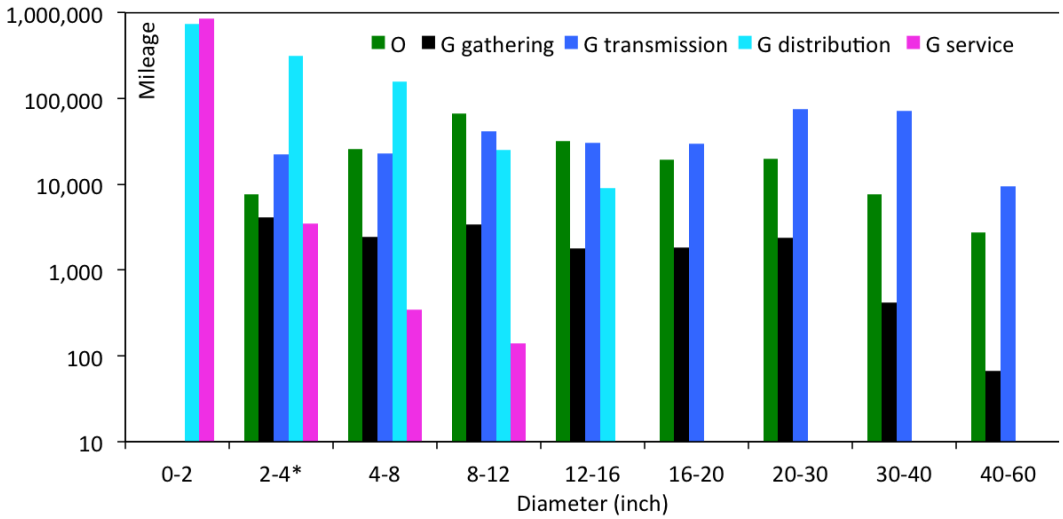

Figure 15: Histogram of pipelines in the PHMSA databases [4–6] by diameter for the five pipeline types, on log scale for clarity. (See text for details of pipeline classification.) For the 2% of PHMSA reported mileage that has no recorded diameter, we assign the mean diameter of each pipeline type. Oil and NG transmission and gathering pipelines reported as "under 4 inch" are placed in the "2-4 inches" bin. Total mileage is overwhelmingly dominated by small-diameter (1-2") gas service and distribution pipelines. The largest bin here includes the 800 mile, 48" Trans-Alaska pipeline that carries oil from Prudhoe Bay, and the largest-diameter U.S. pipeline, a short 5 mile, 56" segment owned by Louisiana Offshore Oil Port services.

The resulting distribution of our five pipeline types, by mileage and diameter is shown in Figure 15. We do not separately show offshore pipelines, as they make up only a small fraction of total mileage (4% of oil transmission and 2% of natural gas transmission), and their distribution of diameters is similar. (Weighted mean diameters for onshore and offshore pipelines are 14 and 16 inches, respectively, for oil transmission and 19 and 22 inches for gas transmission.)[25] As a check, we confirm that the resulting total mileage count is identical to an independent aggregation of total U.S. pipeline mileage by the PHMSA [149, 152].

[25]Offshore pipelines are significant only in the very minor category of natural gas gathering, which in total accounts for less than 1% of total U.S. pipeline mileage. For natural gas gathering, offshore pipelines make up 36% of total mileage, and their mean diameter (15 inches) is more than twice that of onshore gathering lines (7 inches).

For the purposes of cost estimation, we translate the histogram of Figure 15 into a mileage-weighted mean diameter for each pipeline type. PHMSA usually classifies diameters into relatively coarse bins (e.g., Unknown, 1IN, 1IN-2IN, 2IN-4IN, 4IN-8IN), but in some cases simply gives a threshold: "2 inches or less" or "4 inches or less". Where a bin is provided, we take the bin mid-point as the diameter (e.g. 1.5 inch for 1-2 inches). Where only an upper limit is given, we assign 1 inch diameter for pipelines classified as "1 inch or less", 1.5 inch for "2 inches or less", and 2 inches for "4 inches or less". We then weight each diameter group by its total mileage when taking the average:

$$\text{weighted average diameter} = \sum_{\text{diameter group}} \frac{\overbrace{\text{total mileage within range } \{D_{min}, D_{max}\}}^{\text{All types:erosion coating, onshore/offshore}}}{\text{Total mileage}} \underbrace{\frac{D_{min} + D_{max}}{2}}_{\text{midpoint diameter value}} \tag{2}$$

D.3. Cost estimation overview

Our choice of representative pipeline costs is informed by cost estimates from over 30 sources, including 5 national pipeline infrastructure cost studies [145, 146, 155–159], a database of natural gas transmission pipeline project costs reported to FERC between 1995–2018 and compiled by the EIA [7], and reports on individual projects that collectively list more than 100 projects. (Sources include the EIA [52], the Oil and Gas Journal [160–165], DOE [166], and individual construction reports and news releases [153, 167–185] along with PHSMA data [4].) Table 11 summarizes conclusions of the 5 national studies, and Figure 16 shows all collected cost estimates in units of $/in-mile, separated by pipeline type and diameter.

Report	Commodity	Date	Dia (inch)	Length (mile)	$M/mile	$1000/inch mile	Reference
Transmission							
ICF1	G	2011	30–36			94	[155]
ICF2	OG	2014				155	[158]
IHS1	G	2016	20, 30	200	1.8, 3.4	90, 115	[145]
IHS2	O	2016	12, 20	200, 450	1.5, 1.8	120, 90	[146]
ICF3	O,G	2017	36	280		223, 215	[159]
Gathering							
ICF2	OG	2014	1-16			24–122	[158]
IHS1	G	2016		25	1.3–1.7		[145]
Distribution							
IHS1	G	2016	4, 8	25	1.5, 1.3	330, 190	[145]

Table 11: National aggregate cost estimates of oil and gas pipelines, by the consulting firms IHS and ICF, from reports describing "sample" projects representative of the U.S. Costs are adjusted to 2012 dollars. ICF1, 2011 – *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*; ICF2, 2014 – *North America Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance*; ICF2 – a presentation slide with the same title; ICF3, 2017 – *Feasibility and Impacts of Domestic Content Requirements for U.S. Oil and Gas Pipelines*; IHS1, 2016 – *Economic Impact of Crude Oil Pipeline Construction and Operation*; IHS2, 2016 – *Economic Benefits of Natural Gas Pipeline Development on the Manufacturing Sector*. Some sources provide separate estimates for different pipe diameters; see Figure 16 for details.

The collected estimates of Figure 16 show that individual pipeline projects vary widely in cost, even for similar diameters. The various national mean cost estimates also differ, in part because costs have been trending upwards over time; the higher estimates are from more recent reports. (See Table 11 and Figure 17.) The information in Figure 16 does justify treating oil and gas transmission and onshore and offshore pipelines as equivalent, since there is little difference in their costs. Most collected cost estimates are for relatively large-diameter transmission projects. We have little official information on costs for the small-diameter (1–2") distribution and service pipes that dominate U.S. pipeline mileage. Cost estimates

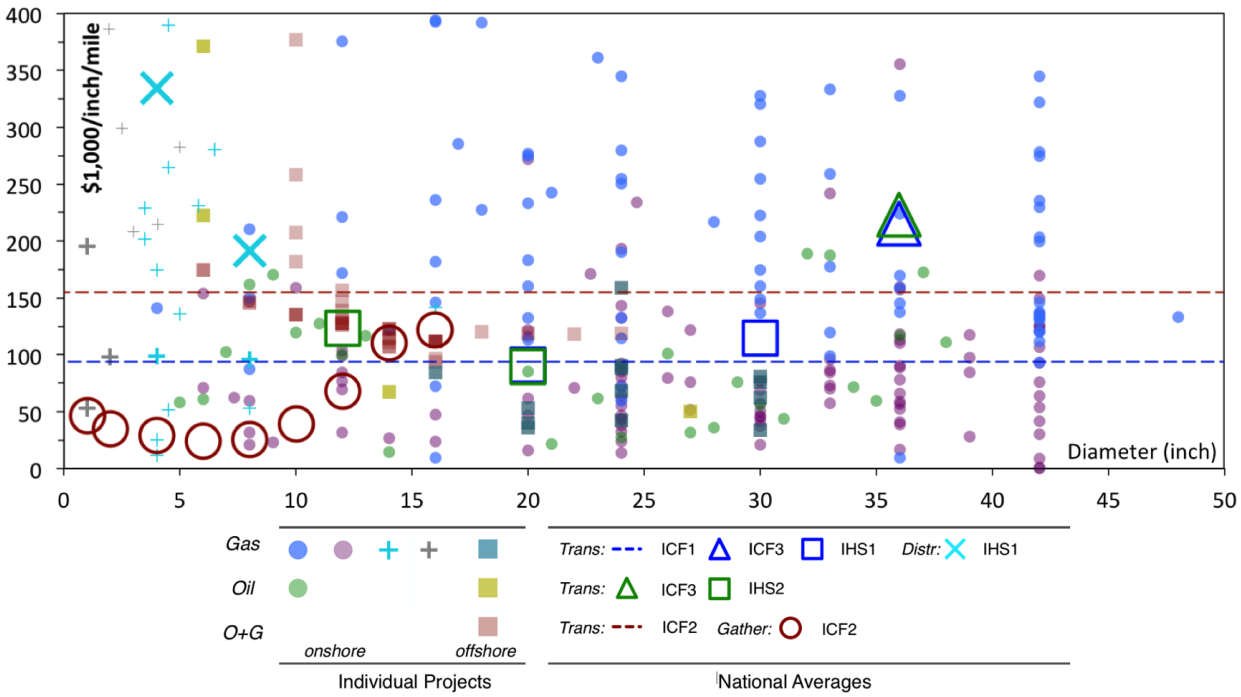

Figure 16: Collected costs per inch-mile for oil and gas pipelines plotted against diameter. Small symbols mark individual projects. Large symbols are estimates of national representative costs from reports between 2011–2017 summarized in Table 11. References ICF1–3 are from [155, 157–159], IHS 1–2 from [145, 146]. Lines are used for estimates of average cost across all pipeline sizes. Colors denote fuels: gas (blue/purple), oil (green), and both (brown). Symbols denote pipeline type and data source. Onshore gas pipeline individual project estimates fall in four groups: 1) the EIA dataset of FERC filings [7] (blue dots), 2) miscellaneous industry and news sources for general gas pipelines (purple dots) 3) estimates for distribution only (light blue crosses) and for service or distribution and service combined (grey crosses). The latter two groups can include expansion or replacement projects whose costs may differ from those of new projects. Smaller crosses are from derived estimates with larger uncertainty. Two of the larger grey crosses represent the same source [153], which does not state a diameter, for assumed diameters of 1" and 2". Some double-counting also occurs because some EIA/FERC filings (June 2013–June 2015) are also listed in industry and new sources. Cost estimates vary widely.

for small-diameter distribution and service pipes appear higher (in $/in-mile) than those for larger-diameter transmission, possibly in part because of their siting in urban areas, which increases installation complexity and therefore labor costs. While reported costs include land purchase or lease ("right of way" or ROW), these do not drive the difference between projects or between pipeline types, as ROW is typically only 3-4% of total project cost [186]. The bulk of costs are labor, the pipe itself, and equipment [7]. In the following sections, we describe in detail the determination of costs assumed in this inventory for each pipeline type, beginning with transmission, the best-documented pipeline type.

D.4. Transmission – natural gas

We estimate the cost of natural gas transmission pipelines using the database of project costs reported to FERC. Figure 17 shows costs for all completed new projects between 1995-2018, inflation-adjusted to 2012 dollars, that include information on diameter and mileage. The same data is shown in Figure 16, but here is organized by year rather than by diameter. This representation makes clear a strong temporal trend, with costs rising sharply following the onset of the fracking revolution, likely driven by increases in the the cost of both labor and steel. The Interstate Natural Gas Association of America (INGAA) and the Oil and Gas Journal, a leading trade organization and trade publication in the field, respectively, both

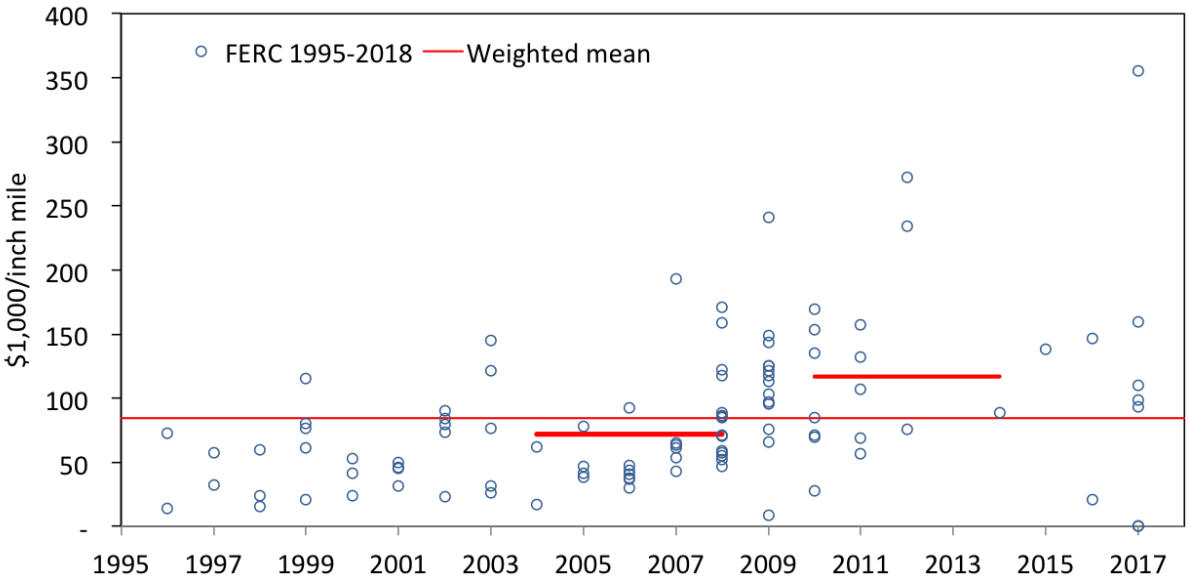

Figure 17: Reported costs for onshore natural gas pipelines from the EIA-compiled dataset of FERC filings [7], for all projects listed as "new systems" and "completed" that have recorded diameter, mileage, and costs. (Over 80% of filings are either of other type such as expansion or reversal, or are abandoned or in construction). Nearly all are transmission lines. Red lines show mileage-weighted mean costs per inch-mile for three time periods: 1995-2018 ($83,000), 2004-2008 ($72,000), and 2010-2014 ($117,000). Excluded project types include "mainline expansion", "lateral expansion", and "reversal"; costs for expansion projects show much greater variation. For clarity we also exclude offshore projects, which has the similar magnitude to onshore but could involve some extreme outliers: for example, the short Tenneco Deepwater Link Project of 2009, 1 mile of 22 inch pipeline for $40M, which yields a cost of $1,820,000 per inch-mile.

report an increasing cost trend over time [155, 156, 164]. Because we are seeking conservative cost estimates that avoid recent market distortions, we base our estimate for transmission pipelines of $75,000/inch-mile on mileage-weighted mean costs for projects from 2004-2008 ($72,000/ inch-mile) rather than on the higher costs closer to the benchmark inventory year of 2012. (Weighted mean costs for 2010-2014 are $117,000.) Our estimate is therefore also lower than the national estimates of Table 11.

D.5. Transmission – oil

While cost estimates for natural gas transmission pipelines are abundant [e.g. 7, 145, 163, 164], there are very few public, non-proprietary cost estimates for oil or petroleum product pipelines [146]. Petroleum as liquid is arguably less costly to transport than natural gas, as it need not be pressurized to the same extent [169], though both pipeline types are made of steel [187]. We see however no evidence of lower costs for oil vs. natural gas in the collected estimates of Figure 16: the weighted mean of all estimates is actually slightly higher for oil than gas, at ∼$100,000 vs. $82,000/inch-mile. Given the lack of information, we assume for simplicity that the costs in $/in-mile for all oil transmission are the same as those for natural gas.

Assuming equivalence of oil and natural gas transmission pipeline costs is a common practice. The 2014 ICF report on projected U.S. energy infrastructure investment, for example, gave a joint $155,000 inch-mile cost for oil and gas transmission pipelines [157], and many other publications also treat oil and gas pipelines together [e.g. 158, 188–190]. It is also standard practice to assume that costs for onshore and offshore pipelines are similar or equivalent, as we do here. The ICF 2014 report on projected U.S. energy infrastructure assigns regional factors for pipeline costs, and gives offshore a factor of 1.0 and onshore a range from 0.79-1.27 depending on region [157, 158].

D.6. Gathering

Natural gas gathering pipeline sizes vary greatly, from just a few inches to over 40" in diameter (Figure 15), and costs for gathering pipelines seem to show strong dependence on diameter. This variation makes $/inch-mile units less useful. The ICF reports sample project costs for gathering lines from $24,000 to $125,000 in 2012 dollars (for 6" and 16" diameter, respectively) [157, 158, 188, 189]; these are shown in Figure 16. We assume a cost of $40,000 per inch-mile for gas gathering, appropriate for the 11 inch weighted mean diameter of gathering pipeline in the PHMSA database.

D.7. Service

There are no official and national studes on the construction cost of gas service lines. Service lines are qualitatively different from other pipeline types, with extremely short lengths, which make any fixed costs of installation more significant. In the PHMSA database, mean service line length is only 71 feet, while median lengths for distribution, gathering, and gas and oil transmission are 49, 8, 18, and 40 miles, respectively. Combined with their small diameters (weighted mean 1.1") and typical installation in urban environments, we would expect service lines to incur higher costs per inch-mile than do other pipeline types.

Our estimates for service line costs are informed by a 2016 report by the Public Utilities Commission (PUC) of the state of Oregon on expanding natural gas service to underserved areas [153]. In Oregon, no city more than 15 miles from a natural gas transmission pipeline had gas service in 2016. The PUC therefore appointed an 11-member commission (the "SB 32 Work Group") to evaluate the feasibility of extending service. The resulting report suggests an average cost and length of service lines of $1,666 and 43 feet, i.e. $39/foot or ∼$200,000 per mile. Assuming a diameter of 1–2" implies costs of $200–100,000 per inch-mile (two large grey crosses in Figure 16). This new project cost is somewhat more expensive than service line extensions. The conventional rule of thumb for extensions of 1" pipe is $20–30/foot or $100,000-150,000/inch-mile. A report from the NorthEast Ohio company on gas line extensions [154] provides an even lower estimate, at $10/foot for 1" pipe or $53,000 per inch-mile (large grey cross). We adopt an estimate of $200,000/ inch-mile for service lines, but allow a wide uncertainty range of $75–300,000/inch-mile ($14–58/foot for 1" pipe). This uncertainty does not contribute significantly to overall uncertainty in pipeline inventoried upfront value, since service lines comprise only 8% of the pipeline physical inventory by inch-mile.

D.8. Distribution

Distribution pipelines are far more significant to the physical inventory, making up 25% of it by inch-mile, but there are again few reliable estimates of their costs. The only national cost estimates are for much larger pipes than the distribution norm: 8" and 4" pipe (largest blue x's in Figure 16), though the weighted mean diameter of gas distribution pipe in PHMSA is 2.4". These national estimates are extremely high at $190,000 and $330,000/inch-mile [145]. Individual project estimates in Figure 16 show a wide scatter, but tend to lower values. Most of these are derived from a DOE report summarizing recent replacement projects for gas distribution pipelines conducted by local distribution companies [166]. Two projects with full information (large blue crosses) yield costs of ∼$100,000/inch-mile, from Florida City Gas (the "Safety, Access, and Facility Enhancement" program) and the Philadelphia Gas Works company. Other estimates shown in Figure 16 are more informal (small blue crosses), derived by combining replacement project costs from the DOE report with mean company line length and diameter from the PHMSA database [4]. These average $178,000/inch-mile. Some replacement cost estimates can be significantly higher, presumably because of the expense of removing old pipe. For example, a 2017 DOE report on natural gas infrastructure modernization [166] suggests replacement costs for distribution mains of $1-5 million per mile, which would yield $200 K–$1 M/inch-mile for 5" pipe and still more if diameters were smaller. We assume for consistency that natural gas distribution costs must lie between inventory values for transmission ($75,000/inch-mile) and service ($200,000/inch-mile), and assume a conservative $100,000/inch-mile, with an uncertainty range of $50–150,000/inch-mile. This spread contributes significantly to uncertainty in the total assumed pipeline upfront value.

D.9. Foreign pipelines - oil transmission from Canada

Canada is the single largest supplier of foreign crude oil to the U.S., providing net imports equivalent to ∼36% of U.S. domestic production in 2012 (Table 2). All of this oil moves in pipelines, which must be included in any inventory of infrastructure related to U.S. fossil-fuel consumption. We assess here only the parts of U.S.-serving pipeline systems physically in Canada, since sections within the U.S. are counted in the PHMSA database and already included in our domestic pipeline cost estimate. For simplicity, we consider only the four main pipeline systems that connect crude oil resources in Alberta (and Saskatchewan) to the continental U.S.: the TransMountain pipeline, which carries oil to the West Coast, and the Express-Platte, Keystone, and Enbridge Mainline systems, which carry oil to the Midwest and further south [191–193] (Figure 18). These are described in detail below.

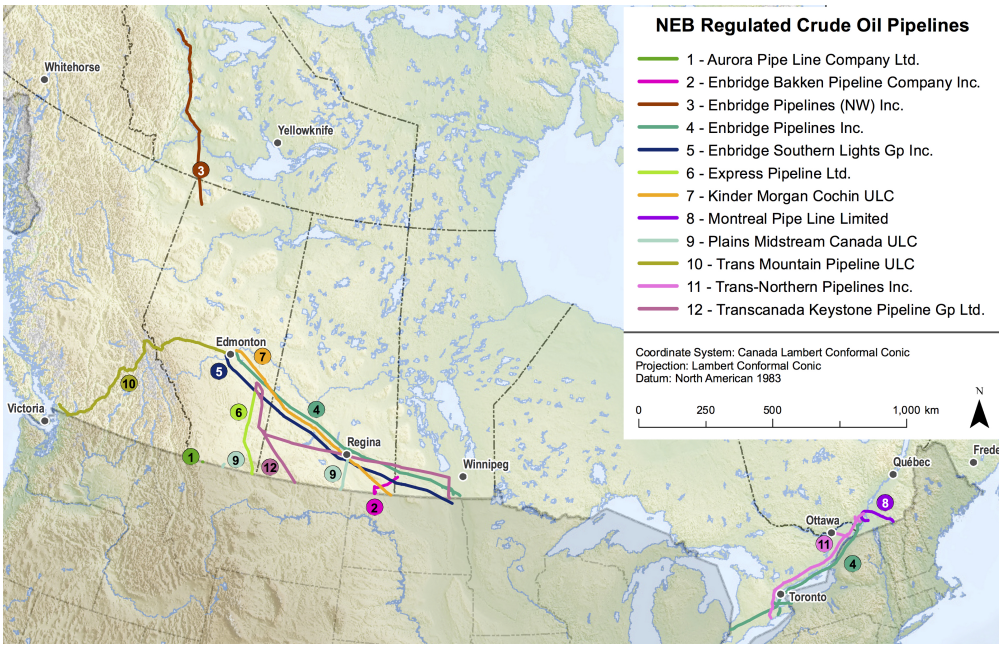

Figure 18: Major oil pipelines that deliver Canadian oil to the U.S. Four pipeline systems alone – Enbridge (4), Express (6) Trans Mountain (10), and TransCanada Keystone (12) – carry over 2 million barrels per day of crude oil to the U.S., primarily to IL, OK, TX and WA [194]. (The Enbridge Southern lights (5) and Kinder Morgan Cochin (7) carry a reverse flow of U.S. natural gas liquids and light hydrocarbons to Canada.) Figure courtesy of the National Energy Board of Canada [195].

Major Canada-U.S. oil pipeline systems

- The **Enbridge Mainline** system originates from Edmonton, Alberta, and crosses the U.S. border at Gretna, Manitoba en route to Superior, WI. It serves not only export to the U.S. but also intra-Canada transport – the system re-enters Canada at Sarnia, Ontario en route to Montreal – and carries a minor quantity of imported crude to Canada. We estimate mean throughput from data from the Canada National Energy Board (NEB), which reports throughput data by trade type, product, and transfer point. NEB classifications cleanly separate exports from domestic usage for light crude but conflate the two for heavy crude. We assume that all heavy crude oil in Enbridge is destined for the U.S. [196].

- The **Trans Mountain Pipeline**, first operational in 1953 and expanded in 2008, carries crude oil from inland Edmonton, Alberta across the Rocky Mountains to the West Coast of British Columbia. The pipeline lies almost entirely in Canada, but connects to the Washington State Puget Sound pipeline at the border close to the pipeline's Canadian terminus. We take the total Trans Mountain mileage for the purpose of cost assessment. The throughput correction for Trans Mountain is substantial, since

the majority of its oil goes to Canadian domestic consumption or to Canadian marine terminals for export to other international destinations [197]. We assume that no Trans Mountain oil is sent to the U.S. by tanker from marine terminals. Note that a significant expansion of this pipeline was proposed in 2013 and may be relevant in future inventories.

- The **Keystone Pipeline** originates in Hardisty, Alberta; its U.S. portion travels due south. As of the 2012 baseline year of this inventory, the pipeline reached only as far as Cushing, Oklahoma, but with completion of its Phase III expansion in 2014, Keystone now reaches the Gulf of Mexico [198–201]. (Keystone Phase I was completed in 2010 and Phase II to Cushing in 2011.) The connection to Gulf tanker terminals means that Keystone can now carry Canadian oil destined for overseas export, but in 2012 Keystone should serve only the U.S. market, so we assign a throughput of 100%.
- The **Express-Platte Pipeline** is generally described as two distinct segments, termed the Express pipeline in Canada and the Platte pipeline in the U.S. [202]. We take only the Express pipeline mileage and assume 100% throughput destined for the U.S. The Express-Platte was owned by Kinder Morgan in our baseline year of 2012, but was sold to Spectra Energy in 2013.

For these Canadian pipelines, no single database contains comprehensive information on pipeline length, diameter, or throughput (% of pipeline flow that crosses the U.S. border). We collect information from the Canada National Energy Board, from pipeline operators, and from regulatory agencies, summarized in Table 12 below. These sources do not allow calculating an exact mileage- and throughput-weighted pipeline diameter, but we estimate a reasonable average of 28 inches.

Name	Operator	Dia. (inch)	System length (mile)	Canada length (mile)	% to U.S.	Source
Enbridge Mainline	Enbridge	18-36	17,018	1,433	65	[196, 203–205]
Trans Mountain	Kinder Morgan	24,30,36	715	715	47	[197, 206]
Keystone	TransCanada	30	2,687	769	100	[198, 207]
Express-Platte	Spectra Energy	24	1,717	270	100	[202, 208]
Total (throughput weighted)		*28*		2,307		

Table 12: Major pipeline systems that deliver Canadian oil to the U.S. Mean diameter in the Enbridge pipelines included here is ∼30", and we assume 26" for Trans Mountain. The Express-Platte was sold to Spectra by Kinder Morgan in 2013. We do not assess asset value for transport of Canadian natural gas liquids, which enter the U.S. primarily by rail [195].

Applying our transmission pipeline cost estimate of \$75,000/inch-mile gives a cost for Canadian oil pipelines of \$2.25M/mile. Consistent with practice throughout this work, we apply a small adjustment to account for additional import of refined products from Canada. Net imports of crude and refined products from Canada exceed those of crude alone, by a factor (2.43 - 0.07 + 0.52 - 0.35)/2.43 = 1.04. (See Table 2.) The adjusted cost of U.S.-serving Canadian crude oil pipelines is then:

$$\text{Cost}_{\text{Can. oil pipe}} = 2{,}307 \text{ miles} \times 28 \text{ inches} \times \$75{,}000 \text{ /inch-mile } \times 1.04 = \mathbf{\$5.0\ B}.$$

D.10. Foreign pipelines - gas transmission from Canada

Canada is the only significant supplier of natural gas to the U.S., sending the equivalent of 8% of U.S. production by pipeline from Western Canada and Nova Scotia.[26] Almost all major Canadian gas pipeline systems play some role in carrying gas to the U.S. (Figure 19) [195]. We tally only the major lines whose U.S. throughput is large, and do not include systems that largely serve Canadian customers. We derive throughput ratios from the Canada NEB gas pipeline throughput & capacity database [195, 196], and use them to weight pipeline length. Results are summarized in Table 13 below.

[26]Net gas imports from Canada alone are equivalent to 8.3% of U.S. dry production or 0.9 M boe/day. Total U.S. net gas imports are smaller, 6.3% of U.S. production, because of U.S. exports (primarily to Mexico); we do not adjust for this here.

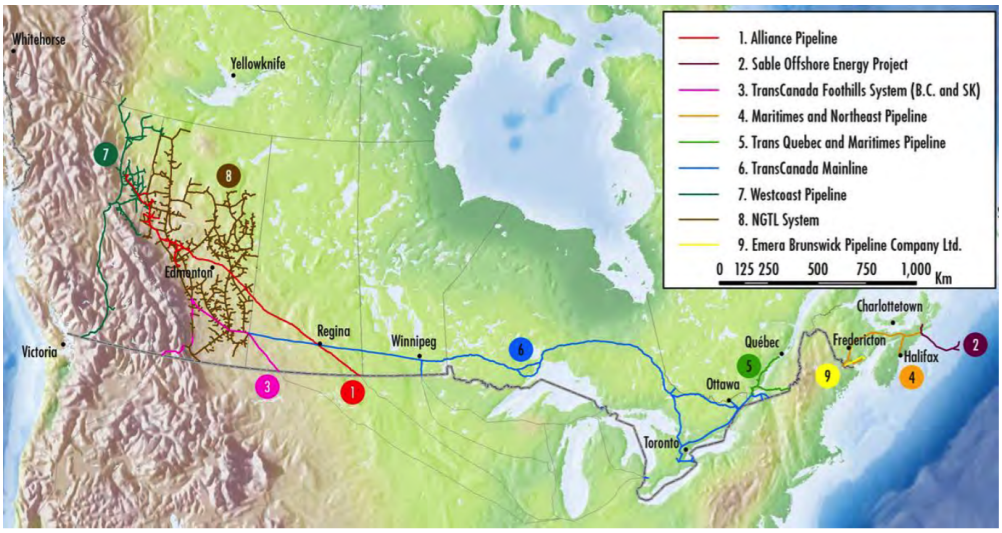

Figure 19: Major gas pipelines that deliver Canadian gas to the U.S. We include here the Maritimes & Northeast (4) and Brunswick (9) pipelines that carry gas from offshore Nova Scotia wells through New Brunswick and into Maine (from which it travels onward to Boston), and, in the West, the Alliance (1) and TransCanada Foothills (3) systems that carry gas from Alberta southeast to the U.S. border, and the Westcoast (7) pipeline from British Columbia into Washington state. Figure courtesy of the National Energy Board of Canada [195].

Name	Dia. (inch)	System length (mile)	Canada length (mile)	% to U.S.	Source
Westcoast	24-40	3,620	3,620	58	[209]
Alliance	42	209	209	77	[210]
	36	759	759	77	
TransCanada Foothill	up to 48	771	771	100	[211]
Maritimes & Northeast	27	553	337	72	[212]
Emera Brunswick	30	89	89	100	[213]
Trans Quebec & Maritimes	*24, 30*	*221*	*221*	*21*	[214, 215]
TransCanada Mainline	*up to 48*	*8,779*	*8,779*	*19*	
Total (throughput weighted)	31		3,938		

Table 13: Major gas pipelines carrying natural gas from Canada to the U.S. Mileage, diameter, and throughput information are drawn from the Canadian National Energy Board [195, 196] and sources listed in the table. The Trans Quebec & Maritimes and TransCanada Mainline pipelines (italics) are included for reference but omitted from the inventory since less than a quarter of their throughput is dedicated to the U.S. Counting these two pipeline systems would increase the cost estimate to $13 B.

Table 13 implies that the asset value of U.S.-serving Canadian gas pipelines exceeds that of analogous oil pipelines, since their weighted length and diameter are both longer. This comparison may seem surprising, since U.S. imports of Canadian oil are far more significant than of Canadian gas: net energy flow from Canada in the form of oil is approximately 3 times that of gas. However, gas pipelines must be larger-diameter and therefore more expensive for a given energy flow. In our inventory, U.S. gas transmission and gathering pipelines alone have over 5 times the asset value per energy flow as do U.S. oil pipelines. We would therefore expect the asset value of U.S.-serving Canadian gas pipelines to be at least $5/3 = 1.7$ times that of oil pipelines. Furthermore, Canadian gas pipelines are geographically more extensive than those for oil, originating further north in Alberta and British Columbia in the West, and extending offshore in the East. The total asset value of U.S.-serving Canadian gas pipelines matches these expectations, at 1.8 times the value of analogous oil pipelines:

$$\text{Cost}_{\text{Can. gas pipe}} = 3938 \text{ miles} \times 31 \text{ inches} \times \$75,000 \text{ /inch-mile} = \mathbf{\$9.2\ B}.$$

E. Oil and gas processing, storage, and non-pipeline transport

E.1. Processing – oil refineries

The 143 refineries in the U.S. (as of 2012) process far more oil than is produced domestically, since most petroleum imports (>80%) are in the form of crude oil that is locally refined [14]. Total refinery capacity in the U.S. is 17.3 M barrels per day [14], enough to process both domestic oil production (6.5 M bpd) and all imported crude oil (8.5 M bpd). (See Table 2.) As seen in Section C, oil refining is in fact an export industry for the U.S., with some imported crude re-exported after refining. In the most extreme case, over half of imported crude oil from Mexico is returned to Mexico as refined products [134].

While exports of refined products have grown as shale oil production expanded, U.S. per capita consumption of oil has remained nearly flat for decades, and the refining industry has met demand without new construction: no major greenfield[27] refineries have been built in the U.S. since 1977 [216]. Expansion of existing refineries has provided a small increase in total capacity (about 5% total increase from 2000-2012) [14, 38], and U.S. refineries operate at nearly 90% mean utilization, still higher in summer when demand peaks [217]. The lack of recent major projects makes cost estimation for new refineries difficult.

We collect information on projected or actual costs of 25 recent refinery projects from between 2008–2014, shown in Table 14 and Figure 20 (blue). Nearly all are U.S. capacity expansions, but the list includes one proposed U.S. greenfield refinery that was never built, and some projects in Canada and Mexico. We take the average cost of ∼$23,000 per BPD capacity as our metric for refinery cost, and the standard deviation of ∼40% as a measure of its uncertainty.[28]

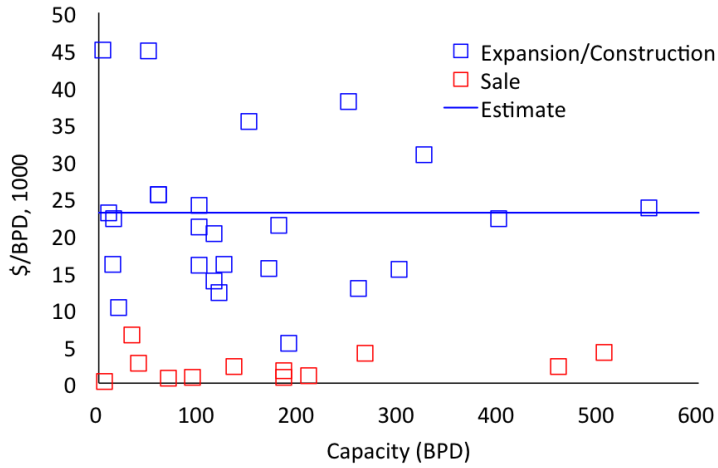

Figure 20: Cost per capacity of recent oil refinery expansion and construction projects (blue) and of recent sales (red), plotted against capacity. Blue line shows mean value used. Sales costs appear too low for use in infrastructure cost estimation. For sources see Tables 14 and 15.

The fact that the U.S. is a net exporter of refined petroleum products means that we need to weight any cost estimate to account for only that capacity required to refine fuels actually used within the U.S. In 2012, the U.S. refined 15.4 M bpd[29] of domestic and imported crude oil [217], and exported a net of 1.07 M bpd refined product, equivalent to 1 M bpd of input crude oil given a 7% processing gain (Table 2). If all exported refined products are derived from crude oil imports (reasonable since refineries are often located in import/export hubs), the U.S. share becomes $f_{\text{U.S.}} = (15.4 - 1)/15.4 = 0.94$[30] and export-adjusted refinery asset value is:

$$\text{Cost}_{refineries} \;=\; 17.3 \text{ M BPD capacity} \times \$23,000/\text{BPD} \times 0.94 \;=\; \mathbf{\$373\ B}. \tag{3}$$

[27] A greenfield facility is a newly constructed refinery that is not built adjacent, near or in place of an existing refinery, and that requires new infrastructure connections, storage, terminals and supporting structures [216].

[28] The estimate of $23,000 per BPD does not appear biased high by recent refinery additions designed to handle heavier oil from Canadian tar sands. For example, the BP Whiting tar sands upgrade cost (drawn from initial estimates) is < $23,000.

[29] The EIA refinery inputs of 15.37 M bpd [217] exceed domestic crude production + net crude imports of $6.50 + 8.46 = 15.0$ M bpd (Table 2). The difference could be explained by addition of NGL, renewables and oxygenates to refinery inputs.

[30] About 1/3 of U.S. product exports, ∼0.314 M bpd [38], are in fact NGL that likely does not pass through refineries. Accounting for this would raise the factor $f_{\text{U.S.}}$ to 0.96. Note that because we assume refinery costs and capacity factor are equal everywhere, it does not matter to costs whether imports of refined products are consumed in the U.S. or re-exported; the only relevant factor is the net export of products from refineries.

Project	Location	Capacity	Cost $M, nominal	$/BPD, 2012	Source
Rock River Resources	Green River, UT	10,000	230	23,000	[218]
PEMEX	Tula, Mexico	250,000	9,650	38,033	[219]
Arizona Clean Fuels Yuma	Yuma, AZ	150,000	5,000	35,322	[220, 221]
Hyperion	Union County, ND	400,000	9,000	24,633	[222–224]
Greenfield Refinery, Kitimat Clean	Kitimat, BC, Canada	550,000	13,000	23,289	[225]
Trenton Topping Refinery, Dakota Oil Processing	Trenton, ND	20,000	200	10,180	[226]
Newfoundland&Labrador Refinery Corp.	Placentia Bay, Newfoundland. Canada	300,000	4,600	15,333	[227]
Williston Refinery, Northwest Refining Inc.	Williston, ND	100,000	1,500	23,312	[228, 229]
Fort Motiva Refinery Expansion, Motiva (Shell, Saudi Aramco)	Port Arthur, TX	325,000	10,000	21,925	[230]
Delaware City Refinery, PBF Energy Partners	Delaware River, DE	190,000	1,000	5,358	[231]
McPherson Refinery Upgrade, NCRA	McPherson, KS	15,000	327	22,191	[232]
New Coker Unit, Total	Port Arthur, TX	50,000	2,200	44,790	[233]
Hydrocracker Unit, Valero	Port Arthur, TX	60,000	1,500	25,449	[234]
Hydrocracker Unit, Valero	St. Charles, LA	60,000	1,500	25,449	[234]
Tesoro SLC Refinery, Tesoro	Salt Lake City, UT	4,000	180	45,000	[235]
BP Whiting Plant	Whiting, IN	260,000	3,000	15,539	[236]
Garyville Refinery, Marathon	Garyville, LA	180,000	3,900	21,349	[237]
Come by Chance Refinery, Harvest Energy	Newfoundland, Canada	115,000	1,435	13,840	[238, 239]
Consumers Cooperative Refineries Ltd.	Regina, Sask., Canada	100,000	2,439	24,036	[240, 241]
Marathon, Detroit HOUP	Detroit, MI	115,000	2,200	20,119	[223]
BP, Husky JV. Toledo Refinery	Oregon, OH	170,000	2,500	15,466	[223]
COP/Encana JV, Borger	Roxana, IL	120,000	1,400	12,269	[223]
COP/Encana JV, Wood River Phase 1	Wood River, IL	125,000	1,900	15,985	[223]
COP/Encana JV, Wood River Phase 2	Wood River, IL	100,000	2,000	21,033	[223]
HollyFrontier	Salt Lake City, UT	14,000	225	16,071	[242, 243]
Average			22,952		
STDEV			9,773		

Table 14: Cost estimates from 24 recent proposed or completed refinery projects in the U.S., Canada, and Mexico. Most are capacity expansions but the list includes one new build, Hyperion in North Dakota, which was proposed and permitted but never built. (Construction permits expired in 2013.) All costs are given in 2012 dollars; we assume originally reported costs are in nominal dollars of the year of the report. Canadian costs are converted with the 2006 Federal Reserve exchange rate of 1.115 CAD to 1 USD [141]. We use the mean of these projects, ∼$23,000 / BPD, as our infrastructure value for oil refineries.

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Project	Location	Capacity	Cost $M, nominal	$/BPD	Source
PBF for Sunoco Inc	Toledo, OH	172000	400	2,327	[244]
PBF for Valero plant	Delaware City, DE	210000	220	1,048	[245, 246]
PBF for refinery	Paulsboro, NJ	185000	340	1,909	[244, 246]
BP sale of refinery to Tesoro	Carson, CA	266000	1,075	3,982	[247]
BP planned sale of refinery	Texas City, TX	460000	2,850	6,516	[248, 249]
Delta for ConocoPhillips	Monroe, LA	185000	280	1,514	[250]
Modular Oil Refinery Development	WY, CO, ND	40000	50	2,727	[251]
Somerset refinery	Somerset, KY	5500	60	11,105	[252, 253]
Sonoco	Philadelphia & Marcus Hook, PA	505000	4,100	8,265	[254]
Meraux refinery, sale by Murphy Oil to Valero	Meraux, LA	135000	300	2,262	[255]
Superior refinery, sale by Murphy Oil to Calumet Speciality partners	Superior, WI	33250	214	6,552	[255]
Tesoro sale to Par Petroleum	Kapolei, HI	94000	75	786	[256]
Alon acquisition of Bakersfield Refinery	Bakersfield,CA	70000	40	594	[257]

Table 15: Cost estimates from 13 recent refinery sales in the US, 2009–2013. All costs are given in 2012 dollars; we assume originally reported costs are in nominal dollars of the year of the report. Costs are uniformly low, likely because existing refineries are very old, past their service lifetime, and furthermore carry heavy liability burdens. For example, in the says of its Philadelphia refinery, Sunoco Inc. reportedly received only 20% of its appraised value [244, 248].

E.2. Processing – natural gas

Natural gas when it is first extracted at the well contains contaminants and impurities, including water, nitrogen, helium, acid gases, and non-methane hydrocarbons. If present at high concentrations, these impurities must be removed before gas can be safely delivered to high-pressure transmission pipelines as "pipeline quality" dry natural gas (essentially pure methane). Hydrocarbons such as ethane and butane can also, once purified, be sold as natural gas liquids. In 2012, about two thirds of raw natural gas was cleaned in midstream processing plants before entering transmission pipelines [15]. (Some processing also occurs upstream at the wellhead and downstream at storage facilities.) Recent years have seen a rapid buildup of U.S. natural gas processing infrastructure with increased production of shale gas, which tends to be particularly "wet" or rich in natural gas liquids and requires heavy processing.

Because a major usage of natural gas is for heating, natural gas demand experiences a strong seasonal cycle: U.S. usage in winter is nearly 70% higher than in summer [144]. Storage of natural gas is not sufficient to smooth out this demand fluctuation, so gas production itself varies seasonally. Processing plant capacity must be built to accommodate the wintertime peaks, leaving it underutilized in summer. The EIA inventories natural gas processing capacity every three years via a mandatory survey of all natural gas processing plants. The 2012 survey reported 525 plants with cumulative processing capacity of 64.3 billion cubic feet per day (bcfd), which cleaned a total volume of 44.7 bcfd of natural gas in 2012. [15]. That is, mean utilization of U.S. processing plants is only ∼65%. By contrast, oil demand has only small seasonal fluctuations, and oil refineries operate at ∼90% of capacity (Section E.1.)

We use the 2012 gas processing capacity value for this inventory but note that midstream infrastructure has continued to expand after 2012 as the shale gas revolution has driven steady increases in the the volume of natural gas processed in the U.S. The EIA releases estimates of processing plant capacity only intermittently, but both processed volume and plant capacity rose by ∼15% in the two years from 2012 to 2014.

We estimate the construction costs for natural gas processing plants using both industry reports and collected information on individual processing plant construction projects. ICF conducts regular studies to project investment in U.S. natural gas (and oil) infrastructure, commissioned by the the Interstate Natural Gas Association of America (INGAA). We consider estimates of national-average plant costs in ICF reports from 2009, 2011, 2014, and 2016 [155–158, 188], and compare with costs of individual projects between 2001–2007 gathered from informal sources. These estimates are shown in Figure 21 and data is described in Table 16. Costs in $ per capacity show reasonable agreement between sources and no clear trend either over time or with plant capacity. We take an approximately central value of $700 per thousand cubic foot per day, or $700 M per bcfd.

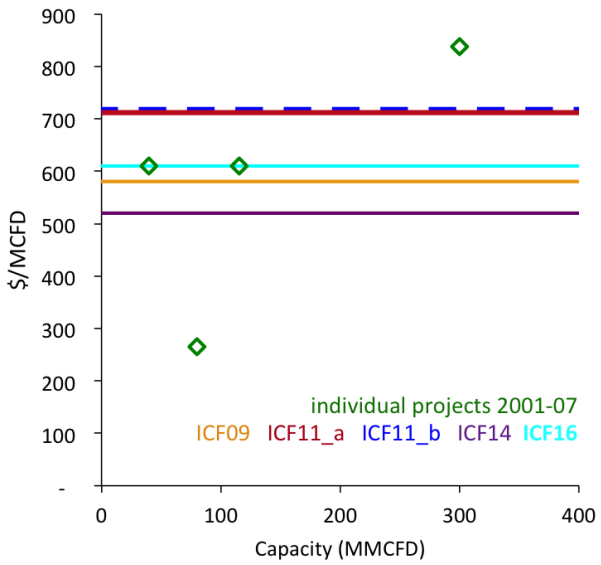

Figure 21: Scatter plot of estimated unit construction cost for processing plants ($ per MCFD, 2012 dollars) against capacity (MMCFD). Sources are described in Table 16. We adopt a value of $700/MCFD, effectively that of the 2011 ICF report.

Lastly, we apply an adjustment to account for those foreign facilities that process natural gas imported into the U.S. The net import of natural gas is 1.5 TCF/yr or 6% of domestic production (see Table 2), and we assume that foreign processing plants have the same utilization rate as those in the U.S. The total asset value of U.S. natural gas processing plants in 2012 is then:

$$\text{Cost}_{ng\ process.} \;=\; \$700\text{ M / bcfd} \times 64.3\text{ bcfd} \times 1.06 \;=\; \mathbf{\$48\ B}.$$

Project name/source	Year	Capacity	Project value	Unit cost	Source
		MMCFD	$M, nominal	$/MCFD	
Marham Texas	2001	300	200	837	[258]
Energy Transfer Partners LP – Johnson County, TX	2007	115	65	611	[259]
Hilland Partners	2008	40	23	609	[162]
PVR Midstream	2008	80	20	265	[162]
ICF4, 2009-2030 projection	2009	24100	13200	580	[156]
ICF1, a, 2011-2020 projection	2011	18100	12400	712	[155]
ICF1, b, 2011-2035 projection	2011	32500	22400	716	[155]
ICF2, projection through 2035	2014			520	[158]
ICF5, projection through 2035	2016			610	[188]
Chosen estimate				*700*	

Table 16: Collected cost of natural gas processing plants construction. This is the source table for Figure 21. ICF values are national estimates derived from reports on projected national infrastructure spending: 2009 [ICF4; 156], 2011 [ICF1; 155], 2014 [ICF2; 157, 158], and 2016 [ICF5; 188]. Cost estimates of individual processing plant projects from 2001–2007 are collected from news reports and press releases: [162, 258, 259]. *ICF1,a* and *ICF1,b* are the 2011-2020 and 2011-2035 baseline projection of added processing plant capacity and estimated expenditure, both from the same report *ICF1*.

E.3. Transport – oil

E.3.1. Oil tankers

Imported oil, as discussed in Section C.1, represents a substantial fraction of total U.S. energy usage in 2012, and all imports other than Canadian oil (which moves by pipeline) are carried by sea in oil tankers. Tankers brought 6.1 million barrels per day of crude oil to the U.S. in 2012, largely delivered at Gulf of Mexico ports and processed at nearby refineries [260].[31] Tankers thus carry over 70% (6.1/8.5) of U.S. imported crude, and we would expect their asset value would similarly exceed the $5B value of the Canadian pipelines that carry the remainder of oil imports.

Because the oil trade is global, it is not possible to distinguish a subset of tankers dedicated to serving the U.S. market. We can instead estimate a U.S.-related asset value by scaling global totals, because tankers worldwide are similar in characteristics and costs [16]. That is, we estimate the total cost of all oil tankers, and then adjust by the 2012 U.S. share of the global seaborne oil trade.

The oil tankers used worldwide for crude oil transport are classified into four types according to their volume carried (capacity): Panamax, Aframax, Suezmax, and Very Large Crude Carrier (VLCC), increasing in size from less than 80,000 deadweight tons (DWT) to greater than 200,000 DWT. [32] Many organizations issue reports on counts and cost estimates for these four tanker types. We take the 2012 values in the Clarkson Research 2015 Oil & Tanker Trades Outlook [16], but compare to other sources as validation. Table 17 and Figure 22 show costs and counts reported by 9 sources between 2008–2015, generally from global trade organizations including the United National Conference on Trade and Development. All are generally in good agreement. Tanker costs do decline from 2008–2012 for all classes but are fairly constant since then. Using the Clarkson values yields a total global asset value for tankers in 2012 of $142 B. These tankers serve the global crude oil seaborne trade, reported by Clarkson Research as 38.2 million bpd in 2012 [16], equivalent to nearly half of global oil production.[33]

[31] We estimate these tanker deliveries by subtracting Canadian imports from total U.S. imports, using the EIA data series of crude oil imports by country [37]: 8.53 M bpd total - 2.43 M bpd from Canada = 6.10 M bpd by tanker. This result is consistent with reported 2012 U.S. seaborne trade flow in the 2015 Oil & Tanker Trades Outlook published by Clarkson Research, a leading maritime transport consultancy [16].

[32] The definitions of tanker types are slightly inconsistent across sources. We give the definitions of the 2012 UNCTAD Review of Maritime Transport [261], but note that definitions can vary in diffrent reports. For example, the Suezmax is defined as 125–199,999 DWT in 2012 [261] and as 100–160,000 DWT in 2013 [262].

[33] Global production in 2012 is 76M bpd according to the EIA Monthly Energy Review [36, Table 11.1b], although the 2013 BP Statistical Review of World Energy reports a slightly higher 86M bpd [263].

Year	Number of tanker. $M/tanker								Source
	Panamax		Aframax		Suezmax		VLCC/ULCC		
2008		$63		$74		$94		$63	McQuilling1
2011		$45				$65		$03	UNCTAD
2012	413	$40	913	$48	469	$56	612	$91	Clarkson
2012	84	$37	653	$47	432	$56	561	$89	McQuilling2*
2013	414	$39	904	$46	492	$54	620	$87	Clarkson
2013	94	$35	666	$44	472	$55	610	$86	McQuilling2*
2013	417		908		492		623		Jeffrey
2014	412	$44	893	$52	489	$62	633	$94	Clarkson
2015		$44		$51		$62		$92	Clarkson
Global $B									$142

Table 17: Collected data on oil tanker newbuild cost ($ million, 2012 dollars) and number count by type, 2008-2015. Highlighted values are those we take as our cost estimate. Number counts from Mcquilling2 are quoted as "Averageding inventory," and are considerably lower than other sources for the lower-volume Panamax and Aframax tankers. Sources: McQuilling1: "McQuilling Outlook 2008" [264], UNCTAD: "UN Review of Maritime Transport 2012" [261], Jeffrey: [265], Clarkson: "Clarkson Research Oil & Tanker Trades Outlook 2015" [16], McQuilling2: "McQuilling Services Outlook Scorecard 2013" [266].

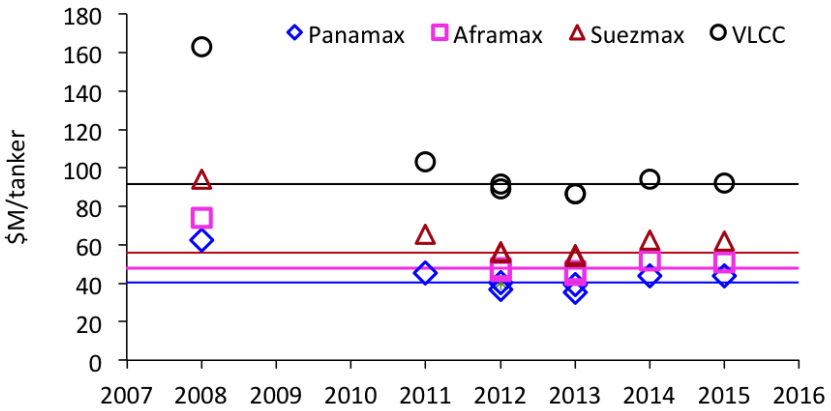

Figure 22: Collected estimates of oil tanker newbuild costs from all sources shown in Table 17, sorted by year 2008–2015. Costs for all tanker classes drop from 2008–2012 but are relatively flat since. We use the 2012 values from Clarkson [16], the higher of the two 2012 estimates shown here.

To determine the U.S. share of global seaborne oil trade, we evaluate the amount of crude oil carried to the U.S. by tanker that serves domestic consumption. As discussed previously, the U.S. is a net exporter of refined products, meaning that some portion of imported crude is re-exported after being refined. As before, we make the assumption that all refined-product exports are derived from imported crude oil, but we differentiate the tanker-carried trade to and from Gulf refineries from Canadian trade carried in pipelines. The net Gulf export of refined products is 1.24 M bpd[34]; with a processing gain of ∼7% this translates to 1.2 M bpd tanker-borne crude that is re-exported as refined product. That is, while the U.S. takes in 6.1 M bpd of tanker-carried crude oil in 2012, only 6.1 - 1.2 = 4.9 M bpd serves the domestic market. The share of the global seaborne oil trade that is intended for U.S. consumption is then 4.9/38.2 = 13%, and total U.S.-related tanker asset value is:

$$\text{Cost}_{tankers} = \$142 \text{ B} \times 0.13 = \mathbf{\$18\ B}.$$

[34]Total net product exports are 1.07 M bpd, but to evaluate the seaborne component only we must subtract trade with Canada. We therefore add a 0.17 M bpd of net imports from Canada; see Table 2.

E.3.2. Oil tank cars

The rapid rise of U.S. shale oil production has placed new demands on the oil transport system. Shale plays in the Midwest (e.g. the Bakken in N. Dakota and Montana) are not well-connected to pipeline networks at all, and production from shale plays in traditional oil areas (e.g. the Barnett and Eagle Ford in Texas) quickly exceeded pipeline takeaway capacity. Already by 2011, pipeline bottlenecks producing gluts of oil supply in Cushing, OK, were large enough to depress local oil prices [267]. Growth in Canadian oil production also outpaced pipeline expansion and depressed prices [268]. Both factors drove a boom in transport of oil by rail, which rose 16-fold between 2010 and 2014. By 2012, rail carried 0.81 M bpd of crude oil, over 12% of domestic production [269]. (Canadian rail shipments of oil were negligible in 2012 but have grown since, bringing heavy oil sands crude to refineries in the U.S. Midwest and Gulf regions [268, 270].) The boom in rail transport involved some construction of new rail hubs, e.g. to the Bakken [268], but we do not attempt to account for these here. We also do not attempt to tally any tank cars used for refined petroleum products, as these are not typically assessed separately in industry reports and are difficult to quantify. Instead we tally only the tank cars in which crude oil is shipped.

Crude oil tank cars are appropriate for inclusion in the inventory as they are expensive, long-lived (∼35-year lifetime [271]), and difficult to repurpose for other uses. Oil tank cars fall in a broad category of transport for Class 3 flammable liquids, which include both crude oil and ethanol as well as refined gasoline and other chemicals. Nearly all such cars are dedicated to single commodities only [272]. While re-use of oil tank cars for another commodity is not impossible, it is unclear that any alternative purpose for oil tank cars would exist: in 2013, over 1/3 of all U.S. Class 3 flammable liquid tank cars are used for crude oil [272], and transport of ethanol has been fairly flat for the last decade [269, 273].

The growth in oil tank car numbers is extensively documented because of safety concerns about transporting crude oil in old-style non-jacketed cars. Crashes of oil trains, including the 2013 Lac-Mégantic rail disaster that killed 47 people, led to proposals for new standards to minimize explosion risks and multiple studies estimating the numbers of older tank cars that would need to be replaced. These include U.S. Congressional and Department of Transportation reports [272, 274, 275], industry studies [276], and reviews of proposed regulations commissioned by manufacturing groups [277]. None give values for our benchmark year of 2012 but several give timeseries that begin in 2013 or 2014. (We assume cars active in 2013 were under construction in 2012 and appropriate to include in this inventory.) Most estimates are in the range of 40,000 tank cars: for example, a report by the Brattle Group for the Railway Supply Institute Committee on Tank Cars [277] counts 43,732 at the end of 2013, and the IHS special report "Crude by rail" [276] counts 42,550 in 2014. (A 2016 Dept. of Transportation report [272] is an outlier, suggesting only ∼27,000 crude oil tank cars in 2013.) Growth in numbers is also rapid during this time period: both the Brattle Group and Congressional reports project a near-doubling by the end of 2015. For the purposes of this inventory, we use the Brattle Group tank car count of 43,732 as of 2013.

The cost of tank cars depends on their type and safety standards, but over 90% of crude tank cars in 2012 are older, cheaper, non-jacketed types (DOT-111 and CPC-1232) [272]. We can place a lower bound on cost from sales averaged over all railcar types. Sales figures from the Greenbrier Companies, Inc., a leading manufacturer for rail cars, imply a mean sales price in 2013 of $106,000 per railcar inclusive of cheaper types such as flatcars and boxcars [278]. RBN Energy reports a range of $130,000 to $150,000 for new crude oil tank cars in 2014, with the higher value for cars complying with new PHMSA safety standards and the lower value more typical of the 2012 U.S. fleet [271]. We take $130,000/car as a reasonable estimated cost, and multiply by the estimated number of active rail cars to derive a total value of:

$$\text{Cost}_{tank\ car} \;=\; \$130{,}000/\text{car} \times 43{,}732 \text{ cars} \;=\; \mathbf{\$5.7\ B}.$$

Comparing this asset value with that for oil tankers in the previous Section E.3.1 suggests that it is broadly reasonable. Our numbers suggest that the capital cost of the vehicles used in transporting a given flow of oil by rail is about twice that for those used in transporting it by tanker: $19B/4.9 M bpd ∼ $4K / bpd for seaborne transport, vs. $5.7B/0.81 M bpd = $7K / bpd for rail.

E.4. Transport – liquid natural gas (LNG)

Liquid natural gas (LNG) played only a minor role in the U.S. energy system in 2012. (See Table 2.) The most cost-effective way to transport natural gas is as pressurized gas in pipelines, and the overwhelming bulk of U.S. imports arrive by pipeline from Canada. However, the only viable means of moving natural gas across oceans is as LNG. The process is necessarily expensive as it requires cooling the gas to approximately -162 C (-260 F) until it liquifies, and transport in a specialized insulated ship. Safety precautions add to the cost, since leaks from LNG tanks can lead to catastrophic explosions.

Just before the shale-gas revolution, the U.S. saw a burst of investment in infrastructure for LNG import, driven by projections that rising U.S. demand would not be met by domestic and Canadian supply. The 11 U.S. LNG import terminals existing in 2012 were capable of handling over 25% of U.S. consumption, with most of this capacity constructed during 2008–2012 (and the remainder dating to the 1980s) [279, 280]. The advent of cheap domestic shale gas means that this infrastructure now sits largely unused. Actual net LNG imports in 2012 constitute less than 0.6% of U.S. consumption. U.S. investment in LNG facilities has now shifted to export terminals to allow shipping domestic natural gas to higher-priced overseas markets.

For this inventory, we tally the value of the gas carriers and terminals that serve U.S. LNG imports. We do not consider foreign liquefaction facilities. LNG is typically regasified in the receiving terminal;[35] once in gaseous form, the gas is carried within the United States in the pipelines inventoried in Section D.

E.4.1. Natural gas carriers.

We evaluate the asset value of U.S.-related natural gas carriers based on estimates of 1) new-build cost per capacity, 2) global carrier capacity, and 3) the estimated U.S. share of the global LNG carrier fleet.

We take our capacity estimate from "Clarkson's Gas Carrier Register 2011" [284] from Clarkson Research, a leading maritime transport data consultant, which gives a global vessel count of 362 at the end of 2011 with a mean capacity of 143,000 cbm, for a cumulative capacity of 51.9 million cbm. This estimate is consistent with a series of annual reports from the International Gas Union (IGU), which report capacity in 2012–2016 of 54, 54, 55, and 63 million cbm[36] [280–283].

We use a single cost estimate despite the fact that LNG vessels vary in both their propulsion technologies and container systems. All gas carriers are powered by the LNG they carry, but propulsion tecnologies have evolved from gas-fired steam turbines to internal combustion engines that burn either LNG or diesel, known as dual-fuel or tri-fuel diesel electric (DFDE/TFDE) [280, 281]. For container systems, most gas carriers use traditional spherical Moss-type tanks, which are self-supporting, but 25% of the global fleet now uses flexible membrane tanks in which the hull of the ship bears the load [280–283]. Information on capacity and costs of the different vessel types is limited, but the IGU notes that costs per capacity have remained within a narrow range for all gas carrier types, from \$1100–1800/cbm (in 2016 dollars) [280]. Estimates sourced from Clarkson Research range from \$1250-\$1360/cbm [285].[37] We take an approximate median value across all vessel types of \$1,300/cbm (2012 dollars) drawn from a series of IGU reports [280, 283].

Lastly, we estimate the U.S. share of global LNG trade using the British Petroleum Statistical Review of World Energy June 2013 release of 2012 data [263], with U.S. and global LNG import volumes at 0.174 and 11.6 TCF/year.[38] The U.S. share of global LNG transport is then (0.174/11.6) = 2%, meaning that total gas carrier costs related to the U.S. trade are:

$$\text{Cost}_{gas\ carrier} \;=\; \$1300/\text{cbm} \times 51.9\ \text{M cbm} \times .02 \;=\; \$\mathbf{1.0\ B}.$$

[35] Reports on LNG terminals generally note that projects include gasification facilities, and International Gas Union reports generally consider regasification as part of LNG receiving terminals [280–283].

[36] The 2013 IGU (giving 2012 volume) reports contain a typo and states a value of 54 "bcm" (for 362 vessels); all other reports give units as millions of cubic meters [280–283]. All IGU values exclude vessels under 18,000 cbm.

[37] These estimates appear in presentation slides by Jeffrey LLC, who show the cost per vessel remaining steady over 2001–2013 at ∼\$200 million (in 2013 dollars), with vessel size stated as 147/160K cbm.

[38] Values are in gas-phase volume. The BP estimate for the U.S. is consistent with the EIA value [40] in Table 2.

E.4.2. LNG terminals

The Federal Energy Regulatory Commission (FERC) periodically surveys LNG terminals in the U.S. and recorded 11 import terminals in 2012 with a total capacity of 18.5 billion cubic feet per day (bcfd) or 6.8 TCF/year[39]. This capacity far exceeds actual imports of LNG, which are 0.174 TCF/year. That is, the capacity factor for these terminals is (.174/6.8) = 2.5%. U.S. LNG import infrastructure is severely overbuilt given existing utilization.

We estimate the cost per capacity of these terminals based on collected news and trade organization articles on recent international LNG terminal projects ([288–291]; see Table 18 for details), and from annual reports by the International Gas Union (IGU) from 2014–2016. The IGU lists individual LNG import terminals by country, along with annual generic construction cost estimates from 2005 [280, 282, 283].[40] All cost estimates are shown in Figure 23 IGU cost estimates are relatively flat before 2010 and then rise steeply (left panel). In 2012, IGU costs are ∼$1 B/bcfd, but rise to ∼$2B/bcfd by 2017. (IGU 2012 costs are $1.055 B and $1.332 B for terminals with and without storage.) Collected project costs have a slightly lower mean cost than IGU estimates, $0.75 B per bcfd in 2012 dollars, but with wide variation. They show no clear trend with capacity (right panel).

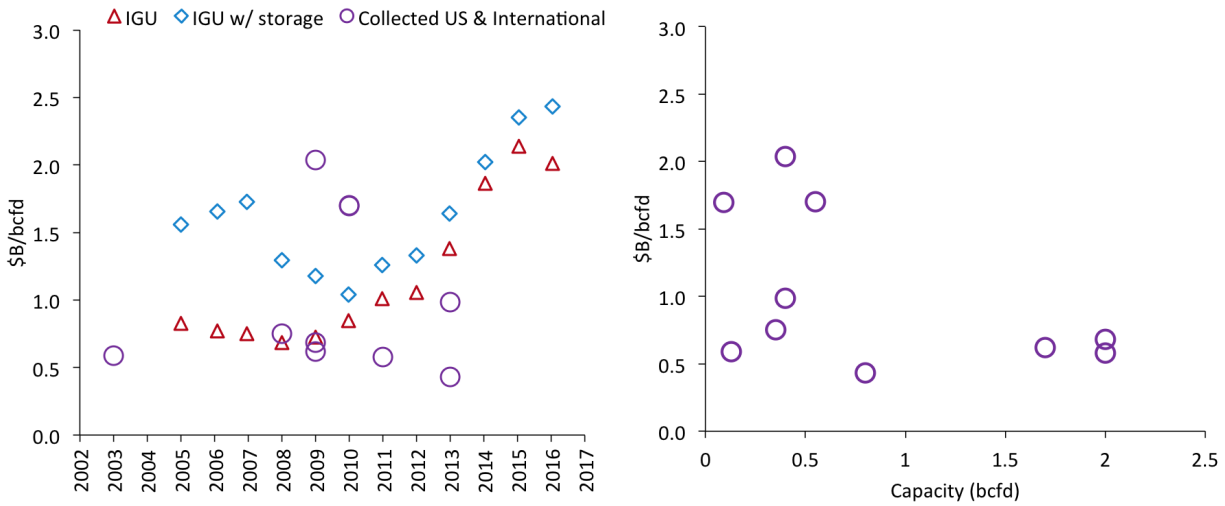

Figure 23: Construction costs for LNG terminals ($B/bcfd, 2012 dollars) plotted against time **(left)** and against plant capacity **(right)**. Purple circles show the collected project costs of Table 18; red triangles and blue diamonds show cost estimates by the IGU for terminals with and without storage, extracted by plot digitizer from figures shown in IGU reports [280, 282, 283, 292]. The IGU reports capacity in thousand tons per year (mtpa) rather than cubic feet per day; we use a conversion factor of 0.13 bcfd/mtpa as recommended by the Canada National Energy Board [293]. Costs show no clear dependence of cost with capacity (right), though larger projects may be less expensive. (For context, U.S. mean LNG terminal capacity is 1.7 bcfd.) Costs rise after 2010. We adopt for this inventory a value of $1 B/bcfd.

We adopt for this inventory a value for LNG terminal costs of $1 B/bcfd, similar to IGU estimates for the benchmark year of 2012. Total asset value is then:

$$\text{Cost}_{LNG\ terminal} = \$1\ \text{B/bcfd} \times 18.5\ \text{bcfd} = \mathbf{\$18.5\ B}.$$

[39]The FERC report is a one page list of existing, proposed, abandoned, and in-construction terminal projects in North America. The 2012 report lists 11 terminals operating in the U.S. [279], and the 2018 report clearly identifies these particular 11 terminals as import rather than export terminals [286, 287].

[40]The IGU reports list the same 11 U.S. terminals as does FERC, and give their capacity as 132 mtpa or 17 bcfd, 7% smaller than total capacity in the FERC survey [279]. Over half of the terminals, making up three quarters of total capacity, are consistent across both sources. The difference stems from a few of the smaller terminals, and may be an artifact of our unit conversion. The FERC describe capacity in bcfd, a volume measure, but the IGU uses mtpa (million tonnes per annum), a mass measure, and conversion factors vary depending on reference pressure and temperature.

Project/location	Owner	Proj. value ($B, nominal)	Cap (bcfd)	Cost/capacity ($B/bcfd, 2012)	Source	Year
Sabine Pass, TX, U.S.	ExxonMobil, Qatar Petroleum, ConocoPhillips	1.1	2	0.55	[288]	2009
South Hook Term., Milford Haven, Wales, UK	ExxonMobil, Qatar Petroleum	1.3	2	0.65	[288]	2009
Grain Terminal , Kent, UK	Grain LNG Ltd.	1	1.7	0.59	[288]	2009
Fujian Terminal, Fujian Province, China	CNOOC/ Fujian LNG CO. Ltd.	0.25	0.35	0.71	[288]	2009
GNL Quintero Terminal , Quintero Bay, Chile	GNL Quintero S.A.	0.78	0.4	1.9	[288]	2009
AES LNG Terminal , Dominican Republic	AES Corp	0.07	0.13	0.56	[288]	2009
EcoElectrica Terminal , Puerto Rico	EcoElectrica	0.15	0.09	1.6	[288]	2009
Elba Island Upgrade Phase III, GA, U.S.	Southern LNG	0.9	0.55	1.6	[291]	2010
Neptune Deepwater, MA, U.S.	Neptune LNG	0.4	0.4	1	[290]	2013
Northeast Gateway, MA, U.S.	Excelerate Energy	0.35	0.8	0.44	[290]	2013
Total / Avg.		6.3	8.4	**0.74**		

Table 18: Collected costs of international newbuild LNG terminals, and capacity weighted average cost. This is the source table for Figure 23.

E.5. Storage – oil

Fossil fuels have the advantageous property that they can be readily stored to smooth out disparities in supply and demand, unlike electricity, where production and sales must equal at every moment. We tally the value of three types of facilities used to store crude oil & petroleum products: bulk terminals, crude tank farms, and the underground caverns of the Strategic Petroleum Reserve (SPR). These combined facilities stored about 2 B barrels in 2012, with a third in long-term storage in the SPR and the remaining 1.3 B barrels turning over more rapidly (Table 19). The EIA also reports storage at refinery facilities and the volume of crude oil and refined products in transit (largely in pipelines); these contribute an additional 0.8 B barrels, for a total of ∼2.1 B barrels of short-term storage, equivalent to about four months of usage. (Monthly consumption of petroleum products is about 0.56 B barrels; see Table 2.) These values imply that crude oil in the U.S. takes ∼4 months to move from wellhead or import terminal to end users.

To estimate total asset value, rather than counting individual facilities we use EIA surveyed total U.S. storage capacity [17] and construct estimates of national mean construction cost per capacity for each type of storage. Cost estimates are drawn from a variety of sources, including collected industry and news reports describing individual projects. Results are summarized in Table 19. Bulk terminals make up a bit less than half the inventoried oil storage capacity, but more than 90% of the total asset value of **$126 B**.

Types	Capacity M bbl	Cost per capacity $/bbl	Subtotal $B
Bulk terminals	943	125.0	117.9
Strategic Petroleum Reserve	727	3.5	2.5
Crude tank farms	341	16.0	5.5
Refineries	*625*		
Oil pipelines	*83*		
Product pipelines	*88*		
Total	2725		
Total, excl. refineries & pipe.	**2012**		**126**

Table 19: Summary of oil storage capacity and cost. Capacity is taken from the 2012 EIA report (fall release, published in September) *Working and Net Available Shell Storage Capacity* [17]. Costs are estimated from a variety of sources, including a report on midstream oil and gas infrastructure prepared by ICF [158], a Dept. of Energy factsheet [294], and collected industry sources listed in Table 20.

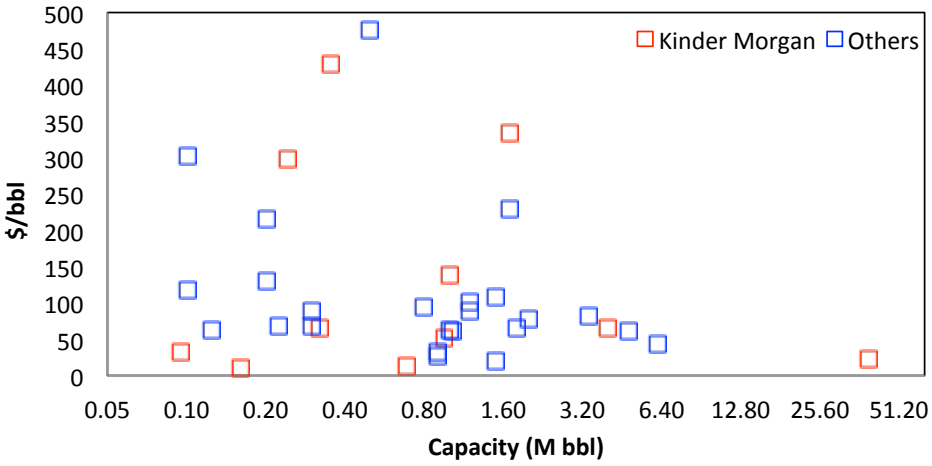

Figure 24: Collected estimates of unit construction cost for bulk terminals used for oil and petroleum product storage ($ per barrel, adjusted to 2012 dollars), plotted against capacity (million barrel). Table 20 provides details of individual estimates. Thecollection includes not only newbuilds but also expansion and aquisition projects whose costs tend to be lower. Mean cost across all datapoints here is $60/bbl; mean cost for newbuilds is ∼$100/bbl. Red color denotes cost estimates from Kinder Morgan, which in aggregate may also be biased low.

Bulk terminals. In the US, there are ∼1400 bulk terminals [295] owned and operated by wholesalers distributing crude oil and petroleum products. To estimate their costs, we collected more than 30 records of acquisition deals and expansion or newbuild projects from company reports and news articles. (Figure 24 and Table 20 show data and sources.) Costs show wide variation, including systematic differences by project type, with newbuilds on average the most expensive. Of the collected estimates, we suspect that those from Kinder Morgan are biased low because many of these describe individual storage and connection facilities contained within a larger terminal project whose common costs are not included. Mean cost per capacity for all newbuilds in our collected estimates is ∼$100/bbl; when Kinder Morgan projects are excluded this value approaches $200/bbl. We take a conservative cost estimate of $125 per barrel.

Crude tank farms. We base our cost estimate on two sources, a report on midstream oil and gas infrastructure prepared by ICF for the Interstate Natural Gas Association of America [158] and a Dept. of Energy factsheet on oil storage [294]. These source provided consistent cost estimates: the ICF report lists costs for crude oil storage tanks $15/bbl and the DOE factsheet as $15–18/bbl (in 2012 dollars). We take a midpoint value of $16 per barrel.

SPR. By agreement with the International Energy Agency (IEA), the U.S. must store the equivalent of 90 days of imported oil for "import protection", to substitute for imports in case of emergencies that curtail international shipments [296]. The Strategic Petroleum Reserve consists of four underground sites within a government complex along the Gulf Coast in Texas and Louisiana where oil is stored in man-made caverns within salt deposits. In order of total capacity, these are Bryan Mound, West Hackberry, Big Hill, and Bayou Choctaw. Each contains between 6 and 22 caverns, allowing storage of multiple distinct types of crude [294]. Because withdrawls from the SPR are made infrequently, in practice oil can remain in the SPR for years. The DOE factsheet on oil storage [294] estimates a capital cost of $3.50 per barrel for stockpiling oil in salt caverns, implying an upfront cost of $2.5 billion for the 727 M barrel SPR. The same source does give a contradictory estimate of ∼$5 billion total investment in SPR facilities. We take the more conservative estimate of $3.5 per barrel.

Project/owner	Type	Location	Proj. value	Capacity	Cost/cap	Compl. date	Type of petroleum product	Source
			$ M nominal	MM BBL	$/bbl nominal			
Collected News, Media Release, and Trade Publications								
Global Partners	A	NY	47.5	0.95	50	2010	Petrol, kerosene, diesel, kerosene, home heating oil	[297]
Buckeye Partners	A	Perth Amboy, NJ	260	4	65	2012	Liquid petro. prod.	[298]
Buckeye Partners LP	A	U.S. East Coast	850	39	22	2013	Crude oil, refined petro. prod.	[299]
Blackwater Midstream	A	Brunswick, GA	1.8	0.16	11	2010	Liquid fertiliser, fuel oil, chemicals	[297]
Center Point Terminals	A	WV	9.1	0.68	13	2010	Residual fuels, light oils	[297]
Embridge	E	Alberta, CA	150	0.35	429	2012	Bitumen	[300]
Westway Terminals	N	Port of Grays Harbor, WA	20	0.32	63	2009	Methanol	[297]
Florida Fuel Connection	N	East Feliciana Parish, LA	75	0.24	313	2015	Gasoline, diesel, aviation fuel	[301]
Pin Oak Terminals	N	Baptist Parish, LA	600	1.696	354	2017	Refined prod. , biofuels	[302]
US Navy	N	Point Loma Naval Base, CA	140	1.0	140	2013	Jet, marine diesel	[297]
Harbor Fuel	N	Nantucket, MA	3	0.095	32	2009	Petrol, diesel, aviation fuel, jet fuel, home heating oil, ULSD, propane	[297]
Kinder Morgan Reported Terminal Projects								
Gateway Project	N*	Carteret, NJ	62.1	1	62	2011	Distillates	[303]
Carteret E, KM	E	Carteret, NJ	60.5	1.035	58	2011	Gasoline/Diesel	[304]
Carteret API Swing Tanks	N*	Carteret, NJ	28.5	0.3	95	2016	Gasoline	[305]
Deeprock	A	Cushing, OK	24.7	0.9	27	2011	Crude	[303]
Pony Express (Deeprock JV)	E	Cushing, OK	30.6	1.5	20	2014	Crude	[305]
State Class Tankers	A*	Edmonton, AB	412.5	1.7	243	2017	Crude/Products	[305]
Edmonton Tank E Phase I	E	Edmonton, AB	290.4	3.4	85	2014	Crude	[305]
Edmonton Tank E Phase II	E	Edmonton, AB	111.2	1.2	93	2014	Crude	[305]
Alberta Crude Terminal (Keyera JV)	N	Edmonton, AB	31.2	0.1	312	2014	Crude	[305]
Edmonton Tank Farm Development	N	Edmonton, AB	309	4.8	64	2017	Crude	[305]
Edmonton Rail Terminal (Imperial JV)	N	Edmonton, AB	248.8	0.5	498	2015	Crude	[305]
Galena Park Blend Tankage	N*	Galena Park, Pasadena, TX	12.5	0.1	125	2016	Refined Petroleum	[305]
Galena Park Tank Project	E*	Galena Park, Pasadena, TX	123.8	1.2	103	2014	Refined Products	[305]
Splitter Project	N	Galena Park, Pasadena, TX	75.8	0.8	95	2013	Refined Petroleum	[306]
Pit 9 Pasadena Tank Project	N*	Galena Park, Pasadena, TX	21.2	0.3	71	2016	Refined Petroleum	[305]
Houston Export Terminal	N	Houston, TX	172	1.5	115	2017	Blendstock	[305]
GreensPort Crude by Rail (KWX JV)	N*	Houston, TX	44.3	0.2	222	2014	Crude	[305]
Greensport Crude By Rail	N*	Houston, TX	26.4	0.2	132	2013	Crude/Condensate	[306]
BOSTCO Phase 1	N*	La Porte, TX	273.9	6.2	44	2014	Resid/VGO/Distillates	[305]
BOSTCO Phase 2	N*	La Porte, TX	30.7	0.9	34	2014	ULSD	[305]
GP/Pasadena Phase IV E	E	Galena Park, Pasadena, TX	113.7	1.8	63	2010	Gasoline/Diesel	[304]
GPTank -6 Tanks	N*	Pasadena, TX	7.5	0.125	60	2010	Gasoline/Diesel	[304]
Pit 11 Development	N*	Pasadena, TX	165.4	2	83	2017	Refined Products	[305]
Vancouver Wharves Term.	E	Vancouver, Canada	14.3	0.225	64	2009	Diesel	[304]
Total			4,847.4	80.4	60			
Total (newbuild only)			2,347.3	22.4	105			
Total (newbuild, no Kinder Morgan)			838.0	4.4	193			

Table 20: Collected data on construction cost for petroleum bulk terminals. Project type A/N/E stands for Acquisition, Newbuild, and Expansion. *Some Kinder Morgan projects are listed twice in their investor news report, and we pick the most recent project estimate

E.6. Storage – natural gas

Natural gas, unlike oil, is not generally stored in above-ground tanks, which are cost-prohibitive for gases, whose low density means that storage volumes must be large. Natural gas is instead stored in more cost-effective underground facilities. The EIA regularly assesses U.S. gas storage capacity, and reported as of 2013 a total of 414 natural gas storage sites, with large numbers in Pennsylvania (51), Michigan (45), and Texas (37). Total storage capacity across all sites is 9 trillion cubic feet (TCF) [307], but about half of this storage volume cannot effectively be used, as it must be left filled with "base gas" or "cushion gas"

to maintain adequate pressure and deliverability rates for withdrawal [18]. Subtracting this "permanent inventory" leaves a total usable volume of 4.5 TCF for natural gas storage and withdrawal, equivalent to a bit over two months of U.S. usage (Table 2). For context, a volume of 4.5 TCF is equivalent to 750 M barrels, less than half of the total U.S. oil storage volume

Underground gas storage facilities can be classed into three types: depleted oil and gas reservoirs, depleted aquifers, and salt caverns. The EIA data series *Underground Natural Gas Storage Capacity* lists capacity by type, showing about 80% in depleted reservoirs and 10% each in depleted aquifers and salt caverns [18]. The three types of underground storage differ in characteristics such as working gas capacity, shrinkage factor, geographical location, and deliverability. In general, salt caverns have high deliverability and injection capabilities and are mainly used for short-term deliverability (within a day), while depleted reservoirs and aquifers are used to buffer against longer-term (seasonal) variations in demand, with gas added in the summer and withdrawn in the winter.

Costs for these different underground facilities are relatively similar, unlike the case for oil, whose storage options are radically different. (For oil, capital costs for storage in aboveground bulk terminals are over 35 times those for the underground Strategic Petroleum Reserve.) We derive cost estimates from industry reports by or prepared for the National Energy Technology Laboratory (NETL) [308], the Federal Energy Regulatory Commission (FERC) [309], and the Interstate Natural Gas Association of America (INGAA) [155, 156, 158]. These sources are broadly consistent, agreeing on a factor of two spread between facility types, with depleted reservoirs the lowest-cost option, and on a general trend of costs rising over time (Figure 25). We assume \$10, \$15 and \$18 per thousand cubic feet (MCF), respectively, for depleted reservoirs, salt caverns, and aquifers, yielding a total asset value of **\$55 B**. Results are summarized in Table 21.

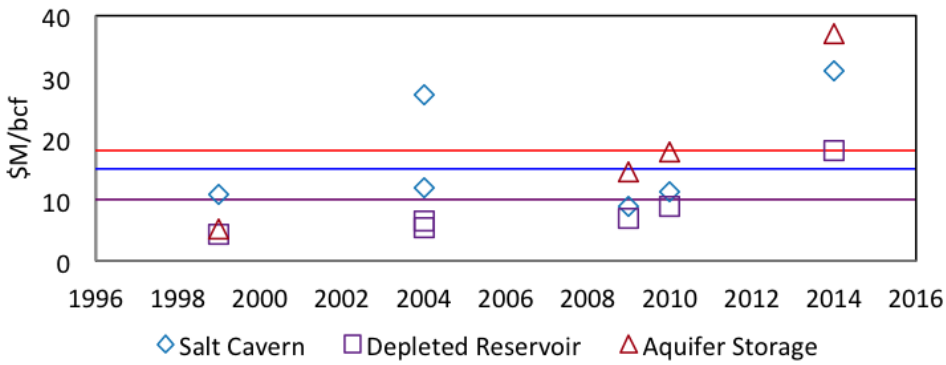

Figure 25: Scatter plot of unit construction cost over time for various types of natural gas storage (\$ billion per BCF capacity, 2012 dollars, adjusted for inflation). Symbols show estimates from reports from NETL [308], FERC [309], and INGAA [155, 156, 158]; and solid lines show assumptions used in this work. Since costs show a general upward trend with time, we take values for a 2012 inventory slightly above those reported in 2010. See Table 22 for details.

Types	Working gas capacity (bcf)	Cost per capacity (\$/mcf)	Subtotal (\$B)
Depleted reservoir	3721	10	40.2
Aquifer storage	367	18	7.1
Salt cavern	488	15	7.9
Total \$B			**55.3**

Table 21: Summary of U.S. gas storage capacity and costs, in 2012 dollars. Capacity is taken from the EIA [18] and cost estimates are drawn from industry reports, described in Table 22 and shown in Figure 25.

Year	Salt cavern	Depl. reservoir	Aquifer	Source
		$M/bcf		
1999	10.9	4.3	5.3	[308]
2004	12	5		[309]
2004	27	6		[309]
2009	8.9	7.0	14.4	[156]
2010	11.3	8.9	17.9	[155]
2014	31	18	37	[158]
Assumed	20	10	18	

Table 22: Collected estimates of underground gas storage construction cost, drawn from reports by or prepared for the National Energy Technology Laboratory (NETL) [308], the Federal Energy Regulatory Commission (FERC) [309], and Interstate Natural Gas Association of America (INGAA) [155, 156, 158]. This is the source table for Fig 25. All costs are given as 2012 dollars. In converting nominal to real dollars, we assume that costs in individual reports are stated in current dollars, except for those from the 2009 and 2016 INGAA reports, which are given in 2008 and 2012 dollars, respectively.

F. Coal mining and transport

Coal assets included in our physical inventory consist of only coal mines and the railways used in coal transport. Coal is not significantly processed and is stored simply in piles with minimal capital requirements [68]. We do not book-keep barges or the coal railcars themselves. Coal is used overwhelmingly (93%) in power plants for electric generation, which are covered in Section H. The remaining 7% of coal is used either as a basic energy source for manufacturing in the steel, cement and paper industries, or as a material input to production of steel, chemicals, cement and lime [310].

F.1. Extraction

Coal production in the U.S. has grown slowly but steadily for the past half century, at a bit under 2%/year, so that production has more than doubled since 1950 to about 1 billion tons/year (tpy). Growth is driven by surface mines west of the Mississippi, which now dominate U.S. coal production [311, 312], while production from traditional underground coal mines in Appalachia has been flat since 1950 (Table 23). The shallow coal deposits in Western states can be extracted in large projects with economies of scale and with lower labor requirements than underground mines. In 2012, the 16 surface mines in Wyoming produced about half of all U.S. coal, but employed less than 15% of U.S. coal miners [20, 313].[41] The largest two Wyoming mines alone – the North Antelope Rochelle and Black Thunder, both in the Powder River Basin – produced over 20% of U.S. coal, almost equalling the combined production of West Virginia, Kentucky, and Pennsylvania [20, 313].[42] Western surface mines also have low operating costs because of relatively thick coal deposits under shallow overburden, yielding "stripping ratios" (ratio of total material removed/coal extracted) under 5:1 for Wyoming [313].

Types	# of mines	Product.	Capacity	Cap. /mine
		M tpy		*M tpy*
surface	488	673	855	1.75
underground	719	343	464	0.65
continuous		*157*	*208*	
longwall		*183*	*253*	
other		*3*	*3*	
Total	1207	1016	1284	1064

Table 23: Summary of U.S. coal mine number count, production, and capacity for each mine category. Mines operate at over 70% capacity factor. Mine count and production are taken from the National Mining Association [314], and capacity from production values and capacity utilization rates from the EIA *Annual Coal Report* [19]. Both reports compile data from the U.S. Mine Safety and Health Administration (MHSA) [20] and are consistent to within 5%.

[41] Data compiled by the Mine Safety and Health Administration (MHSA) suggest shares of production and employment of 48% and 14%, respectively [20], while the Wyoming Geological Survey reported 40% and 8% [313]. The MHSA records employment, active status, and production history for individual mines from 2006-2017.

[42] The two largest WY coal mines each produces over 100 million tpy, 100 times the U.S average across all mines [20, 313].

While U.S. coal production rates are well established, coal mine capital costs are not extensively documented. Upfront construction costs are generally low relative to operation costs but quite variable, affected by not only mine size and stripping ratios (for surface mines) but by factors such as the tilt of the coal deposit, the degree of automation, and the means of moving coal from the minehead [21, 315, 316]. The diversity of mine characteristics means that individual projects are minimally useful in establishing aggregate cost metrics for U.S. coal production. Collected upfront cost estimates from globally distributed coal mine projects between 2005–2015 varied by a factor of 30 even for a single mine type (Table 24).

Source	Year	Geographic region	Surface	Underground cont.	Underground longwall	Source
NETL	2011	US		16	64	[317]
ACEA	2005	South Africa	11			[318]
Arctos Anthracite	2012	Canada	263			[319]
Shafiee, Nehring, and Topal	2009	Australia	30-50			[320]
Mohutsiwa	2015	India	10-50	5–107		[321]
Dipu	2011	South Africa/India	32-44	41-59		[322]
Skelly & Loy Engr	2005	Pennsylvania, US		22	19	[323]

Table 24: Collected mine development cost estimates for international surface and underground coal mines, in $ per short ton per year. Canadian and Australian costs are likely comparable to those in the U.S., given similarities in practices and in labor and material costs [315]. The National Energy Technology Laboratory (NETL) report [317] is a modeling study estimating representative national costs; all other values are taken from reports describing individual projects. ACEA [318] is a handbook on surface coal mining released by the South African Colliery Managers Association. In the Mohutsiwa project, surface coal cost range is for only dragline types similar to U.S. mines; truck-and-shovel mines have reported costs up to $170/tpy.

Our cost estimate is informed instead by modeled capital cost estimates from the proprietary *2010 Coal Cost Guide* from InfoMine [21], which models representative U.S. mine projects for different mine characteristics and sizes (Figure 26). Both the InfoMine study and our collected cost estimates suggest that surface mines incur higher capital costs than all underground types, even at the low stripping ratios characteristic of U.S. mines. Cost per capacity (tons/year) declines slightly for larger projects, reflecting economy of scale. In the U.S., where surface mines are considerably larger than underground mines (see Table 23), the two effects nearly cancel, allowing us to assume a uniform construction cost of $50/short ton/year that is appropriate for both the larger surface mines and the smaller underground mines.

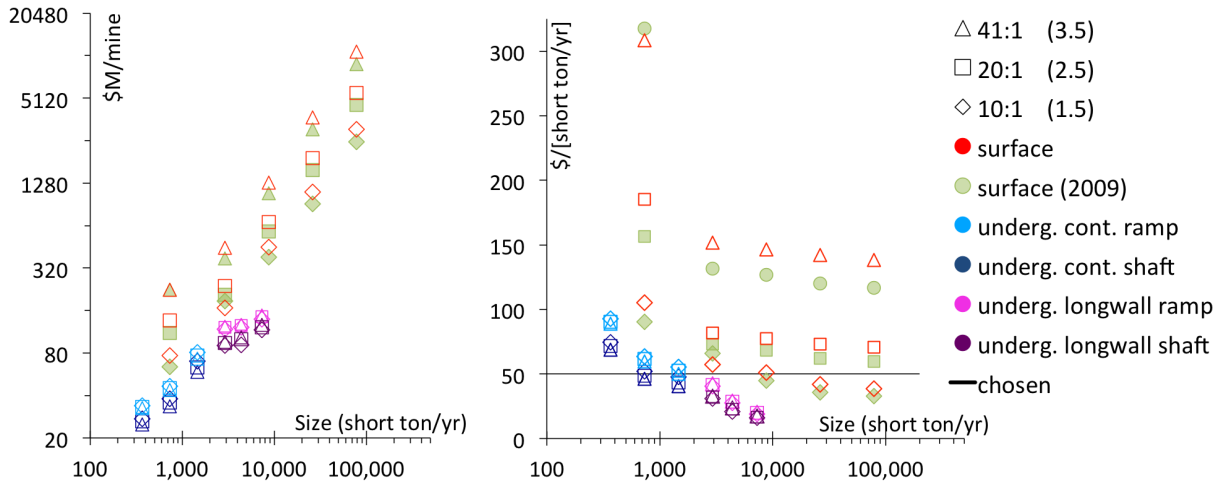

Figure 26: Upfront capital cost estimates for U.S. mines from the *2010 Coal Cost Guide* by InfoMine[21]: **(left)** per mine and **(right)** per capacity. For comparison we also show values from the previous 2009 InfoMine report, reported in [320]. Color differentiates mine types; shape differentiates the stripping ratio for surface mines (41, 20, and 10 to 1) and the formation thickness for underground mines (1.5, 2.5, and 3.5 meter). We assume unit cost of $50/tpy for all mine types (gray line).

We use the 2012 productive capacity reported by the EIA (Table 23) and our \$50/ short ton per year cost estimate to derive a total asset value for U.S. coal mines. We apply an export adjustment because the U.S. is a net coal exporter, with net exports equal to 11% of U.S. production. (See Table 2; destination countries are largely Europe and Asia.) We therefore adjust coal asset value by an export factor of (1-0.11) = 89%. The total asset value of U.S. coal mines in 2012 is then:

$$\text{Cost}_{coal\ mine} \;=\; \$50 \;/\; \text{tpy} \times 1284 \text{ tpy} \times 0.89 \;=\; \$\mathbf{57\ B}.$$

F.2. Transportation

Coal is transported primarily by rail in the U.S., and is the single largest commodity moved by U.S. railroads, making up about 1/3 of all freight ton-miles. (See Figure 27, based on data from the American Association of Railroads (AAR) [324].) We account for rail infrastructure in our physical inventory, as it is expensive and long-lived. For simplicity, we assign a coal rail asset value by applying the coal share to the upfront construction cost of the entire U.S. Class I railroad system. This approach is necessarily crude. While many rail lines do branch to remote locations solely to serve coal mines, most railroad tracks serve a wide variety of freight traffic, and may have been constructed even in the absence of the coal trade.

We omit all other assets associated with coal transport. Barges (12% of coal ton-miles) and trucks (12%) likely have lifespans below than our 20-year cutoff [325].[43] The conveyer and belt loop systems that move coal over short distances near coal mines are not well documented.

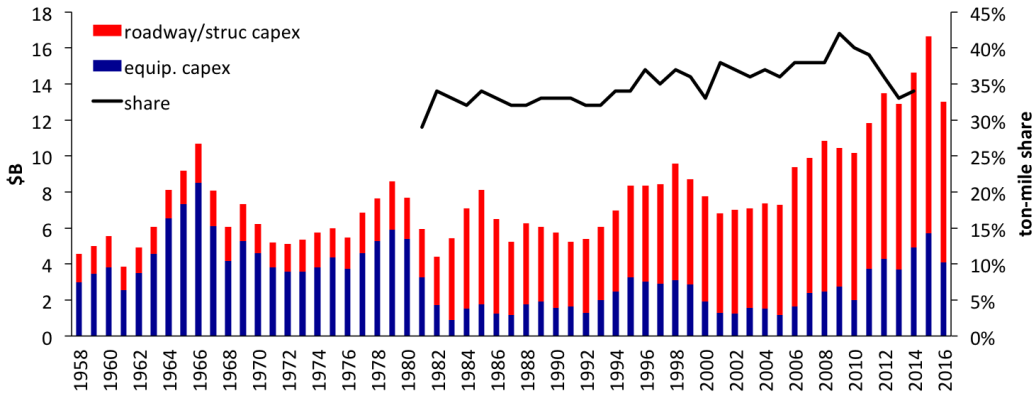

Figure 27: Historical capital and maintenance spending on freight rail infrastructure and equipment, 1958–2016, provided by the American Association of Railroads [326, 327] in separate reports for 1980–2016 [22] and 1953–1984 [23]. Costs are adjusted to 2012 dollars. Total inflation adjusted capital expenditure over the 50-year rail lifetime is \$372 B. Black line shows coal ton-mile share among railroad commodities, from AAR data [324].

We estimate the cost to rebuild the U.S. Class I railroad system as the cumulative capital expenditure over the last 50 years (1962–2012), based on data from the American Association of Railroads [22, 23], which yields \$372 billion (Figure 27). See Appendix M for estimate of 50-year railroad lifespan. As mentioned above, the coal share of rail traffic is around 35% by ton-mile (a measured of combined tonnage and miles of distance traveled) [324]. The coal-related share of asset value in the U.S. freight rail system in 2012 is then:

$$\text{Cost}_{coal\ rail} \;=\; \$372 \text{ B} \times 0.35 \;=\; \$\mathbf{131\ B}.$$

[43] We calculate transport percentages using 2001–2012 average volumes of coal transported by different modes reported by the EIA. We use annual "U.S. Total" volume of coal transported by "Railroad", "Truck", "River", "Great Lakes", and "Ocean Vessel" from EIA annual reports of "Domestic distribution of U.S. coal by origin state, consumer, destination and method of transportation" [325]. We aggregate "River", "Great Lakes", and "Ocean Vessel" together as waterway transportation.

G. Usage (non-electricity)

Usage differs strongly among the three fossil fuels. *Coal* in the U.S. is used almost exclusively for electricity generation, covered in Section H. *Oil* is used predominantly in the transportation sector (70%), almost entirely in the form of gasoline and diesel [328],[44] with the remainder split between industry (25%), where much of its use is as a feedstock for production of plastics and chemicals,[45] residential heating (4%), mainly as propane or distillate fuel oil, and a tiny contribution (1%) to electric power generation [328, Table 3.7a]. *Natural gas* is divided evenly between electricity generation (31%), heating in residential and commercial buildings (27%) and input to industrial processes (28%) [144, 331]. More than half of homes in the U.S. use natural gas for cooking or heating, and natural gas is the most significant fuel used in manufacturing [332], largely as a primary energy source but with some use as a raw material for products such as paints, plastics, explosives, and fertilizer [331]. Fertilizer production alone accounts for ∼1.5% of U.S. natural gas usage [329, 333, 334].

Industrial and residential energy uses are out of scope of this inventory. Residential heating and cooking equipment has a service life too short for inclusion, and industrial process equipment is generally too difficult to evaluate, given the diversity of assets. Many industrial processes also offer possibilities for substituting primary fuel sources, making it difficult to evalute assets in the context of energy transition questions. For example, fertilizer factories, of which U.S.-serving plants have a total value of approximately $15 B,[46] rely almost completely on natural gas (CH_4), which is used to produce first hydrogen (H_2) and then ammonia (NH_3), but a fertilizer factory can be converted to other energy sources by replacing only the initial steam reforming unit used to make H_2 [339–343].

Within transportation, many assets are also shorter-lived than the 20-year cutoff for this inventory. The average lifespan of a motor vehicle, for example, is reported as 13–17 years by IHS Automotive [344]. Aircraft, ships, and barges have longer lifespans, and represent significant asset value: the U.S.-registered commercial and private aviation fleet, for example, consists of over 14,000 aircraft (including ∼7,000 jet airplanes, ∼4,000 twin-engine turboprops and ∼3000 single-engine turboprops [345–347]) with a total replacement cost likely over $500 B. However, much of that value would be retained in a scenario eliminating fossil fuel use, given use of biofuel or at most a substitution of engines.

The only component of energy usage that we represent in the physical inventory is therefore the service stations that sell gasoline and diesel.

Service stations The Census Bureau counts a total of 114,474 service stations selling gasoline and/or diesel in 2012 [348, 349]. The National Petroleum Council (NPC) provides a larger value in a 2012 report [350] of 160,000 service stations and 5,000 truck stops; we conservatively take the smaller number. These stations vary in size and complexity, but multiple sources estimate representative national costs. We take as our primary source a 2013 NREL (National Renewable Energy Laboratory) report on transportation infrastructure [351], which estimates mean capital cost of a new gasoline/diesel station, excluding land costs, as $731,000 in 2005 dollars or $836,103 in 2012 dollars. Two other independent estimates are slightly higher: the NPC report [350] gives $1 million per conventional gasoline station, and Reed Construction Data [352] gives $1.2 million. (Neither source specifies whether land costs are included.) Estimated cost for U.S. service stations is then:

$$\text{Cost}_{serv.\ station} = \$836,103 \times 114,474 = \mathbf{\$96\ B}.$$

[44] The July 2014 Monthly Energy Review gives a total consumption of oil products in 2012 of 18,490 barrels and total consumption within the transportation sector of 13,034 barrels [328, Table 3.5 & 3.7c]. Gasoline and diesel make up 56% and 43% of this consumption, respectively.

[45] The primary industrial feedstock in the U.S. is "oil" as defined here, but the actual raw material used is not crude oil but instead hydrocarbon liquids derived from natural gas processing. By convention these are counted in the oil flow [see methodology in 329]. In this accounting, over 10% of U.S. petroleum ("oil") consumption – the equivalent of 2 M bpd – is used as a feedstock for non-gasoline manufacturing, according to the 2014 Manufacturing Energy Consumption Survey (MECS)[330, Table 2.1, 2.2]

[46] Based on a capital cost of ∼$1100 per ton/yr capacity [333, 335], or ∼30 plants [336] at ∼$500 million each [337, 338].

H. Electricity generation (power plants)

H.1. Summary

About one-third of U.S. fossil fuel usage in 2012 is used to make electricity by driving turbines (or engines) attached to generators [353]. Electricity in the U.S. is used for multiple purposes, including (roughly in order of importance) to drive compressors in air conditioning units and refrigerators; to turn industrial drives and ventilation fans; and to power electronic equipment and appliances such as stoves. Lighting accounts for less than 10% of total U.S. electricity usage. Roughly 2% of U.S. electricity is used in electrochemical industrial processes such as aluminum smelting [353, 354].

We generate our physical inventory of U.S. power generators from a comprehensive survey of operating generators by the Energy Information Agency (EIA), the 2012 EIA 860 survey (henceforth *EIA-860*) [8], and from a variety of sources on generator overnight construction cost, primarily also from the EIA. The *EIA-860* survey collects information annually on all grid-connected generators exceeding 1 MW capacity, and lists them by nameplate capacity, primary energy source (e.g. natural gas, residual fuel oil), and prime mover technology (e.g. combustion turbine, steam turbine), as well as year of first operation. We organize listed power generators into 13 types powered by fossil fuels, and 12 with non-fossil power sources.[47] The resulting count for the year 2012 is 10,161 fossil-fueled generators totaling ∼900 GW (Table 25) and 8,089 non-fossil generators totaling ∼300 GW (Table 26). (Comparing nameplate capacities can be deceptive, since some generator types will operate at far less than nameplate capacity: total U.S. electricity production in 2012 was less than 500 GW [355, Table 1.1].) The generator classification scheme is described in detail in following sections.

We use as our primary cost reference a 2014 EIA report on overnight construction cost for power plants ("Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants 2013" (henceforth *EIA summary* [9]), one of a recurrent series that also includes releases in 2010 and 2016 [356, 357]. For those generator types omitted by this report, we turn to alternative cost sources, in order: 1) the 2013 EIA estimate of the construction cost of new electric generators installed in the last year [10–12], compiled as part of the *EIA-860* survey[48] and 2) the 2014 "Capital Cost Review of Power Generation Technologies" (henceforth *E3* [13]), prepared by the private firm Energy and Environmental Economics, Inc. (E3) for the Western Electric Coordinating Council. We refer to but do not use quantitatively a 2010 review prepared by ICF International for the National Renewable Energy Laboratory (NREL) that collects cost assumptions used in energy models ("Cost and Performance Assumptions for Modeling Electricity Generation Technologies", henceforth *NREL-2010* [358]), because even adjusted for inflation the energy-model cost estimates are typically 25–50% lower than the survey-based values of the *EIA-860* and *E3* reports.

To obtain the total upfront value for each category of generators, we multiply the sum of generator nameplate capacity in each category by its estimated overnight cost. The final aggregated sum is **$2.8 T** for all U.S. power generators operational in 2012, of which those powered by fossil fuels account for the majority of value, at **$1.6 T**. Within the fossil fuel category, the majority of upfront value lies in coal plants at $1.1 T vs. ∼$0.5 T for natural gas plants and <$0.1 T for those powered by petroleum products. The average 2012 cost of U.S. electricity generation facilities per nameplate capacity, across all facilities in the inventory, is 2.4 $\$/\mathrm{W_{cap}}$. Costs broken down by fuel type are 3.2, 1.0, and 1.2 $\$/\mathrm{W_{cap}}$ for coal, oil and gas, respectively, with nuclear at 5.5 and all renewables (dominated by hydropower) at 3.2 $\$/\mathrm{W_{cap}}$. (Note that as mentioned above, these comparisons may be somewhat misleading as capacity factors vary between generator types.) The following sections discuss our methodology for assigning generator categories and costs. Costs in all categories are uncertain to tens of percent, but as is the practice througout this inventory, we retain the significant figures of the original sources. Tables 25 and 26 below summarize the results, and Tables 27 and 28 describe the classification scheme in detail.

[47] We account for 99.8% of capacity in *EIA-860*; <0.2% cannot be sorted into a well-understood type and is omitted.

[48] *EIA-860* construction cost estimates are also available for later years, 2014 and 2015, but we choose the version closest to our benchmark year of 2012.

	Sum of nameplate capacity (MW)	Number of units	Cost per capacity ($/kW)	Total upfront cost ($B)	Cost source
Coal	**336,341**	1,309		**1,092**	
Conventional steam	336,015		3,246	1,091	[9]
IGCC	326		4,400	1.4	[9]
Natural gas (NG)[49]	**488,210**	5,162		**488**	
Natural gas-fired combined cycle	254,281		917	233	[9]
Gas combustion turbine	145,056		973	141	
Conventional steam	85,520		1,272	109	[10–12]
Internal combustion engine	3,211		1,572	5.0	[10–12]
Natural gas with compressed air storage	110		973	0.1	[9]
Fuel cell	32		7,108	0.2	[9]
Oil (petroleum products)	**53,789**	3,690		**64**	
Conventional steam	24,836		1,489	37	[9–12]
Combustion turbine	22,040		973	21	[9]
Internal combustion engine	5,372		765	4.1	[10–12]
Oil- or syngas-fired combined cycle	1,543		917	1.4	[9]
Fossil fuel total	**878,341**	**10,161**		**1,645**	

Table 25: Summary of all U.S. fossil-fueled electrical power generation units in operation in 2012 from the *EIA-860* database [8] along with estimates of upfront cost per capacity for each generator category and resulting aggregate undepreciated values. Right column gives source for each unit cost estimate; see text for details. The *EIA-860* omits non-grid-connected generators serving individual industrial facilities or buildings, which are significant for natural gas. Asset value in these private gas turbogenerators may be ∼$160B; see Section N.3.

	Sum of nameplate capacity (MW)	Number of units	Cost per capacity ($/kW)	Total upfront cost ($B)	Cost source
Nuclear	**107,938**	104	**5,530**	**597**	[9]
Hydroelectric	**99,099**	4,179		**340**	
Hydro conventional	78,241		2,936	230	[9]
Hydro pumped storage	20,858		5,288	110	[9]
Wind onshore	**59,629**	947	2,213	**132**	[9]
Biofuel[50]	**14,047**	2,109		**51**	
Conventional steam (biogas or biofuel)	4,961		1,272	6.3	[9]
Conventional steam (wood or biomass)	4,350		4,114	18	[13]
Conventional steam (municipal solid waste)	2,669		8,312	22	[9]
Biogas combined cycle	199		8,180	1.6	[9]
Internal combustion engine (biogas)	1,438		1,572	2.3	[10–12]
Internal combustion engine (biofuel)	2		765	0.001	[10–12]
Biogas/fuel combustion turbine	414		973	0.4	[9]
Fuel cell	15		7,108	0.1	[9]
Geothermal	**3,724**	197		**22**	
Geothermal binary	3,036		6,243	18.9	[9]
Geothermal dual flush	689		4,362	3	[9]
Solar	**3,215**	553		**14**	
Solar photovoltaic	2,725		4,183	11.4	[9]
Solar thermal	489		5,067	2.5	[9]
Non-fossil total	**287,652**	**8,089**	4,019	**1,156**	
Fossil fuel total	**878,341**	**10,161**	1,873	**1,645**	
Grand total	**1,165,993**	**18,250**	2,413	**2,818**	

Table 26: As in Table 25 but now summarizing all U.S. non-fossil-fueled electrical power generation units. We omit ∼0.17% of listed capacity in *EIA-860* that could not be assigned to an identifiable generator category. Residential solar, which is not included in *EIA-860*, should have asset value less than that of utility-scale solar [359]. The unit count for wind represents wind farms, not individual turbines. Note that wind and solar costs have declined since 2012. Aggregate sum at bottom totals undepreciated asset value for all electrical generation units in the U.S. operating in 2012.

[49] Includes "Other Gas" which EIA listed as a separate fuel category

[50] Includes "Biomass" and "Wood & wood derived fuels" which EIA listed as separate categories

	Energy source code	Description
Coal		
	ANT	Anthracite coal
	BIT	Bituminous coal
	LIG	Lignite
	SGC	Coal-derived synthetic gas
	SUB	Subbituminous coal
	WC	Waste/other coal
	RC	Refined coal
Natural Gas (NG)		
	NG	Natural gas
	BFG	Blast-furnace gas
	OG	Other gas
Petroleum Products		
	DFO	Distillate fuel oil
	JF	Jet fuel
	KER	Kerosene
	PC	Petroleum coke
	PG	Propane
	RFO	Residual fuel oil
	SGP	Synthesis gas
	WO	Oil-other
Nuclear		
	NUC	Uranium, plutonium, thorium
Hydro		
	WAT	Conventional or pumped storage
	WV	Waves
	CUR	Water, current
	TID	Tides
Wind		
	WND	Wind
Solar		
	SUN	Solar
Geothermal		
	GEO	Geothermal
Biofuel		
	WDS	Wood/wood waste solids
	WDL	Woods waste liquids
	BLQ	Black liquor
	MSW	Municipal solid waste
	LFG	Landfill gas
	SLW	Sludge waste
	AB	Agricultural products
	OBS	Other biomass solids
	OBL	Other biomass liquids
	OBG	Other biomass gases

Table 27: Grouping of fuel codes in *E*IA-860 into broad classes of primary energy source. Right column holds the EIA description for each fuel code. Assignment is relatively straightforward. We combine EIA codes for "wood and wood-derived fuels" and "other biomass" to "biofuel". We do not attempt to classify a small (<0.2%) fraction of the database whose fuel codes cannot be readily mapped to a primary group (e.g. "batteries, chemicals"), and exclude these from the inventory.

H.2. Classifying generators in the EIA-860 survey

The *EIA-860* survey provides a limited number of generator attributes: nameplate capacity, energy source, prime mover technology, and date of first operation. It does not contain a more general description of generator technology that would allow immediate assignment of overnight construction reports. We therefore first group generators by fuel code into broad classes by generic "primary fuel source", e.g. coal,

	Prime mover (*Fuel*)	Assigned technology
Coal		
	ST	gas combustion turbine
	CT+CA	integrated gasification combined cycle (IGCC)
Natural gas (NG)		
	GT	gas combustion turbine
	CS or CT+CA	gas fired combined cycle
	ST, OTH	gas conventional steam
	IC	gas internal combustion engine
	CE	gas combustion turbine with compressed air storage
	FC	gas fuel cell
Petroleum products		
	GT	oil combustion turbine
	ST, OTH	oil conventional steam
	CT+CA	oil- or syngas-fired combined cycle
	IC	oil internal combustion engine
Nuclear		
	ST	nuclear
Hydroelectric		
	HY	hydro, conventional
	PS	hydro, pump storage
Wind		
	WT	onshore wind turbine
Biofuel		
	ST (*for WDS,OBS,AB*)	conventional steam (wood or biomass)
	ST (*for BLQ, WDL, OBL*)	conventional steam (biofuel)
	ST (*for OBG, LFG*)	conventional steam (biogas)
	ST (*for MSW*)	conventional steam (municipal solid waste)
	GT	combustion turbine (biogas or biofuel)
	CA+CS	biogas combined cycle
	IC (*for OBG, LFG*)	internal combustion engine (biogas)
	IC (*for OBL*)	internal combustion engine (biofuel)
	FC	fuel cell
Geothermal		
	BT	geothermal binary
	ST	geothermal dual flush
Solar		
	PV+OT	photovoltaic
	ST	solar thermal without energy storage

Table 28: Classification of generators in the *EIA-860* database into technology categories based on primary energy category, prime mover technology, and in some cases fuel code. We omit <0.2% of the database that could not be readily classified.

natural gas, or oil (petroleum products). Table 27 shows the classification scheme used, whose results are consistent with those of the EIA's classification by primary fuel [24, Table 4.3]. We then group generators within these classes into the 27 distinct technology categories of Tables 25 and 26. The final category assignment is primarily by prime mover technology but in some cases also uses information in fuel codes. Table 28 shows details of category assignments.

H.3. Estimating costs

We give details below on cost estimation for selected generator categories. As mentioned above, we draw construction cost estimates primarily from the 2013 *EIA summary* "Capital Cost Estimates For Utility Scale Electricity Generating Plants" [9], and use as backup sources the *EIA-860* survey of the average cost of newly installed generators in 2013 [10–12] and the *E3* capital cost review prepared for Western Electric Coordinating Council [13]. The latter sources are drawn from surveys close to our benchmark 2012 year, but their samples are less generic and may be biased.

H.3.1. Coal

Conventional steam. In the EIA database, 99.9% of the coal generating capacity in the U.S. is described by the prime mover code "ST", for a conventional steam turbine. The remaining 0.1% is labeled as integrated gasification combined cycle (IGCC). No other technologies (such as circulating fluidized bed combustion) are denoted. We assume that U.S. coal plants, whose mean age is very old (capacity-weighted average first operating year is 1975), are overwhelmingly simple pulverized coal units, and use the *EIA summary* estimate for single-unit pulverized coal of \$3,246/kW [9]. Other sources give similar estimates: for example, *E3* [13] gives $\sim$ \$3,600 in 2012 dollars (inflation-adjusted from \$3,700 in 2014 dollars). The EIA-860 surveys for 2013, 2014, and 2015 have no estimates of new-build coal costs for comparison [10–12].

IGCC. The small number of IGCC plants in the U.S. means cost estimates are necessarily uncertain. We use the *EIA summary* [9] estimate of \$4,400/$\mathrm{kW_{cap}}$. *EIA-860* [10–12] does not list IGCC, and the *E3* report [13] lists no estimate for IGCC without carbon sequestration.

H.3.2. Natural gas

Natural gas combustion turbines and combined cycle (NGCC) units. These units make up 80% of natural gas powered generation capacity, and are recent in construction and well-documented in terms of overnight construction capital cost, though cost estimates still differ and costs may vary over time. We use the *EIA summary* values of \$973 and \$917/$\mathrm{kW_{cap}}$ for combustion turbines and NGCC units, respectively [9]. *E3* values are slightly higher: this report further breaks each technology into subtypes and estimates costs of \$825 or \$1200 for combustion turbines and \$1,125 or \$1,200 for NGCC, both per \$/$\mathrm{kW_{cap}}$ [13]. The EIA-860 surveys reported new-build values for combustion turbines and NGCC units of \$726 and \$1,110 in 2013, \$990 and \$1,521 in 2014, but only \$614 and \$779 in 2015 [10–12].

Conventional steam. 17% of natural gas generation capacity in the U.S. in 2012 is gas-fired boilers with steam turbines, a technology choice that would not be built today. These plants are very old, with average first online year of 1965. Essentially all existing plants began construction before the 1978 Powerplant and Industrial Fuel Use Act banned the use of natural gas and oil in electricity generation. Once the Fuel Use Act act was repealed in 1987, the more efficient combined cycle units became the technology of choice for new builds of natural gas power plants using steam turbines. 98% of existing natural gas-steam plants have first online year of 1978 and earlier, and 99% have 1981 or earlier. Because there are no contemporary analogues for cost estimation, we base our assumed cost on that of the steam turbines used in natural gas combined cycle units, listed as \$1,272 / $\mathrm{kW_{cap}}$ for 2013 new builds in the *EIA 860* survey [10–12], but recognize that this is likely an underestimate of the actual replacement cost of existing gas-steam units.

Internal combustion engine. Internal combustion engines represent only 3% of U.S. natural-gas-fired generation capacity. This technology is not assessed in the *EIA summary* [9], but units do appear in EIA-860 annual surveys [10–12]. We use the 2013 *EIA-860* value of \$1,572, but note that costs vary: subsequent surveys in 2014 and 2015 list \$1,332 and \$1,798; *E3* lists \$1,300 in 2014 dollars [13]; a 2014 report from the Northwest Power and Conservation Council Conference gives a mean of \$1,292 in 2012 dollars [360]; and the 2016 updated EIA capital cost summary [357] gives \$1,342 presumably in 2016 dollars, which would be \$1,284 in 2012 dollars.

H.3.3. Oil - petroleum products

This category encompasses a diverse array of petroleum products produced by the oil refining process. Fuels in this category can be gaseous (syngas), liquid (fuel oil), or solid (petcoke). Generator technologies are therefore also diverse. This category has also experienced significant changes in economics over time, largely driven by trends in the oil prices. Capacity in this category is very old, with most dating from before the oil price spike of the late 1970s and the 1978 Powerplant and Industrial Fuel Use Act, which banned the use of natural gas and oil in electricity generation (Figure 28). After the Fuel Use Act act was repealed in 1987, construction of oil-fired power experienced a minor renaissance during a period of low oil prices in the 1990s, but fell again when oil prices rebounded [361]. At present, new builds are largely confined to petcoke plants that burn the residue from processing Canadian tar sands. (Half of all existing petcoke plants were

built in the last decade, as import of heavy Canadian crude ramped up.) Overall, oil and petroleum products play only a minor role in U.S. power generation outside of Hawaii, whose location make transporting coal or natural gas cost-prohibitive, and even in Hawaii oil-fired assets are generally very old. The largest category by capacity of oil-fired generation in Hawaii is conventional steam plants (see below), whose mean year of first operation is 1966.

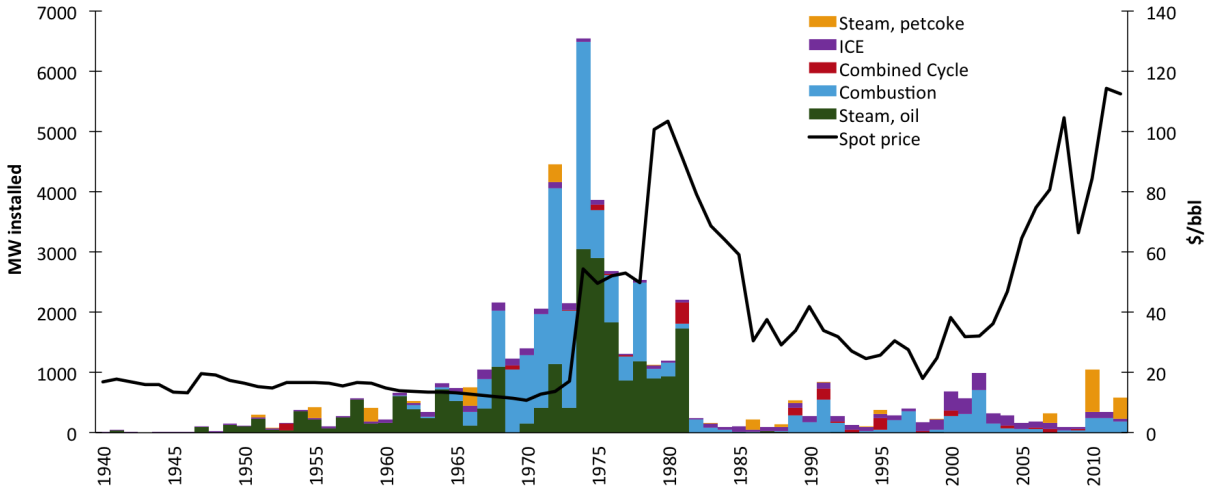

Figure 28: Age structure of generators powered by petroleum products, broken down by prime mover, with historical oil price shown for comparison. Capacity data is from *EIA-860* as described in text; oil price is from BP World Statistical Review [361], where it shows US average for pre 1944, Arabian light (Ras Tanura) from 1945-1983, and Brent crude price from 1984, all adjusted to 2017 by Consumer Price Index, which we readjusted to 2012 dollars. We distinguish between steam turbines running on liquid petroleum products and those running on solid petcoke. Buildup of petroleum-powered generating capacity is strongly influenced by oil prices. Oil-fired capacity builds terminate soon after the passage of the Fuel Use Act of 1978, which banned their use. After repeal of the Fuel Use Act, some construction of oil-fired generation resumes, but largely in the form of combustion turbines and internal combustion engines used as backup or peakers rather than the earlier steam units. Construction of petcoke plants ramps up in the early 2000s with increasing use of Canadian heavy crude.

Conventional steam: Conventional steam plants make up nearly half (46%) of all U.S. generation capacity powered by petroleum products, with most of these (89%, i.e. 41% of all capacity in this category) burning some form of oil. (The remaining 11% are petcoke plants.) Burning fuel oil to drive a conventional steam turbine is an outdated technology that is no longer built. Essentially all such capacity in the U.S. pre-dates the Fuel Use Act of 1978, and the last major project was completed in 1981.

We construct an overall cost estimate for this category by taking a weighted average of assumed costs for oil- and petcoke-driven steam plants, which are quite different. We take the cost of a petcoke-fired generator as that of coal (assumed as \$3,246 / $\mathrm{MW_{cap}}$), though this may be an underestimate. For lack of information on costs of oil-steam plants, we use the same assumption as made for natural gas-steam (\$1,272 /$\mathrm{MW_{cap}}$). The assumption of similarity is supported by the practice of the Natonal Renewable Energy Laboratory in their *NREL-2010* report [358], which groups oil- and gas-fired conventional steam together. The weighted average is then $0.11 \cdot 3246 + \$0.89 \cdot 1272 = \$1{,}489$ / $\mathrm{MW_{cap}}$.

Combustion turbines: Oil- and syngas-fired combustion turbines make up most of the rest of U.S. petroleum-products-powered generation capacity (41%). Though some construction continues even to the present day, these units also tend to be old, with mean year of first operation of 1978. For lack of reliable sources of information, we assign all oil- and syngas-fired combustion turbines the same cost as that for natural gas combustion turbines, using *EIA summary* values [9].

Internal combustion engines: Internal combustion engines make up 10% of U.S. total generation capacity powered by petroleum products. These generators all run on relatively epensive distillate fuel oil (DFO)

and are likely used as backup generators or peakers. Oil-fired internal combustion engines are not listed in the 2013 *EIA summary* [9]. We use the value from the *EIA-860* 2013 new-build survey [10–12], which gives only an aggregate cost for all petroleum liquid generators, but ICEs dominate this value. (ICEs make up 87% of 2013 new liquid-petroleum capacity, vs. 13% for combustion turbines.)

Oil- or syngas-fired combined cycle: Combined-cycle petroleum units in the U.S. are primarily powered by fuel oils, although 20% of capacity uses syngas. These are disproportionately located in Hawaii, where they were built as baseload power. ∼40% of all oil-fired combined cycle capacity is in Hawaii, vs. no more than 5% of any other prime mover type burning petroleum products. Some construction of combined cycle plants continues through the 1990s, givin this category a mean first operating year of 1987. (We defined age as that of the combustion turbine in a combined cycle system; steam turbine ages may differ.) For lack of reliable sources of information, we assign all oil- and syngas-fired combined cycle plants the same cost as that for natural gas combined cycle.

H.3.4. Non-fossil-fuel power generators

Most non-fossil-fuel power generator types are included in the 2013 *EIA summary* [9], our primary reference for capital costs, though not always with the same disaggregation as is provided by the generator count in the EIA-860 survey [8]. The largest categories are relatively straightforward. Nuclear power, the single largest non-fossil generating technology in the U.S. by capacity, is represented by a single estimate of $5,530/kW with no distinction by reactor type. Nuclear power costs are widely acknowledged to be highly uncertain. Conventional hydropower ($2,936/kW), the second largest category, is likewise not distiguished by dam height or other relevant characteristics. Onshore wind, the third most significant non-fossil category in the *EIA summary*, is given a single estimate of $2,213/kW. This value is consistent with data in the U.S. DOE 2014 Wind Technologies Market Report [362], which shows a capacity-weighted mean project cost for new installations in 2012 of ∼$2,000/kW. Note that in 2012, the U.S. had no offshore wind capacity.

Biomass is the most complex category, though it is small in terms of generation capacity, only 5% of all non-fossil generating capacity and 1% of all U.S. capacity. The *EIA summary* contains estimates for three types of biomass-powered generation ("Municipal Solid Waste", "Biomass CC", and "Biomass BFB"), but the EIA-860 allows distinguishing eight distinct types. We identify "Biomass CC" with combined cycle plants powered by biogas (negligible to total U.S. capacity), and "Biomass BFB" (bubbling fluidized bed) with conventional steam plants powered by biomass or wood, which must be higher cost than those burning coal. The *EIA summary* estimate is $4,114/kW; the *E3* report lists a similar $4,300/kW for all generation units termed "Biomass". For the remaining five biomass generator types, all of which involve biogas or liquid biofuel, we use values for equivalent prime movers powered by natural gas or petroleum products.

The EIA-860 report includes only solar projects with capacity > 1 MW, omitting all residential installations and by some estimates more than half of U.S. solar generating capacity [363]. For solar photovoltaic, the EIA-860 identifies only 553 projects in 2012 with a mean capacity of ∼6 MW. To estimate their costs, we use the value for the smallest project class reported in the 2013 *EIA summary*, 20 MW plants with capital costs of $4,183/kW. This value may seem conservative (low) because costs per kW increase for smaller projects, but it is matches the mean for utility-scale projects in 2012 shown in two major reports from Lawrence Berkeley Laboratory (LBL) [359, 364]. Solar thermal plants (also termed "concentrating solar power" or CSP) are far less significant to U.S. electricity, making up less than 20% of utility-scale solar capacity. The U.S. had only 16 CSP projects in 2014, all constructed in the desert Southwest (California, Nevada, and Arizona) [359]. We use the *EIA summary* cost estimate of $5,067/kW [9], which is at the low side of the range of costs collected by LBL [359] for CSP projects built between 2012–2014 (∼$5,000–6,000/kW).

It is important to note that capital costs for both wind and solar PV electricity generation have been declining for many years, and 2012 values are not appropriate for inventories benchmarked to later years. Solar PV costs fell steadily to 2012 due to reductions in module costs; after 2012, they continue to decline due to lowered installation and other non-module costs [364]. By 2016, capital costs for utility-scale solar PV had fallen to about half their 2012 values, and wind costs had fallen by about a third [359, 364]. The levelized cost of generating electricity from wind on good sites is now competitive with fossil generation, even without subsidy [362].

I. Electricity transmission and distribution

The U.S. electrical grid consists of three "interconnections" (Eastern, Western, and Texas), networks of hundreds of thousands of miles of electricity transmission lines and millions of miles of distribution lines that carry electrical power from generators to consumers. Each interconnection carries synchronized alternating current (AC); a handful of direct current "interties" let power flow between them and link them to the national grids of Mexico and Canada. Transmission lines are necessarily operated at a variety of voltages, because long-distance transmission must occur at high voltage to minimize losses while that near residential areas must be lower voltage for safety. The diversity of voltages in the U.S. is especially high, however, because the current system evolved from multiple individual utilities that made differing choices. Each connection between lines of different voltages requires a substation with transformers that alter voltage, from 1-10s of kV at power plants, up to 100s of kV for high-voltage transmission lines, and down to neighborhood distribution at 10s of kV [365]. For residential consumers in the U.S., the final conversation to household 115 or 230 V occurs at pole-mounted transformers that are considered part of the distribution system. Our assessed replacement value for the grid is **$2.20 T**, counting transmission and distribution lines (**$1.81 T**) and substations (**$391 B**). Estimates are summarized in Tables 29 and 32 and described in detail below.

I.1. Transmission and distribution lines

Voltage class, kV	TADS (EIA) 2012	TADS (DOE) 2018	Platts 2015	this work	$M/mile, 2012	$B, subtotal 2012
Distr. - AC <69			**6,375,567**		*0.22*	*1,400*
Trans. - AC single circuit						
69-100	n/a	n/a	**304,194**		0.34	103
100-199	n/a	**211,227**			0.38	80
200-299	**85,417**	86,397			0.93	79
300-399	**56,036**	63,804	n/a		1.30	73
400-599	**26,126**	26,784			1.86	48
600-799	**2,416**	2,391			1.86	4
Trans. - AC multi-circuit						
200-299	**8,092**				0.93	8
300-399	**7,564**				1.30	10
400-599	**947**	**	n/a		1.86	1.8
600-799	0				0	0
mixed	**128**				0.38	0.05
Trans. - HVDC	4,058	3,970		**3,289**	1.50	3.8
Trans. - all	190,784	394,573	697,070			
Trans. - all (adj. to circuit miles)			705,436			410
T&D - TOTAL			**7,081,003**			**1,810**

Table 29: Summary of mileage and cost for U.S. electricity transmission and distribution lines. Mileages used are shown in bold. We use data from three sources: summaries of North American Electric Reliability Corporation's (NERC) Transmission Availability Data System (TADS) database from 2012 [24] and 2018 [25], which provide mileage for medium- and high-voltage transmission lines broken out by voltage class, and the 2015 Platts UDI database [26], which provides total mileage for all U.S. transmission and distribution for 2012-2013. Our primary source is the 2012 TADS-EIA report [24, Table 8.10a], but we take 100-199 kV mileage from the TADS-DOE report and derive 69-100 kV (often termed "subtransmission") by subtracting the combined TADS line mileage from the Platts total. HVDC line mileage is derived by summing individual lines. See text for details. Costs per mile for lines >200 kV are taken from a 2014 report by Black & Veatch on *Capital Costs For Transmission and Substations* [28]; those for lower voltages from the National Council on Electricity Policy's *10-Year Transmission Assessment in 2003* [29], inflation-adjusted and trimmed to 3 significant digits.

Cost.

Transmission. Electricity transmission lines typically consist of bundles of stranded aluminum wire reinforced with steel for strength, hung from poles or towers. Costs rise with the voltage level that lines are operated at, because for safety, a higher-voltage line must have higher towers, larger insulators, and a wider right-of-way [366], and because in practice, higher-voltage transmission lines are designed to carry so much power that they involve higher currents than lower-voltage lines. Since higher currents require thicker conductor bundles, the total cross sections of lines may be over 2000 mm^2 for ultra-high-voltage 700 kV transmission lines but only $\sim$50 mm^2 for 20 kV distribution lines [367]. At very high voltages (>345 kV), lines also become more complex, with conductors divided into multiple bundles per phase, separated by spacers, to reduce the coronal losses that occur in alternating current.

Industry practice is therefore to estimate transmission line costs by voltage class. The units specified are generally $ per "circuit mile", a length measure that assesses "the total length in miles of separate circuits regardless of the number of conductors used per circuit."[368]. An AC circuit consists of three phases carried on separate conductors; a direct current (DC) circuit can be as few as one conductor. Most U.S. transmission lines carry a single circuit, but some carry multiple circuits on the same towers, which reduces costs, so "single-circuit" and "multi-circuit" costs are specified separately.

Our primary source for the transmission line costs of Table 29 is a 2014 report prepared by the engineering firm Black & Veatch (BV) for the Western Electricity Coordinating Council (WECC), titled *Capital Costs For Transmission and Substations* [28]. The BV report provides costs for AC transmission lines from 200–699 kV and for HVDC lines at ±500 kV, which we use for all HVDC. For lower voltage AC lines (<200 kV), we use a 2004 report by the National Council on Electricity Policy (NCEP), their *10-Year Transmission Assessment* [29], that cites cost estimates made by the Wisconsin-based American Transmission Company (ATC). Where the two reports overlap (345 kV single- and double-circuit AC lines), their values agree well (to +5% and −13%, inflation-adjusted). We do not attempt to quantify mileage or costs of underground transmission lines, since in the U.S., virtually all electricity transmission occurs on overhead lines[51].

Distribution. Distribution lines, which carry electricity to individual buildings at relatively low voltages (2 to 69 kV), make up the single largest-value item in the U.S. electrical grid, and uncertainty in their cost dominates uncertainty in total grid valuation. The U.S. distribution system is enormous, complex, and poorly characterized. Ownership is spread among over 3000 individual entities of very different types – investor-owned utilities (IOUs), municipal utilities, and rural cooperatives – and no single agency collects information systematically across all these [369]. The different utility types incur very different costs per line-mile. Rural cooperatives that serve sparsely populated areas and carry small amounts of power over large distances have low per-mile costs; utilities serving dense urban areas can have costs an order of magnitude larger. Factors affecting distribution costs include the voltage, number of phases, and total power carried by a line; the number of lateral lines from each feeder line; whether the line is overhead or underground; and local conditions and land and labor costs.

Information about distribution costs has become more available in the last decade because rising interest in placing distribution lines underground has led to many cost-benefit analyses evaluating options. While underground lines are substantially more expensive than overhead lines (a widely-used estimate is 5-10 times more [372]), in urban areas their higher expense can be outweighed by their improved reliability: underground lines are not affected by winds that take down overhead lines and cause power outages or touch off wildfires. In rural areas, distribution lines are virtually never undergrounded because the distances per customer make the expense too great. The National Rural Electric Cooperative Association estimates that only 18% of their lines are underground [373]; by contrast, in New York City 86% of electric load was distributed underground even before Hurricane Sandy in 2012, and 100% in Manhattan [374].

[51] Capacitive losses in underground lines rise steeply with voltage, making underground transmission costly and introducing significant engineering constraints [369, 370]. Informal estimates suggest that underground lines make up no more than a few percent of U.S. transmisssion, nearly all at the lowest transmission voltages. Reports from individual state Public Service Comissions provide similar values. For example, the Wisconsin PSC estimated that less than 1% of transmission lines in eastern Wisconsin were underground, all at voltages of 138 kV and below [370]. The Florida PSC estimated in 2005 that 1.5% of transmission in Florida was underground, in contrast to about half of distribution [371].

The most widely cited source of distribution cost estimates for is a series of reports ("Out of Sight, Out of Mind") prepared for the Edison Electric Institute (EEI). These reports do not provide national mean costs, but give cost ranges. For overhead lines, the 2012 EEI report [372] gives a range of ∼$110-910 K per circuit-mile for suburban installations, with urban installations 10–15% higher and rural ∼1-20% lower. For underground lines, the suburban range is ∼$530 K - $2.3 M/mile, with urban costs twice as high and rural ones 20–40% lower. The EEI estimates are widely repeated by other studies, e.g. by Lawrence Berkeley National Laboratory [375], by the private company Energetics [376], and by the EIA [377].

Individual utility reports of distribution costs lie within these limits, as expected. As an example of a smaller, less-dense city, the city of Bloomfield, NM estimated their replacement costs in 2012 as $40 K/mile for low-voltage single-phase tie lines, $110 K/mile for 3-phase main lines, and $155 K/mile for replacement of the entire system (which is 17% underground) [378]. California and Florida, on the other hand, which have been actively encouraging undergrounding by implementing cost-recovery mechanisms [379], have higher distribution costs, likely because of denser populations and higher labor costs. Florida Light and Power, one of 5 investor-owned utilities in Florida, estimates costs of $300-400 K/mile for overhead lines and $500 K-$4 M/mile for underground, with 40% of their distribution lines underground in 2017 [380]. In California, the investor-owned Pacific Gas & Electric (PG&E) reports costs of $800 K/mile for overhead lines and $3 M/mile for underground in a 2017 newsletter, with 24% of their lines underground [381].[52] (PG&E's underground fraction appears somewhat low for California: the state Public Utilities Commission estimates that 37% of all CA distribution lines are underground [384].)

To construct average U.S. distribution costs, we use analyses from the National Rural Electric Cooperative Association (NRECA) reported in their "Fact Sheets". These analyses combine information about cooperatives and investor-owned utilities derived from the proprietary ABB Energy Systems database with rougher estimates for municipal utilities. NRECA values are cited in the 2016 "Electricity Distribution Baseline Report" prepared by the Pacific Northwest National Laboratory for the Department of Energy [369]. We estimate costs per distribution line-mile using two versions of the NRECA analysis, one based on data from 2009–2010 [30] and another on 2014-2015 data [31], and distribution line-miles taken from the 2015 release of the Platts UDI database, a directory of electric power producers and distributors compiled by the consulting firm Platts [26]. (The Platts UDI database is described in detail in the following section). Resulting 2012 costs range from <$60 K/mile for rural co-operatives to ∼$300 K/mile for IOUs to ∼$600 K/mile for municipal utilities, and yield a national mileage-weighted average of **$220 K/mile** (Table 30).

Utility type		Miles (%)	Energy sales (%)	Assets ($B)	Cost ($K/mile)
IOU	*2010*	50	73	904	273
	2014	50	73	995	322
Co-op		42	11	145	52
		43	12	164	62
Muni		7	16	270	583
		7	15	272	627
U.S. mean					**220**

Table 30: Values from NRECA analyses based on 2009-2010 and 2014-2015 data [30, 31]; original values are given in historical dollars but here are inflation-adjusted to 2012. Co-op financial data is based in part on RUS Form 7 (annual surveys by the Rural Utility Service (RUS), a part of the U.S. Dept. of Agriculture) and, if available, on CFC Form 7 (surveys by the National Rural Utilities Cooperative Finance Corporation). Data for IOUs is taken from EIA form 861. We derive cost per mile by combining NRECA values for total asset value (undepreciated replacement cost) and fraction of line-miles for each utility type with total distribution line-miles from the 2015 Platts UDI [26]. The Platts 2015 value (6.38 M miles) is 3% higher than the value implied by NRECA text (6.2 M total miles), but the total asset value derived from multiplying $220 K/mile by the Platts 2015 mileage differs by <0.5% from the sum of asset values here.

[52] PG&E filed for bankruptcy in 2019 after one of their transmission lines set off the 2018 Camp wildfire, which killed 86 people [382, 383].

Note that any estimate of the replacement value of the U.S. distribution system will be a moving target because of increasing costs. The EIA estimates that the cost of delivering electricity increased by nearly 50% between 2006 and 2016 (from 2.2 to 3.2 cents/kWh) [385]. Much of that rise is due to changes in the distribution system (though a report by the Energy Institute at the University of Texas, Austin finds that transmission costs have risen more steeply [386]) [53]. The 2012 EEI "Out of Sight, Out of Mind" report on transmission and distribution states that "the cost of building electrical facilities has increased in all locations and construction categories" since their 2009 report [372]. Distribution costs are rising not only because of undergrounding but because of increased use of smart metering and other technologies that allow time-variable pricing or demand-side management [369]. Positive cost trends may mean that NRECA underestimates the replacement cost of the U.S. distribution system using current technologies, since their estimates are constructed without historical price adjustments. It is worth noting that NRECA values appear lower than those from the EEI, though the two sources are not strictly comparable. NRECA values imply a mean distribution cost of ∼$57 K/line-mile for rural co-ops, derived from co-op survey responses. The EEI estimates a *minimum* cost for rural distribution of $87 K/line-mile, but this value is based on surveys not of co-ops but of investor-owned utilities in rural areas (defined as 50 or fewer customers per square mile).

Mileage.

Data on transmission and distribution line mileage is derived from three primary sources, described in detail below: two summaries of the North American Electric Reliability Corporation's (NERC) Transmission Availability Data System (TADS), and the 2015 Platts UDI database, a directory of electric power producers and distributors compiled by the consulting firm Platts [26]. The TADS database provides mileage for all medium- and high-voltage transmission lines broken out by voltage class, but it is not publicly available, so we rely on partial summaries in secondary reports by the EIA [24] and DOE [25]. The EIA summary omits all lines under 200 kV, and the DOE summary omits lines under 100 kV and all multi-circuit lines. The Platts UDI database provides total mileage for all U.S. transmission and distribution, but without voltage information. We therefore combine all three sources for a full inventory. We take as our primary source the 2012 TADS-EIA report [24, Table 8.10a], but we take 100-199 kV mileage from DOE TADS and we derive 69-100 kV mileage by subtracting the combined TADS mileage from the Platts total. These two lowest voltage classes cannot be neglected as they dominate the U.S. transmission system by mileage and account for nearly half of its asset value. Finally, the handful of high-voltage direct current (HVDC) lines in the U.S. are reported so inconsistently that we forego all databases and simply count them individually. Sources are described in detail below.

- **Platts UDI – transmission & distribution**. The Platts UDI Directory of Electric Power Producers and Distributors [26] is a well-known proprietary directory of North American transmission and distribution networks, covering all regulated utilities as well as major non-utility generating companies and service providers. The database provides summaries of transmission and distribution mileage broken down by country (U.S., Canada, Mexico) and sector (e.g., Investor-Owned, Municipal & Local Government, Rural Electric Cooperative, and Federal, State & District Government), but not by voltage or other technical classes. We use the 2015 UDI report, which covers operations in FY 2012 and 2013, and reports a total 697,070 transmission miles for the U.S. and 6,375,567 distribution miles. (Note that the Platts UDI reports have since been discontinued, after the merger of Platts with the SDG Global Consulting Group to form S&P Global Platts.) Platts UDI deviates from industry standards in reporting "line mileage" rather than circuit mileage. For overhead lines, "line mileage" is equivalent to "pole mileage", which disregards how many circuits or conductors are supported the structure:[54] one

[53] The U.T. Austin report finds a mean cost of delivering electricity of 2.9 cents/kWh (in 2015$) based on data from 1994–2014, generally consistent with the EIA's estimates of 2.2–3.2 cents/kWh in 2006 and 2016 (in 2016$) [385, 386].

[54] "Line mileage" convention differs for overhead and underground lines, with overhead miles assessed as pole miles but underground lines by circuit miles. The distinction is not important here because multi-circuit underground transmission lines are negligible in the U.S. grid.

mile of poles carrying two 3-phase circuits is one pole mile but two circuit miles. We roughly adjust for this reporting difference by assuming that all multi-circuit lines itemized by TADS carry two circuits, which adds 8,365 miles (+1%) to the Platts transmission total, bringing it to 705,436 circuit miles.

- **TADS – transmission only**. The North American Electric Reliability Corporation's (NERC) Transmission Availability Data System (TADS) is a data-gathering effort launched in 2007 that collects mandatory reports from all transmission owners in the 48 contiguous U.S. states. Transmission operators provide detailed annual summaries on their system characteristics, including AC line mileage broken down by six voltage classes and DC by seven classes [387].

  The TADS database is not publicly available, but several federal agencies provide detailed partial summaries of it. We use as our primary source the EIA's 2012 *Electric Power Annual* report [24, Table 8.10a], which covers transmission lines over 200 kV. For lines between 100-199 kV, we use the reported value from the Department of Energy's 2018 *Annual U.S. Transmission Data Review* [25], which summarizes TADS data as of 2017. The DOE review does not distinguish between single-circuit and multi-circuit lines, but its values agree closely with the EIA AC single circuit mileage (Table 29), suggesting that they report only single-circuit. (Differences are <5% for all voltage classes other than 300-399 kV, where it is 15%.) The DOE value may therefore slightly underestimate 100-199 kV transmission, but the number of multi-circuit lines in this class is likely small. Neither the EIA nor DOE report lists the extremely low-voltage (<99 kV) lines that are often termed "subtransmission", although these lines are included in the TADS surveys. We assume that this voltage class accounts for the difference between the adjusted Platts mileage and the aggregate TADS value: 705,436 - 401,241 = 304,195 miles. The resulting mileage estimates decline monotonically with increasing voltage, which is broadly reasonable.

- **HVDC transmission**. In 2012, the U.S. had only eight HVDC lines. These are often reported inconsistently, in part because no set convention exists for the describing bipolar DC lines: a system of two conductors carrying ±500 kV for 1000 miles may be reported as 500 or 1000 kV in voltage and as 1000 or 2000 miles in length. Although the EIA and DOE reports both summarize HVDC lines in the TADS database, their values are inconsistent both in voltage classification and in total mileage. Rather than try to reconcile the discrepancies, we simply count mileage for individual lines (Table 31).

HVDC line name	Year	kV	Power (MW)	Length (miles)
Pacific DC intertie	1970	1000	3100	846
Path 27 (Intermountain)	1986	1000	1920	488
Quebec / New England	1991	900	2250	920
CU	1979	800	1000	427
Square Butte	1977	500	500	465
Neptune	2007	500	660	65
Trans Bay	2010	400	400	53
Cross Sound	2002	300	300	25
Total mileage				3,289

Table 31: High Voltage Direct Current (HVDC) electric power transmission lines in the U.S. in 2012. Note that as of 2012, no major line had been constructed in the previous 20 years. Most data are taken from summaries by the ABB group, which provides engineering services for many U.S. HVDC lines [388–392]. Information on the Neptune and Trans Bay lines are taken from project webpages [393, 394]. All but the Neptune line are bipolar; for bipolar lines we state the full span as the voltage (e.g. ± 500 kV is 1000 kV here). We count the entire length of the Quebec/New England HVDC line that carries hydropower to the Boston area, even though this line now also serves Montreal, since its original rationale was to link the asynchronous U.S. and Canadian grids. We do not include the short DC interties used to connect the Eastern, Western, and Texas grids.

I.2. Substations

Substations in the U.S. vary by orders of magnitude in size, power, and cost. The largest, serving high-voltage long-distance transmission lines (> 500 kV), can handle over a GW of power (thousands of MVA) and thousands of Amps of current. By contrast, the distribution substations that serve individual neighborhoods, stepping voltages down to ∼10 kV for local distribution, may handle less than 5 MW (5 MVA). The typical U.S. substation has 1–3 transformers [28, 395], but large facilities may have as many as 20 [396, 397]. While substation cost is correlated with the power that a substation carries, power ratings are not regularly recorded, so substation costs are typically book-kept in voltage categories instead. We use separate sources for high-voltage transmission substations (230 kV and up), for lower-voltage transmission substations (100-230 kV) and for the distribution substations that lower voltages to the 10's of kV used in distribution lines. By convention, substations are denoted by the highest voltage they handle. Substation number counts are not well recorded in literature, and published estimates tend to focus only on the small number of ultra-high-voltage substations (e.g. [398]). We take substation information from two versions of the "Homeland Infrastructure Foundation Level Data" (HIFLD) Electric Power Transmission Lines database, described in detail below. Resulting asset values are given in Table 32.

Substation kV	HIFLD	arcGIS (ORNL)	$M/station 2012	$B, subtotal 2,012
<100	**7,196**	4,119	2.5	18
NA	**15,583**	32,836	2.5	39
100-161	**21,813**	14,510	5	109
200-287	**3,872**	3,563	37	143
345	**1,336**	1,384	42	56
500	**459**	453	53	24
735+	**36**	34	66	2
Total	**50,295**	56,907		**391**

Table 32: Summary of numbers and replacement cost of U.S. electrical substations. For substation counts, we use the Department of Homeland Security Homeland Infrastructure Foundation Level Data transmission line database ("HIFLD"), provided by Oak Ridge National Laboratory (ORNL) [27]; we derive substations by finding the intersection of transmission lines of differing voltage, or terminations of transmission lines. These values are shown in bold; for comparison, we show counts derived from a second database ("ORNL") that is likely a prior version of HIFLD. Costs for high-voltage transmission substations are taken from a modeling study by Black & Veatch [32], and those for low-voltage transmission and distribution substations from collected project costs and other literature sources. We assume that substations of unknown voltage are distribution and assign them to the lowest cost class.

Cost.

For **high-voltage transmission substations**, our primary source for the cost values in Table 32 is the 2009 Black & Veatch (BV) report *Generation & Transmission Model Methodology & Assumptions* [32], which provides cost estimates by voltage class. For U.S. transmission substations at 230, 345, 500, and 765 kV, BV reports costs of $35, 40, 50 and 62.5 M in 2009 dollars, or $37, 42, 53, and 66 M in 2012 dollars.

Costs of tens of millions of dollars for high-voltage substations are supported both by collected project costs and by other literature sources. Figure 29 shows costs from individual substation projects described in company publications, news articles, or press releases, including 7 values for substations at 230 kV and 1 at 345 kV [399–407]. These average to $33 and $46 M, consistent with our values of $37 and $42 M.

The 2014 BV report *Capital Costs For Transmission and Substations* that serves as our primary source for transmission line costs also provides a cost parametrization for substations based on their detailed characteristics, such as the power rating and number of transformers, shunt reactors, and capacitors. The study describes a sample 500kV substation with a cost of $83 billion, higher than our $53 M value. We also use the BV cost model to simulate alternative configurations for 230 and 500 kV substations, obtaining values of $11 and $18 M using characteristics from a modeling study by authored by Energy + Environmental

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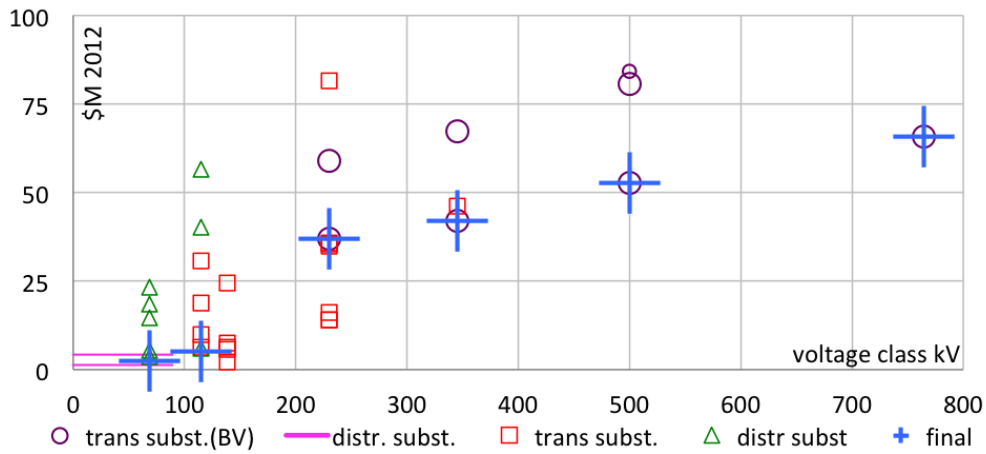

Figure 29: Literature and collected project costs of substations, and chosen values used here (blue crosses). Purple circles show national estimates for substations 230kV or higher from Black & Veatch, most from our primary cost source, a 2009 electricity modeling study [32] and one estimate (500 kV, $80 M) from a 2014 study [28]. Red squares show collected project costs for ∼138 and 230 kV transmission substations [399–407, 410, 411, 414, 415]. Green triangles show collected costs for regional 69 kV substation projects [414–418]. Pink lines are taken from academic journal articles [419, 420]. We exclude values from substations that have significant underground components, which drive up costs and are not representative for the U.S.

Economics (EEE) for the Western Electricity Coordinating Council (WECC) [408], and $21 and $60 M when we add in reactive components.

Lower-voltage transmission substations (100–200 kV) are far more numerous than high-voltage substations but are not described in the 2009 BV report [32]. Note that the voltage classes do not cleanly separate substations into transmission and distribution categories, and this particular class likely contains a mixture of both. (There are some examples even of distribution substations that step down from 230 kV to 20 kV.) The *Power Distribution Planning Reference Book* (by H. Lee Willis, written in 1997 and revised in 2004 [409]) gives a typical value for a 138 to 12.47 kV urban or suburban distribution substation at $1.5 to $6 M in 2004 dollars, i.e. $1.8 to $7 M in 2012 dollars. Our collected cost estimates yield higher values: 12 individual distribution and transmission substation projects in the 100–200 kV range (Figure 29, red squares and green triangles) average to $18 M, though most are under $10 M [399–404, 410–415]. We assume that collected costs may be biased somewhat high since the larger and more expensive projects receive greater publicity, and choose $5 M as a reasonably conservative value.

For **distribution substations, < 100 kV**, reliable cost estimates are more difficult to obtain. The <100 kV voltage category should be entirely distribution stations, which are poorly documented. We again compare several literature sources and collected project costs. Willis [409] does not provide general costs for 69 kV substations. A paper from several decades ago (Manikin, 1990 [420]) reports a cost of only $0.83 M per distribution substation in 1990 dollars, or $1.3 million in 2012 dollars, but substation costs have been increasing over time because of new technologies [416] and trends toward higher power ratings [417]. A 2004 journal article (Balducci et al. [419]) reports 11 new distribution substations projects totaling $39 million, i.e. $3.5 M per substation in 2004 dollars or $4.3 M in 2012 dollars. These values are shown as pink lines in Figure 29. We have also identified 7 reports of project costs in this voltage class, ranging from under $2 M to over $20 M, with median $5.4 and mean $10.1 M, but we expect again that collected cost reports would be biased higher than national-mean values, since industry or media reports would focus on larger projects. We choose a conservative $2.5 M per 69 kV substation, appropriately lower than our estimate of $5 M per 138 kV substation, since these should generally have lower power ratings and lower costs.

Counts.

Some substation information has in the past been included in the Department of Homeland Security's "Homeland Infrastructure Foundation Level Data" (HIFLD) Electric Power Transmission Lines database, provided by the Oak Ridge National Laboratory (ORNL). However, in 2018, all HIFLD geospatial data on substations were moved from open to "secure" status and are no longer publicly available. To assess substation counts, we use one unofficial versions of this geospatial database and one official version of transmisson line database from the same source (ORNL) , described below. Information from both is shown in Table 29. Note that the HIFLD database includes much incomplete reporting, with many transmission lines and ∼30% of substations listed with unknown voltage. We conservatively assume that all substations whose voltage class cannot be determined are distribution and assign them to the lowest cost category.

- **HIFLD**. We derive substation counts from the 2018 release of the HIFLD transmission line database [27] by assuming that each line segment must end with a substation. The database is organized based on individual transmission lines with VOLTCLASS and SUB1 and SUB2 (substations 1 and 2) labels. We identify 50,295 unique substations by name (all unique names under SUB1 and SUB2), determine voltage ratings for all transmission lines connected to individual unique substations, and deduce the voltage range for each substations (e.g., a 115 kV to 69 kV conversion). Although no distribution lines are shown, we assume that end points of lower-voltage transmission lines are distribution substations.

- **arcGIS online (ORNL)**. A 2016 transmission line database was uploaded to the open-source platform ArcGIS, credited to ORNL [421] and almost certainly a prior version of HIFLD. The attribute table lists a total of 56,909 substations, with each entry associated with a maximum and minimum voltage, city, state, number of lines, and data source (imagery, state energy commission, company shape, open street map).

The two databases are reasonably consistent in terms of numbers, though not identical, and both are in general agreement with other sources. For example, a 2014 Congressional report [398] gives 2,100 substations at 345 kV and above and Platts [422] gives 4,600 substations at 230 kV and above; Table 29 sums are 1,831 and 5,703, respectively. Those sources that disagree appear less careful. A 2018 National Resource Council report [423] quotes 15,000 high-voltage transmission substations and 60,000 distribution substations, but provides no sources. A 2017 DOE report [424] quotes 55,000 transmission substations, apparently conflating transmission and distribution.

J. Depreciated energy infrastructure value in the BEA FAA

The most comprehensive assessment of infrastructure value in the U.S. is made by the Bureau of Economic Analysis (BEA) in their Fixed Asset Accounts (FAA), which estimate net capital stocks for all sectors in the U.S. This section describes the first step in validating our inventory against BEA values: we use the BEA FAA to estimate the depreciated value of all energy-related assets in the U.S. and then disaggregate those associated with fossil fuels. In Appendix K, we then develop analogous values from our physical inventory by constructing age structures for selected asset categories and depreciating according to BEA procedure.

The BEA FAA estimates asset values based on not a physical inventory, as in this work, but on past investment flows via the "perpetual inventory method". The BEA compiles annual industry capital expenditures from a wide range of industrial and governmental surveys, and computes depreciated capital stocks as the accumulated past gross investment reduced by asset-specific cumulative depreciation. Data sources include the Census Bureau's Annual Survey of Manufacturers (ASM) and Annual Capital Expenditures Survey (ACES); for details see [425, 426]. We use both the "Standard Fixed Assets Tables" [427, 428], which present aggregate net capital stock values broken down by sector (residential, nonresidential, government), and the more granular "Detailed Fixed Assets Tables" [429] which take the nonresidential asset groups and break them down by multiple categories.

In this section, we use the BEA in three ways to derive asset values for the entire energy sector and for that part related to fossil fuels. K.1) We first replicate the approach of a 2009 paper [430] that used the "Standard Fixed Asset Tables" to roughly asses infrastructure and durable goods for the U.S. energy sector, and derive a value of **$4.0T** (in 2012 dollars) for 2012 assets (Table 33). K.2) We then show that the more detailed "Detailed Fixed Assets Tables" produce a similar estimate with broad industry and asset categories sum, yielding a value of **$4.4T** (Table 34). K.3) Finally, we develop an improved methodology based on detailed matching of items in the Detailed Fixed Asset Tables using industry- and asset- specific code labels, and derive a value of **$4.5T** (Table 35). The detailed matching allows disaggregating the part of the energy sector used exclusively with fossil fuels, which totals **$3.2T**. In K.4), we give details of the methodology and the matching to categories in our physical inventory.

The BEA-derived estimate of energy-related asset value is likely an underestimate, since it omits all assets associated with foreign oil and gas extraction, and some domestic energy-related domestic assets cannot be cleanly separated from the total. The accounting should however be relatively complete for three major categories – pipelines, power plants, and domestic oil and gas wells – providing a means of comparing with our physical inventory.

J.1. Methodology in 2009 NBER working paper by Metcalf [430]

A prior BEA-based estimate of total capital stock in the energy sector appears in a 2009 National Bureau of Economic Research paper on tax policy and energy investment by Metcalf [430]. The methodology involves simply summing seven categories in the BEA Standard Fixed Asset Tables, five from "Section 2, Private Fixed Assets by Type" and one from "Section 7 Government Fixed Assets", This approach does not yield an accurate inventory of energy infrastructure, and represents neither an upper nor a lower bound on that value, since it includes non-energy assets in many categories but also leaves out important asset items such as pipelines. We replicate it here to allow comparison of our method to prior approaches in the literature.

Metcalf used a 2007 version of the FAA [427] (v2007) and obtained an estimate for all energy-related assets in 2007 of $2.9 trillion in 2007 dollars, equivalent to $3.2T in 2012 dollars. We apply this methodology to the more recent v2013 release [428] and tally assets for 2012 to produce an estimate of $4.0T in 2012 dollars (Table 33). The apparent large (nearly 50%) 2007–2012 increase in U.S. energy-related assets, during a period when U.S. energy use actually declined [431, Table 1.3], is an artifact of the BEA's price adjustments: BEA asset tables generally involve different price adjustments for each year. Using a BEA dataset with consistent adjustments yields a 2007 value only 8% below that in 2012 (Figure 46).

BEA Asset Type	2007	2012
Private fixed assets ($M)		
Equipment and software	$ 524	$692
Engines and turbines	84	109
Electrical transmission, distribution, and industrial apparatus	358	459
Mining and oilfield machinery	50	97
Electrical equipment, not elsewhere classified	33	26
Structures	$2,120	$2,994
Power	1,231	1,672
Mining exploration, shafts, and wells	890	1,323
Government fixed assets ($M)		
Power	$242	$317
Total	**$2,886**	**$4,003**

Table 33: Depreciated value for the U.S. energy sector, based on BEA FAA Standard Fixed Asset Tables and the category selection of Metcalf (2009) [430]. 2007 values are from Metcalf (2009), and 2012 values are calculated from the v2013 FAA [428]. Values are not strictly comparable, since the BEA asset tables provide values in what the BEA terms "current costs", i.e. with different inflation and price adjustments for each year.

Private assets, selected based on NAICS Industry Code			$M, 2012
2110	Oil & Gas Extraction		1,434
2120	Mining, Except Oil & Gas *(assume 40% coal share)*		62
4860	Pipeline Transportation		181
2200	Utilities		1,970
3240	Petroleum and Coal Products		169
Subtotal			$3,816
Private assets, selected based on BEA Asset Type Code		*total*	
EI21	Steam engines	*95*	19
EI60	Electric transmission and distribution	*459*	121
EO50	Mining and oilfield machinery	*91*	23
SM01	Petroleum and natural gas	*1238*	34
SU30	Electric	*1086*	15
SU40	Gas	*361*	3
SU50	Petroleum pipelines	*112*	2
SU60	Wind and solar	*111*	59
Subtotal (non-overlapping)			$276
Government assets – Power			$317
Total (non-overlapping), 2012			**$4,409**

Table 34: Depreciated value for the U.S. energy sector, based on the v2013 BEA Detailed Fixed Asset Tables [428] (plus government power assets from the Standard Fixed Asset Tables). The first group are relevant industries (based on NAICS industry code) summed in total (although we take only 40% of [2120 Mining, Except Oil and Gas], based on coal share of U.S. mining revenue). The second group are energy-related assets (distinguished by BEA asset type code) summed over those industries not previously counted (plain text). For comparison we also show (italics) the total sum over summed over all industries. Final total includes only non-overlapping assets.

J.2. Methodology using BEA Detailed Asset Tables, broad categories

The more granular "Detailed Fixed Assets Tables" [429] for private non-residential assets allows constructing a more comprehensive estimate for energy sector, because they categorize capital stock in two dimensions by both industry classification and asset type. In this rough, estimate, we tally clearly energy-related industries and asset types. We first identify and sum four industry categories that lie entirely within the energy sector (e.g. [2110 Oil and Gas Extraction]), and a fifth ([2120 Mining, Except Oil and Gas]) that includes substantial energy-related activities. (Because coal contributes ∼40% of the revenue of mining activities in the U.S. (excluding oil and gas) [432], we assume that 40% of asset value in [2120] relates to coal). We then attempt to identify energy-related assets within other industries. While BEA FAA industry classification is based on North America Industry Code Standards (NAICS) [433], it is not as fine-grained as the NAICS allows, and many sectors are assigned generic versions of codes that encompass both energy and non-energy assets. For example, BEA tables include the broad industry category [2300 Construction] but not the detailed sub-categories that would allow differentiating [237120 Pipeline and Related Structures Construction]. We therefore turn to the BEA asset type codes and identify ten energy-relevant codes (e.g., "SU50 Petroleum pipelines"), and tally these across all industries not already included in the assessment. For example, 48% of industry category [2130: Support Activities for Mining] involves the ten energy-related asset codes and therefore contributes to the final sum. The total of $4.4T exceeds the prior estimate of $4.0T based only on standard asset classes (Table 34).

J.3. Methodology for this work

Determining a more accurate asset value for the U.S. energy sector, and separating out that part relating to fossil fuels, requires a more complicated methodology. We therefore extend the accounting of energy-related assets based on the Detailed Fixed Assets Table by sorting assets into combinations of industry code and asset type. This more detailed procedure allows matching distinct groups with the physical assets of our inventory. Some categories cannot be fully disaggregated and must be omitted even though they contains some energy-related assets. For example, while gasoline stations can have an NAICS code ("4470 Gasoline Stations"), the BEA tables reports only the aggregate value of the generic category "4400 Retail Trade", of which gasoline stations make up a tiny fraction. The analysis is summarized in Table 35, which shows each energy inventory asset category, the BEA FAA categories that we have assigned to it, and the resulting depreciated asset valuation. Total value for the entire energy sector is $4.5T.

The detailed category matching in Table 35 allows identifying and segregating those assets related to fossil fuel use. In most cases this segregation can be done cleanly. For example, we include in the fossil category all of industry code [3240 Petroleum and Coal Products], which encompasses oil refineries, and eliminate nearly all of asset code "E160 electricity transmission and distribution" to exclude the electrical grid. However, in the case of the power plants that generate electricity, which are largely in asset code "SU30 Electric", the BEA offers no means of distinguishing between fossil and non-fossil facilities. We therefore use our own inventory to determine a breakdown and apply that factor to the estimated cost. (See Section K for derivation.) Following the BEA practice of book-keeping wind and solar plants separately, we determine that 64.3% of depreciated capital stock in power plants other than wind and solar involves facilities that burn fossil fuels (oil, gas and coal). The remaining 35.7% are nearly all nuclear and hydropower.

The $4.5T value of Table 35 likely an underestimate of the true depreciated asset value of infrastructure serving U.S. energy use, though it is not a formal lower bound. As mentioned previously, several asset items in our inventory have no analogue in the BEA tables. Foreign oil and gas extraction makes up nearly $1 T of our inventory value, but the BEA tables include only assets located in the U.S. However, we also suspect that domestic oil and gas extraction is substantially over-valued in BEA asset tables, not only because the BEA includes additional expenditures excluded in our physical inventory (exploration and drilling of dry holes), but because the BEA's price adjustments for oil and gas appear excessive. This issue is discussed at length in Section L, in which we recompute the 2012 asset value for domestic oil and gas extraction using BEA historical investment data with no price adjustments. The resulting total of $1.1 T is 33% lower than than the $1.47 T value in Table 35. Because the BEA's price assumptions play such a strong role in their oil and gas asset valuation, we show both price-adjusted and non-adjusted versions in Section K, where we compare BEA-derived asset values with depreciated and undepreciated values in our physical inventory.

	Energy Inventory Category	Industry	Asset Item	US $M, 2012
Fossil Fuel	Oil and Gas Extraction	2110 Oil & Gas Extraction	All, excl. ET40	1,470
		2130 Support Activities for Mining	SU40 Gas, SM01 Petroleum & natural gas	
		All industry, excl. 2110, 2120, 2200, 4860, 3240	EO50 Mining and oilfield machinery	
	Foreign Oil & Gas Extraction Import Transportation	2110 Oil & Gas Extraction	ET40 Ships and boats	17.4
	Coal Mines (40%)	2120 Mining, Except Oil & Gas	All, excl. ET50	60.8
	Refinery & Processing Plants; Oil and Gas Storage	2300 Construction	SU40 Gas SM01 Petroleum & natural gas	158
		3240 Petroleum and Coal Products	All, excl. EO50, SU30, SU40	
	Oil and Gas Pipelines	All Industry	SU50 Petroleum pipelines	485
		4860 Pipeline Transportation	All	
		2200 Utilities	SU40 Gas	
	Coal Railroads (35%, 40%)	All industry 2120 Mining, Except Oil & Gas	SU12 Track Replacement (35%) ET50 Railroad equipment (40%)	69
	FF Power Plants (64.3%)	2200 Utilities	SU30 Electric	960
		2200 Utilities	EI22 Internal combustion engines	
		All industry excl. 2110, 2120, 4860, 3240	EI21 Steam engines	
		Federal NonDefense	Power	
		State and Local	Power	
	Other Oil and Gas	All industry, excl. 2110, 2120, 2130, 2200, 2300, 3240, 4860	SU40 Gas	1.6
		All industry, excl. 2110 2120, 2130, 2300, 3240, 4860	SM01 Petroleum & natural gas	
	Total Fossil Fuel, 2012			3,222
Non-Fossil Fuel & Other	Electric Transmission & Distribution	All Industry	EI60 Electric transmission & distribution	459
	Other Utilities	2200 Utilities	All, excluding EI21, EI22, SU30, SU40, SM01	147
	Wind and Solar	All Industry	SU60 Wind and solar	111
	Non-FF Power Plants (35.7%)		see Power Plants (FF)	533
	Total Energy, 2012			**4,472**

Table 35: Depreciated value for the U.S. energy sector, based on the 2013 BEA FAA Detailed Fixed Asset Tables for Non-Residential Fixed Assets and using the methodology developed for this work. **Top**: Asset categories related to fossil fuel use. Coal mines and railroad equipment are assigned a 40% share of its category based on industry revenue, and coal railroad tracks a 35% share based on ton-miles carried. As discussed in text, oil and gas extraction is likely overvalued by the BEA's price adjustment assumptions. The power plant category (which excludes wind and solar) is largely (72%) asset code "SU30 Electric", but includes other asset codes, e.g. we assume that "EI21 Steam engines" corresponds to steam turbines used to generate electricity. The BEA tables do not allow distinguishing fossil from non-fossil power plants. We assign the "fossil" group a 64.3% share based on our physical inventory (see text for detals); the remaining 35.7% share would then be predominantly nuclear and hydropower. **Bottom**: Asset categories not exclusive to fossil fuel use, which collectively total $1.25 T. This group includes 35.7% of power plants other than wind and solar. Note that throughout the table, in the description of asset items excluded from particular categories, we omit for convenience "SU60 Wind and solar" and "EI60 Electric transmission and distribution", which are assigned exclusive same-name categories, and "SU50 Petroleum pipelines", which lies entirely within the Oil and Gas Pipelines. We do not include "EI11 Nuclear fuel" anywhere as this asset class involves nuclear fuel rods with a stated 4-year service life, too short to be considered as a long-lived asset.

Note that different releases of the BEA FAA database differ slightly. A 2018 release with net stock values in 2012 fixed costs [434, 435] produces a 2012 total energy sector valuation about 6% higher than that shown here, at $4.72 T. The difference is mostly in the non-fossil category: fossil-only infrastructure differs by less than 1% between versions, at $3.23 T in v2018 vs. $3.22 T in v2013. However, individual categories can vary more strongly, e.g. 2012 oil and gas extraction asset value is 11% higher in v2018 than in v2013, at $1.64 T instead of $1.47 T. See Section L.5 for further discussion and derivation of the final value used ($4.18 T), which is based on v2018 with some BEA price adjustments removed.

J.4. Details of inventory category matching

This section provides details below about the selection of BEA industry and asset codes included in the estimate of energy sector value in Table 35, and about their mapping to categories in our physical inventory. We select particular asset and industry combinations, so that not all assets are considered even within an energy-relevant industry. The detailed schema provides a more complete accounting, and allows separating fossil fuel-related assets from those not associated with fossil fuels.

Note that while industry codes are well documented by NAICS [433], asset types are defined internally by the BEA, and have no official documentation, complicating their interpretation. Our interpretation of BEA asset codes is informed by their similarity to those used in the Commerce Department's National Income and Product Accounts (NIPAs), and by conversation with and internal documents from BEA staff [433, 436–442]. In the discussion below, NAICS industry codes are written in brackets and asset types in quotes.

Domestic Oil and Gas Extraction – $1.5 Trillion. We match our oil and gas extraction category with all asset items in [2110 Oil and Gas Extraction] other than "ET40 Ships and Boats" and "SU50 Petroleum pipelines", which are assigned to other inventory categories (tankers and oil pipelines). We also count two asset items in [2130 Support Activities for Mining], "SM01 Petroleum and natural gas" and "SU40 Gas". This value is likely an overestimate because of the BEA's assumed price adjustments; see Section L.2.

Foreign Oil and Gas Extraction, Import Transportation – $17 Billion. While the BEA does not include foreign assets that we inventory under Foreign Oil and Gas Extraction, it does include some assets used in transporting foreign oil and gas. We assume "ET40 Ships and Boats" in [2110 Oil and Gas Extraction] represent oil tankers and LNG carriers. We do not include "ET40 Ships and Boats" from [2130 Support Activities for Mining], since these may serve purposes other than fossil fuel extraction.

Refineries, Processing Plants, and Oil and Gas Storage – $158 Billion. For the purposes of the BEA comparison, we evaluate refineries, processing plants, and oil and gas storage jointly. We book-keep all of [3240 Petroleum and Coal Products Manufacturing], which includes oil refineries and tank farms and also some functions not included in our physical inventory like asphalt product manufacture. These cannot be disaggregated given the coarse-grained BEA categories. If the BEA tables were finer-grained, we could also add the detailed NAICS industries related to construction, e.g. [237120 Oil and Gas Pipeline and Related Structures Construction], but in the actual coarse BEA tables, these assets are a subset of the broad parent category [2300 Construction]. In this case we can estimate the value of fossil-fuel-related construction by taking all items in [2300] with asset codes "SM01 Petroleum and Natural Gas" and "SU40 Gas". It is likely that some of this value properly belongs in Oil and Gas Pipelines, but cannot be disaggregated.

Oil and Gas Pipelines – $485 Billion. This category of our inventory includes all oil and natural gas transmission and gathering pipelines and natural gas distribution, and service pipelines. We identify three relevant groupings in the BEA FAA as making up this category:

- All assets in [4860 Pipeline Transportation]. We assume these correspond to oil and gas transmission pipelines. This category excludes the service and distribution pipelines that bring natural gas to consumers. The NAICS description for industry category [4860 Pipeline Transportation] includes the phrase "Pipeline transportation of natural gas from process plants to local distribution systems" and explicitly excludes service and distribution pipelines, stating that "establishments primarily engaged in providing natural gas to the end consumer [service pipelines] are classified in Industry 221210, Natural Gas Distribution" [433].
- Asset code "SU50 Petroleum Pipeline" across all other industries. We assume this corresponds to the oil gathering pipelines that connect oilfields to refineries and transportation portals.In the 2012 BEA, 83% of SU50 is in [4860 Pipeline Transportation], book-kept above and assumed to be transmission pipelines; the remaining 17% is book-kept here and is essentially all in [2110 Oil & Gas Extraction].

- Asset code "SU40 Gas" under [2210 Utilities]. We assume this corresponds to natural gas distribution main and service pipelines. The NAICS description suggests that gas distribution is included in [2210 Utilities] [433], and the majority of the value in SU40 (76%) falls into [2210].

We suspect that this accounting omits natural gas gathering pipelines, leaving them lumped into the Domestic Oil and Gas Extraction category as part of the BEA grouping "SU40 Gas" in [2110 Oil & Gas Extraction]. (That grouping comprises 11% of the value of asset code SU40.) We have insufficient information to further subdivide this grouping. This issue would not alter our total BEA asset value assessment, though it would slightly affect the comparison of pipeline asset values in the BEA vs. this work. "SU40 Gas" constitutes 3% of total structure and equipment values in [2110 Oil & Gas Extraction], 14% in [2200 Utilities], and 22% in [4860 Pipeline Transportation], whereas "SM01 Petroleum and Natural Gas" constitutes 84%, 0%, and 1%.

Gasoline Stations - $0. We do not evaluate gasoline stations, as these comprise only a minute portion of the generic BEA industry class [4400 Retail Trade] and cannot be readily separated from the much larger set of non-relevant assets.

Oil and Gas Other - $1.6 Billion. This category includes all of "SM01 Petroleum and natural gas" and "SU40 Gas"across those other industries not already included in the categories described above, a total of $785 million and $792 million, respectively.

Coal Extraction - $61 Billion. Coal mining equipment and infrastructure make up a part of the industry category [2120 Mining, Except Oil and Gas]. To assess their value, we first exclude those asset classes included elsewhere in this accounting ("SU50 Petroleum Pipeline", "SU 40 Gas", and "SM01 Petroleum and natural gas") and those associated with coal or ore transport ("ET50 Railroad equipment", "SU11 track replacement," and "SU50 Petroleum pipelines"), leaving only assets associated with extraction. Because the BEA FAA does not provide sufficient information to disaggregate assets used for coal mining from those used in mining metal and non-metal ores, we then approximate the value of coal-related assets by taking a 40% share of the remainder. The 40% share is based on the proportion of coal revenues as reported in statistics from the National Mining Association [432].

Coal Transportation, Rail - $69 Billion. In our physical inventory, we assess infrastructure costs for coal rail shipment as 35% of all Class I freight railroad asset value, with the 35% factor derived from the coal share of all rail freight by ton-mile (Appendix F.2). We replicate this procedure for the BEA accounts. We define freight rail as all assets with code "SU12 track replacement", nearly all of whose value (99.98%) is in industry [4820 Rail transportation]. (This asset code accounts for half of value in [4820].) This value would include rail lines devoted to passengers, but these make up a negligible share of railroad infrastructure. We do not consider "SU11 Other railroad" since it may include transit structures such as train stations. For completeness, we also include the comparatively minor asset value in code "ET50 Railroad equipment" when it falls under industry [2120 Mining, Except Oil and Gas] (∼$0.2 B). Since [2120] contains metal ore and non-metal ore mining alongside coal, we apply a 40% share as was done for *Coal Extraction.*

Power Plants, fossil fueled – $756 Billion. It is not possible to disaggregate fossil- and non-fossil power plants from BEA information alone. To apportion this category between fossil- and non-fossil power plants, we use our physical inventory to derive in Appendix K a 64.3% share for fossil plants of total depreciated total power plant value. Our physical inventory counts alll power plants, both those that provide electrical power distributed by utilities and the much smaller number serving individual private entities (e.g. industrial combined heat and power). However, we cannot take the entire BEA category [2210 Utilities], since this category includes not only electricity generators but also assets such as power transmission and distribution. We therefore construct the power plants category from a variety of industry and asset code groupings. We include, in order of importance:

- *72% of total* – All of the BEA asset code "SU30 Electric", which predominantly describes power plants. This matching is supported by the NAICS industry description [433] and the NIPA reference

document [439]. 98% of "SU30 Electric" falls in [2210 Utilities], and the remaining 2% may represent private/industry electricity generation.

- *21% of total* – All of the line item "Power" under Section 7: Government Assets. This line item covers public-sector electricity generation, including municipal utilities and hydropower operated by federal agencies and corporations, e.g. the Bonneville Power Administration for the Columbia River and the Tennesse Valley Authority for parts of the Southeast. The category necesssarily includes some electricity transmission and distribution by public utilities that should be excluded, but cannot be disaggregated further. Its 21% share of the Power Plants category matches estimates of the share of U.S. generation by government utilities [e.g., 443, 444].

- *6% of total* – The asset code "E121 Steam engines" across all industries. The category name "steam engines" almost certainly refers to steam turbines used to generate electricity. 76% of their value falls in [2210 Utilities].

- *0.2% of total* – The asset code "E122 Internal combustion engines" when it falls under [2210 Utilities]. This grouping likely represents oil and diesel generators.

Power Plants, non-fossil – $533 Billion. As per the procedure above, we assign $(1 - 0.643) = 35.7\%$ of the total BEA asset value for power plants to the non-fossil category, which includes nuclear, hydropower, and biofuel-powered electricity generation. Solar and wind facilities are specified separately in the BEA FAA.

Solar and Wind – $111 Billion. We take all of "SU60 Wind and solar" to be wind turbines and solar photovoltaic or thermal electricity generation facilities. Adding this total to the non-fossil power plants category above gives a total of $729 B for non-fossil power generation.

Electricity Transmission and Distribution – $459 Billion. We take all of "EI60 Electric transmission and distribution". This value is quite small – only 16% of our estimated replacement value for the grid – and is certainly an underestimate, since many transmission and distribution assets will be erroneously grouped into *Power Plants* in our scheme. As discussed above, the detailed BEA FAA tables describe only private assets, and assets owned by federal, state, or municipal utilities (∼$250 B) are not disaggregated and are assigned entirely to *Power Plants*. Non-private entities are estimated to deliver electricity to a quarter of U.S. customers [445], and own a disproportionate share of transmission lines. In the U.S. Northwest, for example, around 80% of high-voltage transmission is owned by the Bonneville Power Administration, a part of the federal Department of Energy [446, 447]. Even within private electricity-related assets, the BEA partitioning between electric generation and transmission and distribution is not particularly clear, and it is likely that some of the nearly $850 B in the asset category "SU30 Electric" is transmission and distribution. Finally, as discussed in Section L.2, the BEA's price adjustment scheme may be undervaluing early investments in transmission and distribution.

Other Utilities – $147 Billion. This category accounts for all asset items in [2200 Utilities] that were not already classified in other categories above. That is, we take the total of [2200 Utilities] minus "EI21 Steam engines, "E122 Internal combustion engines", "SU30 Electric", "SU40 Gas", and "SM01 Petroleum and natural gas",[55] as well as the three asset categories full accounted for elsewhere –"SU60 Wind and solar", "EI60 Electric transmission and distribution", and "SU50 Petroleum pipelines"– and the fully excluded "EI11 Nuclear fuel". Note that "Other Utilities" may include some asset items not associated with electricity production.

[55] We leave that part of "EO50 Mining and oilfield machinery" under [2200 Utilities] in *Other Utilities* rather than assigning it to "Oil and Gas Extraction", but its asset value is small, only 7% of *Other Utilities* and 1% of *Oil and Gas Extraction*

K. Age structure and comparison of depreciated value with the BEA FAA

To compare asset values in our physical inventory to those in the Bureau of Economic Analysis Fixed Asset Account (BEA FAA) [428], we construct their depreciated values. Depreciation requires knowledge of asset age structure, an assumption of service life, and a depreciation scheme. Age structure information is available from official and well-validated databases for extant wells, pipelines, and power plants, which comprise over 80% of fossil-exclusive asset value in our inventory. Age structure information for other categories is more limited and we do not attempt to depreciate them. Using the BEA depreciation scheme, wells, pipelines, and power plants in our inventory retain 48%, 47%, and 51% of their upfront values, respectively.

Our depreciated values are in close agreement with those of equivalent categories in the BEA, validating both our physical inventory and the methodology we use to define the energy sector in BEA FAA data (Figure 30). The final sums match within 10% for pipelines, 5% for power plants, and 12% for oil and gas wells, all within our estimated uncertainty range. (See e.g. Figure 4.) Note that for oil and gas wells we have omitted the BEA historical price adjustment, which appears erroneously high and biases their valuation of older wells; see Section L.5 for extensive discussion. To do this we must use the 2018 rather than the 2013 release of the BEA FAA; oil and gas extraction totals in the two releases differ by 11%. Depreciated oil and gas well asset value is $0.9T in our physical inventory, $1.1T in the v2018 BEA FAA without price adjustment, and $1.6T in the v2018 BEA FAA with price adjustment. The remainder of this section describes the construction of depreciated estimates in detail: the age structures of energy assets, the depreciation scheme, and details for individual asset classes.

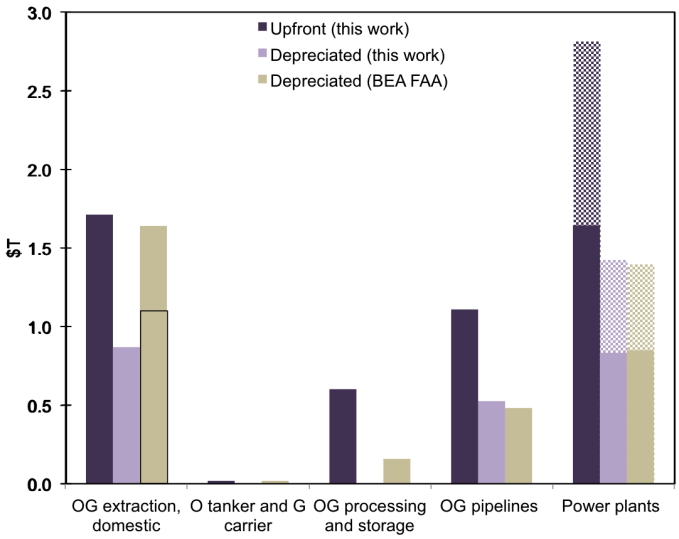

Figure 30: Comparison of our physical inventory values of upfront costs of domestic energy assets (dark purple) and their corresponding depreciated values (light purple) with the independently derived BEA FAA depreciated values (tan). For power plants, we show both all power plants (shaded) and fossil-only (solid). Because the BEA FAA provides no means of distinguishing fossil- from non-fossil power plants, we simply apply the breakdown from our inventory (64.3% fossil, 35.7% non-fossil) to BEA values. For oil & gas, we show BEA net stock totals with (tan bar) and without (solid outline) use of their historical price adjustment, which appears erroneously high. In both cases we use the v2018 release of the BEA FAA; all other asset categories are defined using v2013. The non-price-adjusted oil & gas value is constructed from the v2018 historical BEA investment timeseries, adjusting for inflation only; see Section L.5 for details. For informational purposes, we also include two asset categories where depreciation of our physical inventory was not possible, tankers/gas carriers/LNG terminals, and refineries/processing/storage. The low BEA depreciated value for processing and storage likely reflects that fact that U.S. refineries are typically many decades old [216]. Our physical inventory values match the BEA extremely well, suggesting our methodology is sound.

K.1. Age structure of energy sector assets

We construct age structures for oil and gas extraction, pipelines, and power plants from the same well-established sources used for asset counts. Oil and gas well ages are given in the DrillingInfo 2018 database for onshore wells [1] and the Bureau of Ocean Energy Management database for offshore wells [2, 48]. Pipeline mileage is reported by decade in the PHMSA (Pipeline and Hazardous Materials Safety Administration) database [4–6]. For power plants, first operation dates for individual plants are provided by the EIA [8]. Multiplying the age structure (number of wells, nameplate capacity or pipeline mileage per year or decade) by our assumed upfront costs produces an age structure of asset value (which should be somewhat lower than true investment spending, since it omits assets retired before 2012). Figure 31 shows the resulting age structure for fossil-only infrastructure, and Figure 32 shows all power plants, inclusive of non-fossil ones (and Figure 28 in Section H shows oil power plants only) Figures 33–35 shows wells and pipelines.

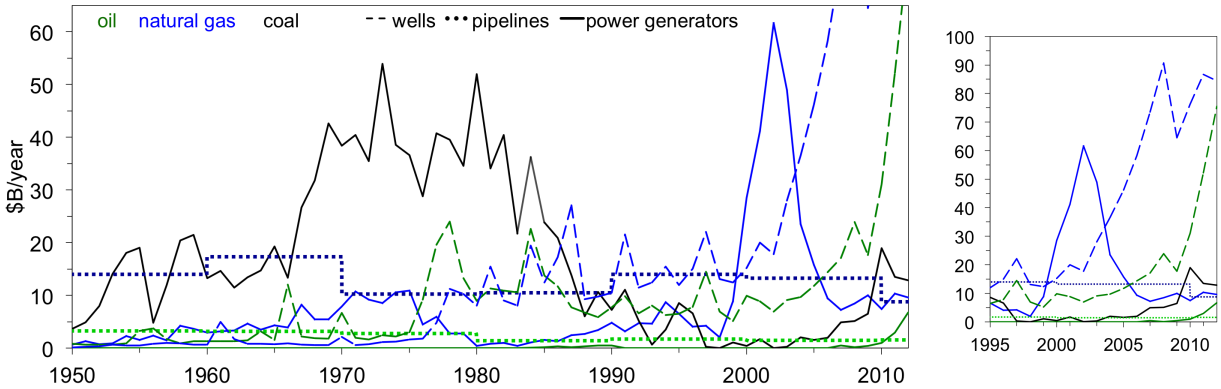

Figure 31: Non-depreciated value of fossil-exclusive energy infrastructure added each year that is still operational in 2012, for power plants (solid), pipelines (dotted), and wells (dashed), separated for oil (green), gas (blue) and coal (black). Left: 1950-2012; Right: expanded view of 1995-2012 to better show wells. Age structure sources are described in this section. Power plant and well ages are annual; pipelines are incremented by decade. Around 7% of pipeline mileage (5% of book value) has no listed construction date and is not shown here. See Figures 32–35 and Table 37 for details and mean construction years.

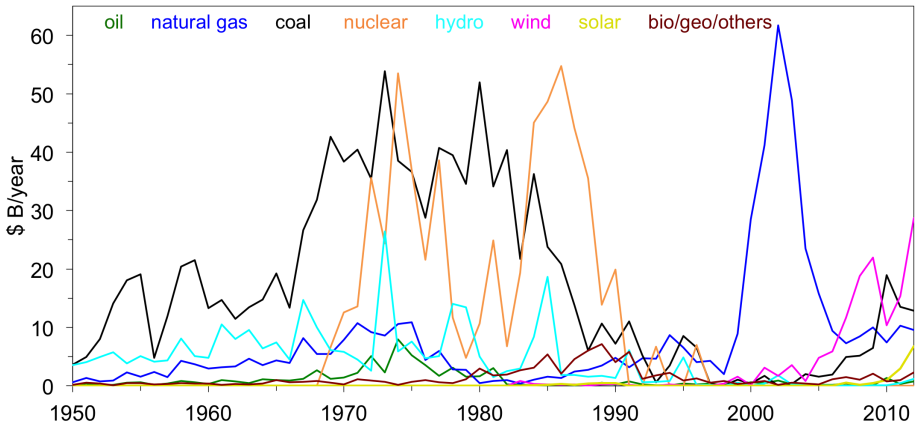

Figure 32: Non-depreciated value of all power plants added each year that that are still operational in 2012, now including both fossil and non-fossil power plants, from EIA compiled data [8]. While wind and solar facilities are young, the capacity-weighted average construction year of rest of the 2012 operating electricity generation fleet is 1976 for coal and oil, 1994 for gas, 1981 for nuclear, and 1966 for hydro. See Table 37.

Many features of the asset value age structure in Figures 31 and 32 can be related to well-understood factors in the energy sector. **Power plants** show especially varying age structures. Investment in oil- and gas-fired coal plants declined rapidly after the OPEC oil crisis, and the 1978 Power Plant and Industrial Fuel Use Act effectively barred their construction until its repeal in 1987 [448–450]. (See Figure 28 and 32.) Investment in coal plants also declined in the 1980's, likely because of tightening environmental regulations, and never recovered. The capacity-weighted mean age of operating coal plants in the U.S. in 2012 is 36 years

[8]. For nuclear plants, the 1979 Three Mile Island accident is reflected in the nuclear plant age structure as a dip in completions from 1979 to the early 1980's, as safety regulations were reviewed, and then an end to nuclear construction in the late 1980's as ongoing projects were completed but no further permits were issued. The combination of these trends produced a near-total lack of generation capacity additions in the 1990s and an eventual crisis as reserve margins dropped unsafely low, followed by a temporary boom in gas construction as utilities scrambled to compensate for a decade of under-investment [448–450].

For **oil and gas extraction**, The book value of extant domestic oil and gas wells is heavily weighted to those drilled after the fracking revolution began in the early 2000s (Figure 31). This structure is not produced by well retirements; the age structure of the conventional wells (which dominate well counts) still producing in 2012 is relatively flat for nearly 40 years (Figures 33–**??**). Instead, the number of wells drilled increases in the early 2000s, and most importantly, these newer wells involve expensive modern technologies. Mean dates of first production in our inventory are 1992 for conventional vertical wells and shallow-water offshore wells, but only 2007 for horizontal wells. (Fracked oil wells are younger than those of gas, consistent with assumptions throughout this work.) For complete values see Table 5 in Section B. By 2012, horizontal wells make up the 2nd-largest category of new wells drilled in the U.S., and spending on oil and gas extraction exceeds that on any other category of U.S. energy infrastructure.

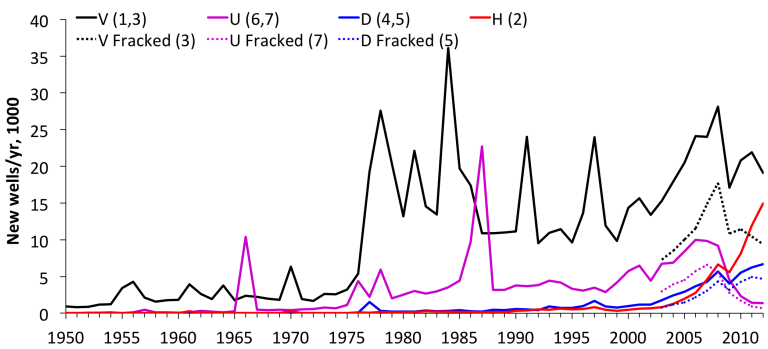

Figure 33: Number of onshore wells completed each year that are still producing in 2012, from DrillingInfo 2018 [1]. Colors indicate drilling direction and solid/dashed lines indicating unfracked/fracked wells in the vertical, directional, and unknown categories. All horizontal wells are assumed fracked. Because recent fracked wells are more expensiver, mean ages of first production for all wells is 1998 if weighted by value but only 1993 if weighted by well count.

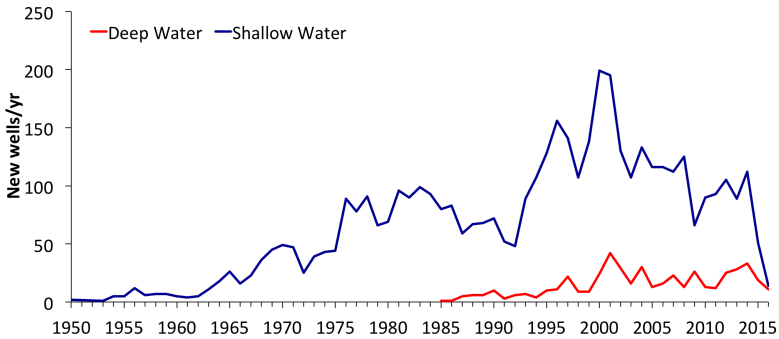

Figure 34: Number of offshore wells completed each year that are still operational in 2017, from BOEM 2017 [2].

For **pipelines**, assets in our inventory tend to be old. Pipeline construction boomed after the end of World War II, and most of those early pipelines remain in use. For both oil and gas transmission pipelines, the decades that contribute the most total mileage to U.S. pipelines operational in 2012 are the 1950s and 1960s (Figure 35). The mileage-weighted mean construction year for 2012 U.S. pipelines is 1981 for gas pipelines and 1971 for oil, i.e. average ages of 30 and 40 years, respectively. While the fracking revolution has led to acceleration of pipeline construction, especially for oil, these changes are not reflected in a 2012 inventory (Figure 35). Note that of PHMSA pipelines operational in 2012, about ∼4% by mileage (7% of upfront value) are listed as pre-1940s and not shown in Figure 35, along with the ∼7% by mileage (9% of total upfront values) that have no listed date in the PHMSA database.

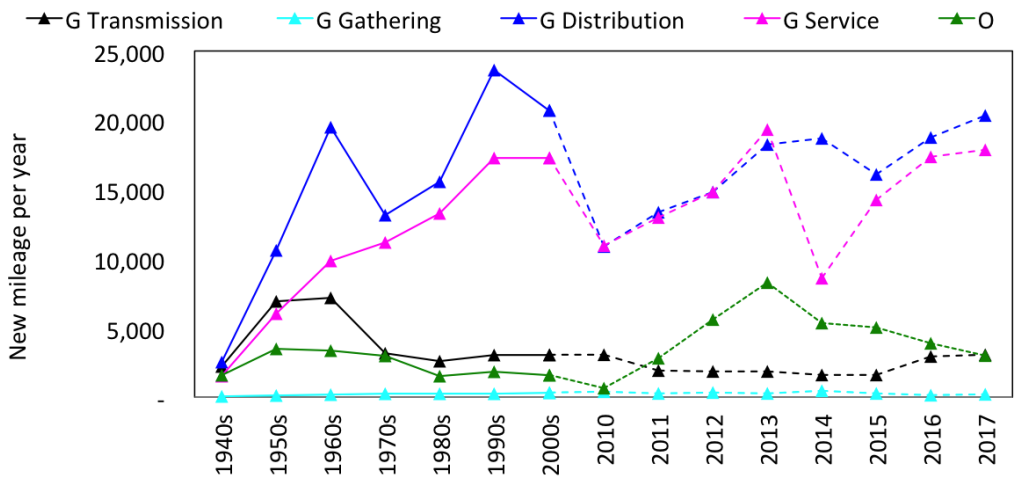

Figure 35: Average mileage per year of oil and gas pipelines added, of those still in operationl as of 2012 (solid lines), by decade, from the 2018 releases of the PHMSA Annual Hazardous Liquid Pipelines Database and Annual Gas Transmission, Gathering, Distribution, and Service Pipelines Database [4–6]. Data is shown by decade since PHMSA provides pipeline ages only by decade. However, PHMSA also provides individual-year datasheets for 2010-2018, so for comparison we also show estimates of yearly pipeline additions over this period determined by subtraction (dashed lines). (We assume no 2010s pipelines are already replaced.) Pipeline construction appears depressed around 2010, likely because of the Great Recession, but rebounds in subsequent years. By the mid-2010s, oil pipeline construction may be at a historic high, but these new additions are not reflected in the 2012 inventory. Note that service pipelines are reported by number rather than by mileage; we estimate mileage assuming that length per service pipeline is constant. See Section D for details.

K.2. Depreciation scheme

To allow meaningful comparison with BEA values, we depreciate the energy inventory upfront values using the BEA methods for similar assets [441]. The BEA uses geometric depreciation, which allows assets to retain non-zero value even after the end of their service life. BEA assumptions for oil and gas extraction, pipelines, and power plant categories are shown in Table 36, and resulting depreciation profiles in Figure 36. Note that the BEA depreciation assumptions are not matched uniquely with BEA asset codes. Furthermore, individual categories in our physical inventory may contain assets assumed by the BEA to have different service lives. In these cases we use the assumed parameters of the dominant asset.

Type of BEA FAA asset	**BEA service life, years**	**Depreciation rate**	**Category, this work**
Mining exploration, shafts, and wells: petroleum and natural gas	12, 16 (after / before 1973)	0.0751, 0.0563	Oil and gas extraction (domestic)
Petroleum pipeline	40	0.0237	Oil and gas pipelines
Gas	40	0.0237	
Electric light and power	45, 40 (after / before 1946)	0.0211, 0.0237	Power plants

Table 36: BEA FAA reported service lives and depreciation rates, for those asset categories where we have reasonable age structure information in the physical inventory. Values are from two BEA sources: the Fixed Asset Account methodology guides [441] and the NIPA methodology report *The Measurement of Depreciation in the U.S. National Income and Product Accounts* [426]. We depreciate according to BEA procedure for the dominant asset type, shown in this table. The "Power plants" category also encompasses "Steam engines and turbines" at 32 years and "Internal combustion engines" at 8 years, and "Oil and gas extraction" encompasses "Mining & oilfield material" at 11 years.

While we use the BEA assumed service lifetimes for the purpose of comparison, note the age structures shown above imply that many energy-sector assets remain in use for considerably longer time. At least

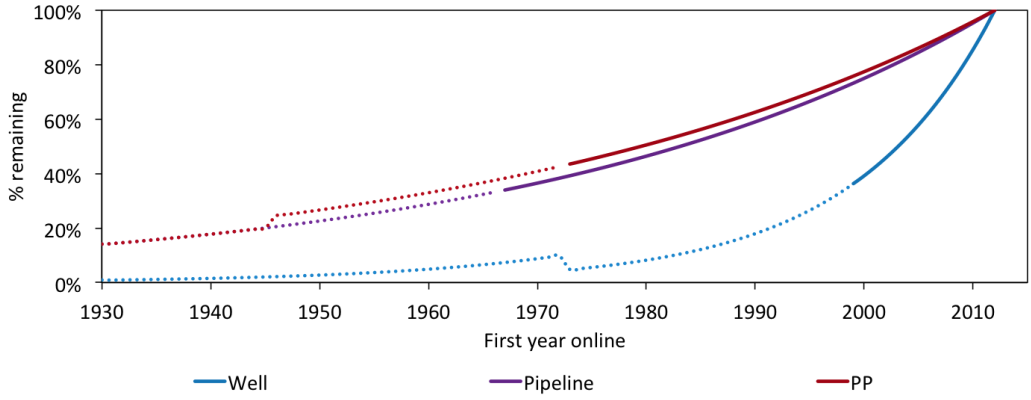

Figure 36: Depreciation profile for wells, pipelines, and power plants (PP), constructed using values in Table 36 (taken from [441] and [426]). The transition from solid to dashed marks the BEA FAA assumed service life. For all categories, assets retain approximately 40% of their original value at that age. Kinks in lines result when the BEA assigns different lifetimes and so depreciation rates for assets constructed before or after a threshold year. Wells developed before 1973 have a longer assumed life (16 vs. 12 years) in the BEA methodology, and power plants built before 1946 a shorter one (40 vs. 45 years).

13% of power plants, 38% of pipelines, and 42% of wells (weighted by capacity/mileage/number well count) operational in 2012 have passed their BEA stipulated service lives of 45, 40, and 12 years, respectively. For this reason we generate separate, more realistic estimates of asset service lives in Section M.

Details for individual categories

Oil and gas wells – $869 B, 51% of upfront value

For onshore wells, we take the first production date in the DrillingInfo 2018 database [1] as the construction year for age structure and depreciation calculations; these dates are shown in Figure 33. Note that using a service life of 20 years for wells would increase the depreciated value of the U.S. well fleet to 63% of its book value from 51% in the BEA approach.

Oil and Gas Pipelines – $526 B, 47% of upfront value

Since PHMSA reports pipeline initial operation years only by decade, we take the mid-point of each decade for the purposes of depreciation (e.g. all pipelines in the bin of 1970-1979 have an assumed first year of operation of 1975).The maximum uncertainty due to the coarse date bins is about 10%: we recalculate values using the first and last year of each decade (e.g. 1970 and 1979) and derive $469 B and $578 B.

Power plants – $892 B fossil, $496 B non-fossil (excl. solar/wind), 54% and 53% of upfront value

Using the BEA FAA standard service life of 40/45 years (before and after 1946), we derive an estimated depreciated value of $1388 billion for power plants excluding solar and wind, of which $892 billion are fossil-fueled and $496 billion are non-fossil; the latter category is dominated by nuclear and hydropower. Because the BEA does not distinguish power plants by fuel type (other than solar and wind, which have their own asset code SU60), we apply this breakdown to the BEA net stock values in Figure 30. That is, we assume that fossil-fueled power plants make up 892/(496+892)= 64.3% of total value in the BEA power plant category. This breakdown is also used in Section J. Note that the simple BEA depreciation scheme can produce misleading values if applied to individual subsets of power plants that in reality have different service lives. The upfront value-weighted mean age of short-lived gas plants in our inventory is only 20 years while that of long-lived hydro plants is 46 years. In the BEA scheme, gas power plants operational in 2012 appear to retain 69% of their upfront value and hydro plants only 39%. See Section M for more accurate estimation of service lives.

L. Investment in energy assets

Information on annual investment in energy infrastructure is a useful complement to our physical inventory. Comparing asset values to investment gives a rough estimate of the capital turnover rate, which sets the timescale for a plausible energy transition. For individual sectors, comparing the apparent capital turnover rate to asset lifespans allows identifying areas experiencing growth or stagnation. Investment information also provides a variety of consistency checks on our physical inventory, allowing cross-validation between multiple sources. Finally, investment information can be used construct a timeseries of net stock in energy-related assets, and thus to determine the evolution of capital intensiveness of the U.S. energy sector.

We construct a composite timeseries of annual investment in energy infrastructure from 1994–2016, shown in Figure 37, from several sources described in detail below. In 2012, total investment in the U.S. energy sector (inclusive of U.S.-serving foreign oil and gas) is **$400 B**, implying a turnover time of 26 years were the overall energy system in steady-state (which it is not, and the steady-state value is almost certainly longer). Investment in renewable electricity generation (largely wind) makes up ∼25% of 2012 capital investment in power plants ($21 B vs. $62 B for all other power plants), but accounts for only ∼5% of total U.S. energy-sector infrastructure investment.

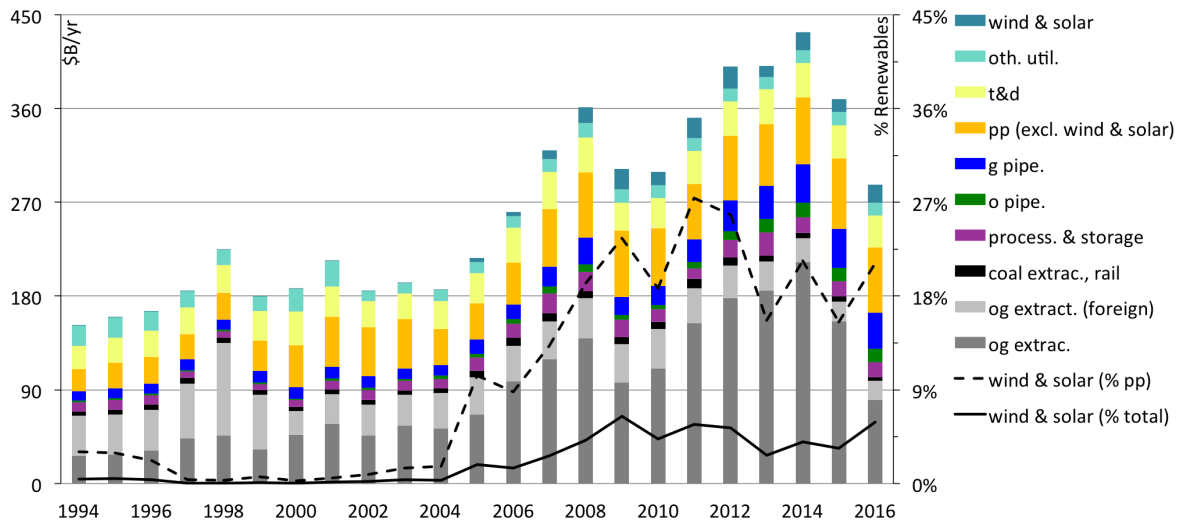

Figure 37: Historical investment in long-lived assets in the U.S. energy sector from 1994-2016 (left axis) and proprtion of power plant investment that is wind and solar (right axis). In 2012, wind and solar account for essentially all renewables investment, since no new nuclear or hydroelectric power plants are being built (Figure 32). All data are historical costs, inflation-adjusted to 2012 dollars with no price adjustment other than on foreign oil. Domestic data are from the BEA other than three categories from ACES: domestic oil and gas extraction (1% higher than BEA in 2012), pipelines (50% higher), and coal extraction (50% smaller; this category is tiny). Foreign extraction values are estimated using global oil and gas extraction investment from the IEA and flows from the EIA; see text for details. Domestic oil and gas extraction investment rises steeply after ∼2004 with deployment of modern fracking. By 2012, the U.S. accounts for ∼25% of global oil and gas investment ($178 B out of ∼$700 B) even though U.S. production is only 13% of the global total (17 M out of 130 M boe per day).

Individual asset categories are not in steady-state. Domestic oil and gas extraction is building up, as noted in Section K, with annual investment more than doubling in real dollars between 2003–2012. This non-steady-state condition is manifested an abnormally short apparent turnover time of 10 years (2012 investment of $178 B vs. replacement value $1.7 T). Investment in the electrical grid appears smaller than its steady-state value, but the discrepancy may be due in part to mis-labeling of assets. (See discussion in Section L.5.)

In the following, Section L.1 describes the composite timeseries, Sections L.2–L.3 provide details on four different sources for investment estimates, and Section L.4 cross-compares them. Finally, in Section L.5, we use investment information to construct a timeseries of net stock in energy-related assets from 1949.

L.1. Composite investment timeseries

The primary dataset for our composite investment timeseries is the BEA Fixed Asset Accounts, which gather historical U.S. investment data from multiple sources. (The BEA combines investment estimates with assumed depreciation rates to construct the net stock estimates discussed in Sections J and K.) While the BEA asset tables cover the entire domestic energy sector, we replace BEA estimates in three categories – domestic oil and gas, pipelines, and coal extraction – with estimates from the Census Bureau's Annual Capital Expenditure Survey (ACES). The sources are not fully independent, since ACES is used by the BEA in compiling their tables, but ACES provides finer-grained categories. (See Sections L.2–L.3 for details.) Values are inflation-adjusted to 2012 dollars without price adjustments. In 2012, oil and gas extraction investment in ACES is within 1% (-$2 B) of the BEA-derived value, but pipeline investment is 50% higher (+$13 B) and coal extraction 50% lower (-$4 B) than BEA-derived estimates.

Foreign oil and gas extraction. Global upstream oil and gas infrastructure is entangled with the U.S. supply chain, since the United States has imported about 1/10th of global oil production over the past several decades [37, 39, 41, 78, 451, 452]. We estimate investment for foreign infrastructure serving the U.S. as a share of global upstream oil and gas investment. That is, we first construct a measure of non-U.S. investment, and then apply a factor that represents the share of global non-U.S. oil and gas production that become net imports to the U.S. (10–13% over the 1994-2016 time period). For production and imports, we use EIA data [40, 78, 129, 329, 451, 452],[56], and for non-U.S. investment, we subtract U.S. investment from ACES from global values from the IEA World Energy Investment Outlook [453, 454]).

Unfortunately, IEA global oil and gas investment values cannot be made entirely consistent with U.S. investments, nor self-consistent across the full timeseries. Data from 2000 onward are provided by the 2014 World Energy Investment Outlook [453] as fixed 2012 costs, adjusted by the IEA's Upstream Investment Cost Index (UICI) based on assumptions about inflation and price increases for individual countries. Data from 1994–2000 are provided by the 2002 report [454] as global historical costs, without price or inflation adjustment. To ensure some historical compatibility we roughly adjust these earlier values based on the crude oil purchase price [361], which is often compared to the UICI as a measure of combined inflation and cost fluctuations [455–458]. The method does produce a discontinuity at 2000 and likely overvalues earlier foreign oil and gas values relative to other investment categories in Figure 37.

L.2. Bureau of Economic Analysis Fixed Asset Account (BEA FAA)

The Bureau of Economic Analysis Fixed Asset Accounts (BEA FAA) *Detailed Asset Table – Nonresidential Detailed Estimates* [434] provides estimates of both depreciated net capital stock and annual investment in U.S. assets for each year since 1949. Because both estimates are categorized identically by NAICS industry code and BEA asset code, we can use the selection scheme developed for net stock in Section J (described in Table 35) to match investment categories to our physical inventory and produce a timeseries of annual energy sector investment. In Figure 38 we show the resulting timeseries in two reporting conventions: as historical costs adjusted by inflation to 2012 dollars, and as fixed costs, i.e. inflation- and price-adjusted to a benchmark year, in this case 2012. For private-sector non-residential investments, both are provided in the 2018 BEA release [434, 435].[57] Government power investment is reported in the BEA FAA only as historical costs, but we estimate a fixed-cost version as in Section J. In both investment and net stock timeseries, government power makes up ∼15-20% of total value in the power plant category.

[56] To avoid double-counting the liquid by-products of natural gas production, we use only dry gas data, and then count as petroleum production both crude oil and natural gas liquids, as well as refinery gains and other associated fuels (e.g., renewables and oxygenate plant production) as defined in Monthly Energy Review [Table 3.1 329]. It is not possible to separate out renewables (biofuels), but these make up only a tiny fraction (∼5%) of total petroleum production.

[57] The BEA reporting convention for investment differs from that for net stock. Net stock values are given in "current" costs, i.e. inflation- and price-adjusted to each individual reporting year. See Section J,

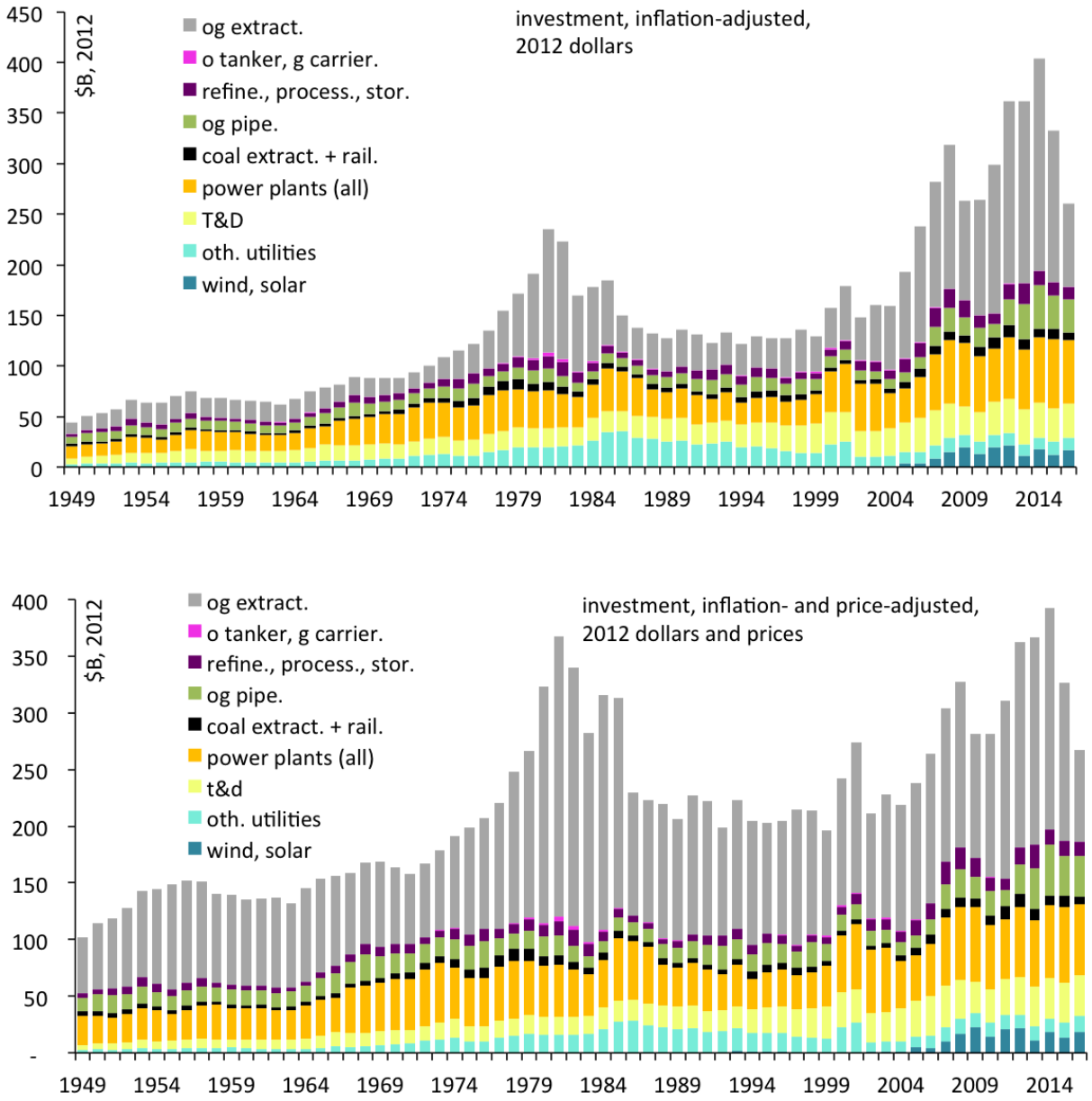

Figure 38: Annual investment in the U.S. energy sector from 1949–2016 in historical (top) and fixed (bottom) costs, from the 2018 BEA FAA [434]. Fixed costs are inflation- and price-adjusted by the BEA to the benchmark year of 2012. We adjust historical investment data to 2012 dollars through a gross domestic product deflator. Categories are as defined in Section J Table 35, except for "og extract." which here includes the category "og other". We plot categories in reverse order from Figure 38 to isolate the large volatility in oil and gas extraction investment, which largely tracks oil prices (see also Figure 28). Oil prices spiked in the early 1980s at over $100/bbl, sank to ∼$30/bbl during the 1990s, rose above $100/bbl again by 2008, after which they remained high (with a slight dip during the Great Recession) until about 2014 when they began a steep decline, likely due to both globally slowing economic growth and increasing supply from fracked oil [361]. By contrast, investment in the electric sector grows steadily over time, rising fourfold in fixed costs from 1949–2016, from $37 to $130 B/year. Comparing top and bottom panels shows the effect of BEA price adjustments. For oil and gas extraction, adjustments raise investment values by a factor of 3–5 in most years pre-2000; for transmission and distribution they reduce values in early years. Wind and solar investment (dark green) begins as early as 1993, but does not exceed $5B/year until 2004. Since 2004, wind and solar investment has risen rapidly and as of 2012 makes up ∼25% of all power plant investment. This rise is not accompanied by a concurrent decrease in investment in other generation technologies, possibly because larger total investment is needed to make up for recent retirements of coal-fired plants [8, 459]. Fluctuations in wind and solar investment are driven in part by periodic lapses in tax credits for renewables [459, 460].

The methodology behind the BEA price adjustments is not well documented, but Figure 38 makes it clear that this adjustment disproportionately affects oil and gas extraction. For oil and gas extraction, the BEA price adjustment raises investment values in early years by over a factor of four, significantly larger than the effect of adjustments in any other energy-sector category (Figure 39). The adjustments have the effect of flattening out past cycles of oil and gas investment, reducing the contrast between the two major investment booms (late 1970s-early 1980s and the 2000s fracking era) and their surrounding years.

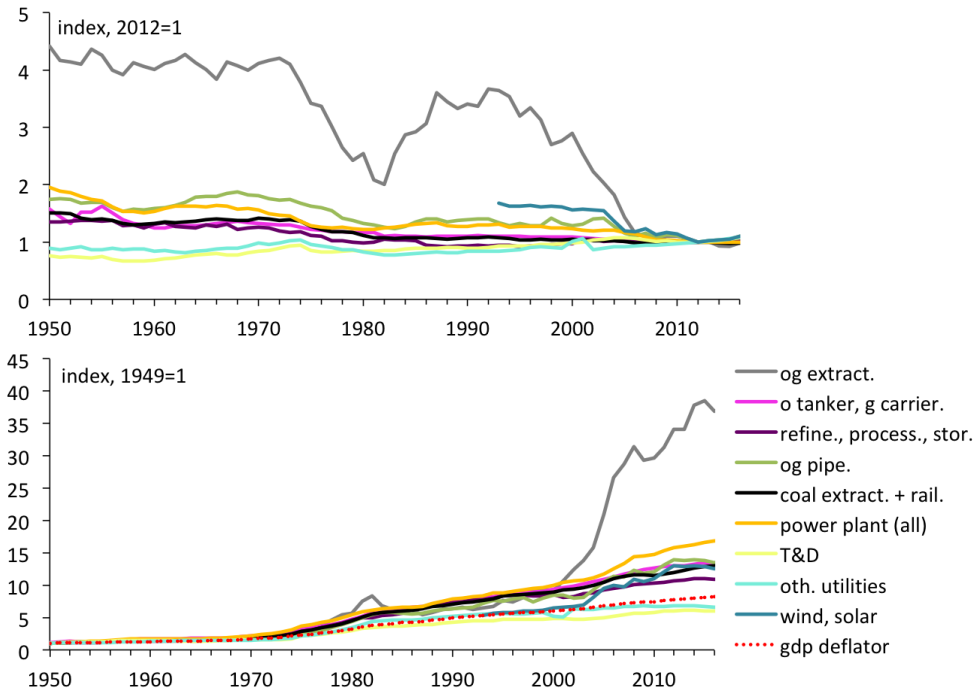

Figure 39: **Top:** Asset price index adjustments assumed by the BEA, determined by dividing BEA reported fixed cost investment in 2012 dollars for each category by reported nominal cost investment manually inflation-adjusted to 2012 dollars. For most energy-sector asset categories, price index adjustments raise the fixed-cost investment in any year by only around $\times$ 1.5 at most; for oil and gas extraction, the adjustment is over $\times$ 4 in many years. **Bottom:** Normalized BEA asset price and inflation adjustments, determined by dividing for each category BEA reported fixed cost investment in 2012 dollars by reported nominal cost investment, and then normalizing to 1949 values. We show the GDP deflator for reference (red dashed line). The BEA fixed cost timeseries effectively assumes that the fracking era involved a price change of nearly a factor of three, substantially larger than the effect of inflation. Because wind and solar investment data is not available until 1993, we display adjustments comparably by normalizing so that the 1993 value for wind and solar equals the 1993 value of the GDP deflator.

For a variety of reasons, the oil and gas adjustments seem distorting to an asset value analysis. First, their inclusion would mean that assessed replacement value of the oil and gas sector relative to other parts of the energy system becomes highly dependent on the choice of benchmark year. Using a benchmark year of 2000 rather than 2012 would significantly reduce the importance of oil and gas infrastructure. Throughout this analysis, we have attempted to avoid distortions that reflect temporary conditions rather than true long-term trends. Second, the BEA assumed rise in drilling prices between 2000–2012 is so steep that it triggers some concen that it may reflect a failure to account for changing well technologies. That is, the BEA adjustment may be effectively assigning a per-well cost appropriate for the technology mix of 2012 to earlier, simpler, conventional wells. For these reasons, we omit BEA price adjustments for oil and gas extraction in our analysis, but we attempt whenever possible to make clear the impact of this choice.

We retain the BEA price adjustments for transmission and distribution and "other utilities", although these may produce bias in the opposite direction, undervaluing early investments in the electrical grid. The BEA adjustments assume a long-term price decrease for transmission and distribution that is unique among energy-sector asset categories and is seemingly contradicted by recent trends. (See Section I.)

L.3. Other sources: ACES, EEI, and BNEF

The U.S. Census Bureau *Annual Capital Expenditure Survey (ACES)* [461] reports annual U.S. domestic capital investments since 1994 in historical costs. ACES is one of the sources used by the BEA, but uses more detailed categories. ACES data from 1998 onwards are readily mapped to BEA values as they are classified by NAICS code, similar to the NAICS industry categorizations used in the BEA FAA. Prior to 1998, ACES was classified by Standard Industrial Classification (SIC) code. To make 1994-1997 comparable, we match categories based on the NAICS-to-SIC concordance table provided by the Census Bureau [462]. For the following categories, we use in Figure 37 values from ACES rather than the BEA:

- Oil & gas extraction: *[2111 Oil and gas extraction]*, and *[213111/213112, Support activities for oil and gas operations]*
- Coal extraction: *[2121 Coal mining]*
- Oil pipelines: *[4861, 4869 Pipeline transportation of crude oil, refined petroleum, & misc. products, excl. natural gas]*
- Gas pipelines: *[4862 Pipeline transportation of natural gas]* and *[2212 Natural gas distribution]*

For 1994–1998 ACES data, we use the following matchings from the the NAICS to SIC concordance table. The matching is not one to one; for example, the SIC category [493 Combination electric and gas, and other services] covers both natural gas distribution (pipelines) and power generation.

- Oil and gas domestic extraction: *[131, 132 Mining – Crude petroleum, natural gas, and natural gas liquids]*, and *[138 Mining – Oil and gas field services]*[58]
- Coal extraction: *[12 Mining – Coal mining]*
- Oil pipelines: *[46 Transportation – Pipelines (except natural gas)]*
- Gas pipelines: *[492 Gas, water, and other utilities – Gas production and distribution]*[59]
- Electric sector: *[491 Electric and gas services – Electric power generation, transmission, and distribution]* and *[493 Electric and gas services – Combination electric and gas, and other services]*. Inclusion of the latter category may overlap with natural gas distribution pipelines but we suspect the effect is minor [462]

The *Edison Electric Institute (EEI)*, a trade association representing investor-owned electric companies, tracks investments in the electric sector, with separate estimates for transmission (t) and distribution (d). We infer power plant investment by subtracting t&d from the total. EEI data is restricted to investor-owned companies, making it comparable to ACES or to BEA estimates without inclusion of "government power". EEI investment data are generally reported in the EEI Financial Review (FR) annual series [463–470] but we take some values from other sources, including data published in graphs and extracted via a plot digitizer [124]. Combined sources[60] allow compiling a largely consistent 2000–2016 timeseries (Figure 40).

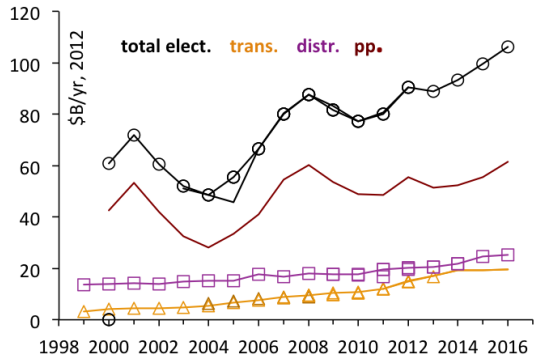

Figure 40: EEI investment for total electricity, transmission, distribution, and derived power generation (pp), inflation-adjusted to 2012 dollars. Open symbols show individual sources (see text) and solid lines final values chosen.

The *Bloomberg New Energy Finance (BNEF)* annual "State of Clean Energy Investment" reports track since 2004 a related measure, annual U.S. "clean investment" [475, 476]. The measure includes not only renewable electricity generation but unrelated "green" initiatives such as energy efficiency efforts and storage, but is still potentially useful for comparison.

[58] [138 Mining] includes "Oil and Gas Field Exploration Services" and "Oil and Gas Field Services" that are outside of the [213111 / 213112] NAICS categories

[59] This category includes natural gas transmission and distribution. The term "gas production" is not extraction but instead refers to "mixed, manufactured, or liquefied petroleum gas production and/or distribution," which is under NAICS [2212 Natural gas distribution] and included in our schema as natural gas distribution pipelines [462]

[60] EEI *transmission* investment values from 2006–2012 are taken from the 2013 FR release and for 2013–2016 from the 2017 release. Values for 1999–2005 are taken from a 2006 special EEI report [471]. We include for comparison in Figure 40 values from overlapping reports and other EEI sources [472, 473]. *Distribution* annual investment values for 2009–2016 are taken from individual FR reports. For 1999–2008, we estimate values from an EIA investment chart compiled from FERC filings [474]. For *total* investment, we use the 2010 FR release for 2000–2010 and 2016 for all other years.

L.4. Comparison of investment from different sources

Electric sector and transmission & distribution.

The BEA, ACES, and EEI all allow estimates for the privately owned part of the electricity sector. Both the BEA and EEI also provide a well-defined category for transmission and distribution. (ACES aggregates the entire sector.) Estimates from the three databases track each other well (Figure 41), though BEA values are ∼10% higher. All datasets show similar growth over time, and include two common perturbations: a burst of investment in the early 2000s associated with a rapid buildup of natural gas power plants after a time of depressed investment (see Section K), and a decline during the Great Recession of 2007–2009. Note that total values here omit government power plants (∼20% of generation assets) and T&D values omit municipals and co-ops (∼30% of distribution assets).

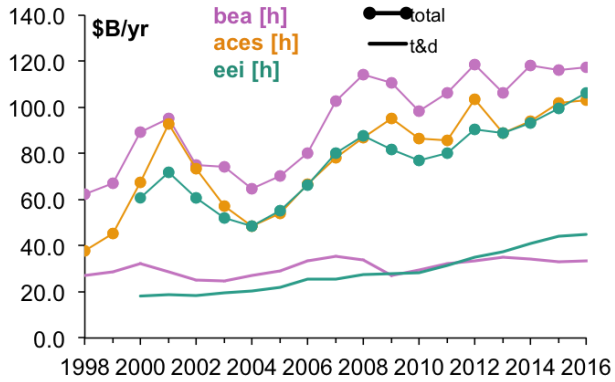

Figure 41: Comparison of total electricity sector and T&D investment for ACES, EEI and BEA (without government power), in historical costs inflation-adjusted to 2012 dollars. ACES and EEI do not include spending by municipal utilities or co-ops.

Renewables.

The BNEF "clean investment" estimates should exceed the BEA "wind and solar" category. While wind and solar will dominate spending on renewable electricity generation (Figure 32), the BNEF metric includes spending on non-generation items such as energy efficiency, and defines capital investment more broadly than in our inventory. The BNEF "clean investment" and BEA "wind and solar" measures do roughly track each other (Figure 42), but are too discrepant to provide useful insight.

In the BEA wind-and-solar total, year-to-year variations in spending appear driven by anticipated expiration of the U.S. federal Production Tax Credit (PTC) in 2010 and 2013. (The PTC has expired and been renewed multiple times since its enactment in 1992 [460].) The BNEF measure appears more strongly affected by the Great Recession, possibly because of its broader investment categories.

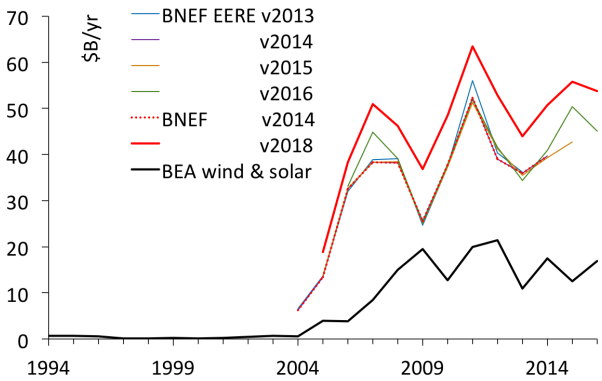

Figure 42: BEA wind and solar and BNEF "clean investment" from various releases, in nominal dollars. The two metrics track but as expected BNEF is substantially higher. We show values from two official BNEF releases in 2014 and 2018 [475, 476] and from secondary reports in the DOE annual Renewable Energy Data Book published by the Office of Energy Efficiency and Renewable Energy (EERE) [477–480]. The 2018 BNEF release raises historical values by 10-30% over previous versions.

Power plants.

The BEA and EEI datasets allow constructing an estimate for electricity generation facilities (power plants) alone, and restricting analysis to power plants also allows comparison to our physical inventory. This comparison for 1950–2016 comparison is shown in Figure 43. Black line is our inferred "value-added age structure", the timeseries of past investment in power plants still operational in 2012. (We sum all categories in Figure 32, including wind and solar). These values should be lower than actual annual investments, which include spending on plants since retired, as well as upgrades and refits. Sources are in reasonable agreement, though the inventory-derived estimate is substantially larger during the 1970s–1980s, when most currently operational coal and nuclear power plants came online.

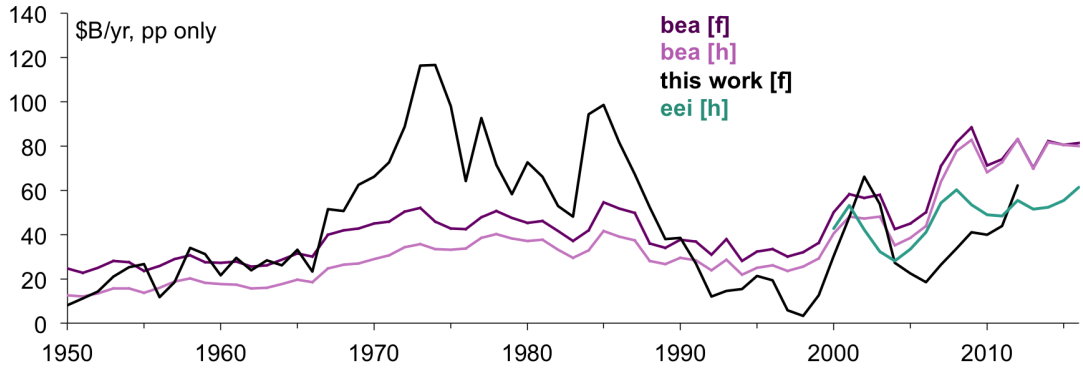

Figure 43: Comparison of estimated investment in U.S. electricity generation (power plants or "pp") from the EEI (green) and BEA (purple) datasets and inferred from this work (black). To match inventory values, BEA values here include wind and solar and government power, though not the ambiguous category of "other utilities". The EEI omits government (municipal) power plants, so should be 15-20% lower than the BEA total. Inferred investment from this work should also be lower as it includes only power plants still operational in 2012. [h] denotes values in historical costs, inflation-adjusted to 2012 dollars; [f] denotes values in 2012 fixed costs, with both inflation and price adjustments.

The discrepancy in the 1970s–1980s likely results from a rise over time in plant-specific construction costs that is not reflected in the BEA price adjustment. The BEA price index, which is based on the general Handy-Whitman index for public utilities [440], increases only by 30% from 1970–2012: compare BEA [h] and [f] curves in Figure 43. Actual construction costs of coal plants more than tripled over this period, from <$1000/kW in 1970 [481] to our 2012 EIA-based estimate of $3,246/kW [9]). Costs of nuclear plants increased even more steeply [482]. The BEA adjustment therefore undervalues the fixed-cost investment in power plants in the 1970s-1980s.

In some cases, the inventory-derived timeseries appears to lag against estimates based on annual spending. A lag is expected since the inventory assigns all investment to the first operational year for each power plant rather than spreading it over several years of construction. Low values after the 2008 Great Recession may also imply that reduced demand led to delays in power plant completion.

Pipelines.

Datasets show broad agreement on historical pipeline investment (Figure 44). We compare BEA and ACES investment and the value-added age structure from our work (whose values are only in decadal increments since it is based on a 10-year-resolution age structure from the PHMSA [4–6]), for total pipelines and for oil and gas pipelines separately. (The BEA does not disaggregate pipelines by fuel.) Before about 2006, the inventory-based timeseries is broadly consistent with BEA fixed-cost investment estimates, suggesting that few pipelines have been retired. Separate estimates of oil and gas pipeline investment are also in reasonable agreement with our inventory. After 2006, the inventory does not reflect the boom in pipeline investment associated with the fracking revolution that expanded domestic oil and gas sources. The discrepancy occurs in part because a physical inventory cannot track rapid transitions – the long duration of pipeline construction means that online year lags behind investment measures – but also because the BEA pipeline price adjustments apparently do not account for a price increase associated with the fracking boom.

Oil and gas extraction.

For oil and gas extraction, we compare four sources: BEA and ACES investment, an estimate based on EIA well cost and annual new well count [70, 483], and a value-added age structure constructed from our physical inventory. Figure 45 shows the resulting comparison between all estimates, with BEA values given as both fixed and historical costs. All datasets show the temporary booms in domestic investment associated with the oil price spike of the 1970s–1980s and the fracking revolution of the 2000s. While sources in historical costs broadly agree, BEA fixed cost estimates appear excessively high, inflated by a too-large price adjustment, as discussed in section L.5. (See Figure 39.)

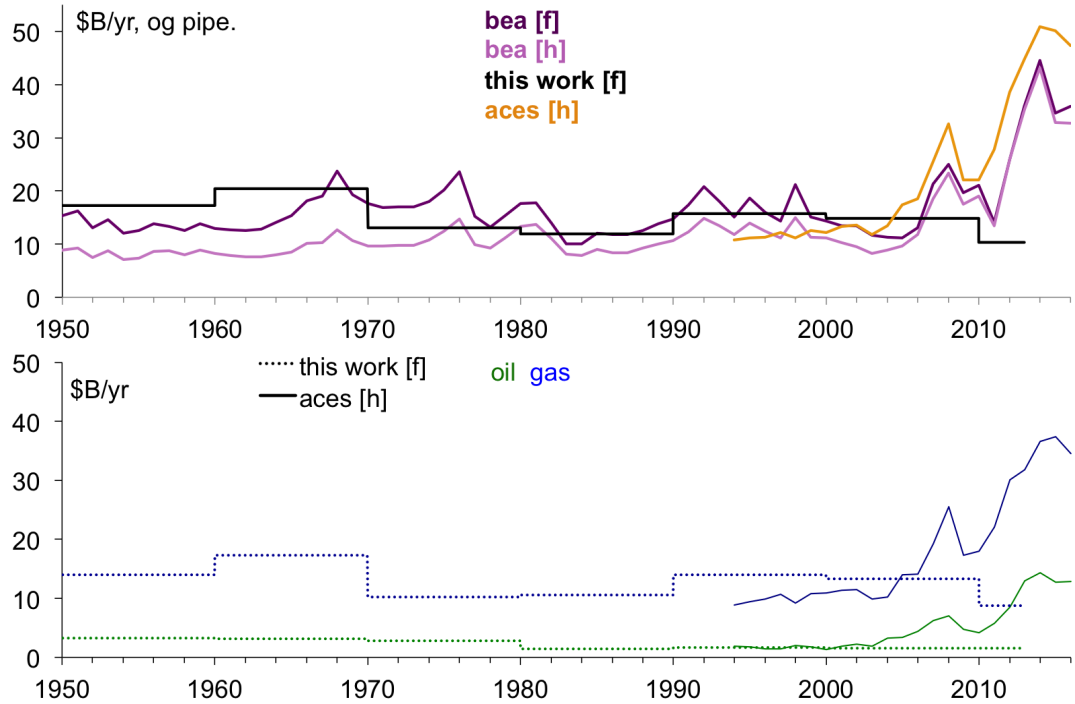

Figure 44: Comparison of oil and gas pipeline investment data for ACES, BEA, and this work. [h] denotes historical costs inflation-adjusted to 2012 dollars, and [f] fixed cost in 2012 dollars and prices. Pipelines in our inventory are derived from the PHMSA dataset, which lists online year only by decade. PHMSA icludes pipelines completed in 2010-2012, but cannot capture pipeline projects begun but not completed in that timeframe. Investment estimates are generally in agreement, though problems with the BEA price adjustments may affect the comparison before 1970 (when investment appears low relative to our inventory) and certainly do in 2006-2012 (when investment appears high). The post-2006 investment spike is associated with a construction boom for new oil pipelines, but with no change in gas pipelines (Figure 35). Instead, gas pipeline prices rose sharply (Figure 17), but the BEA price index does not reflect this rise (Figure 39). The result is a likely spurious trend in BEA fixed-cost investment. Note that in this work we also ignore the pipeline price rise by choosing costs appropriate for pre-2006 conditions.

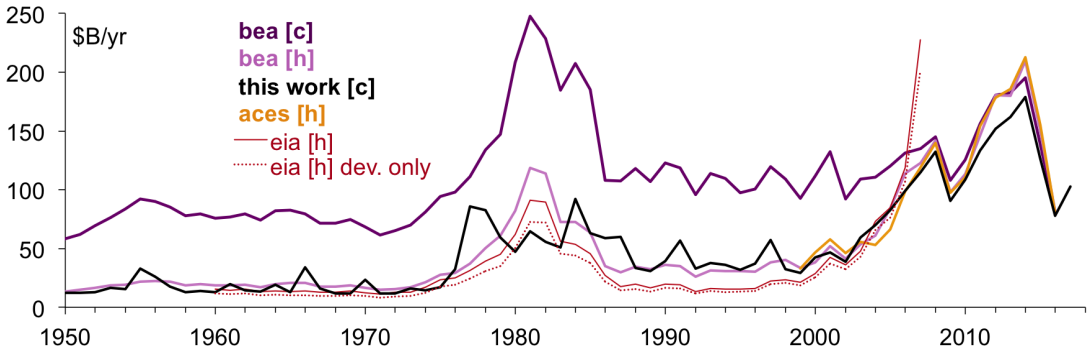

Figure 45: Comparison of oil and gas extraction investment data for ACES, BEA and inferred investment from this work and EIA. [h] denotes historical cost, inflation-adjusted to 2012 dollars, and [f] fixed cost in 2012 dollars and prices. Values are broadly in agreement, with some exceptions. The EIA-based estimate extends only from 1960–2007because it uses API JAS-based costs for this period [110]), and the 2007 value is likely a data error. JAS per well costs show a reasonable rising trend from $650,000 in the 1980s to $1.2M in the the early 2000s, but a likely erroneous value of $5 M in 2007. (See Section B.4.) In the benchmark year of 2012, the inventory-based investment estimate is ∼15% lower than the BEA value, likely because we use conservative (low) cost estimates to avoid the temporary spike in well costs in 2012. We also do not include exploration spending, which may make up 7-30% of total well cost [3, 50]. BEA fixed-cost estimates in earlier years, before the fracking revolution, appear inflated by a too-large price adjustment.

L.5. Timeseries of energy-related net stock

The mapping of the complete energy sector to BEA categories in Table 35 allows constructing a (depreciated) value of U.S. energy infrastructure not just for our baseline year of 2012, but for all years for which the BEA has data. We use a 2018 BEA release that conveniently provides "fixed cost" values adjusted to 2012 dollars and prices, allowing us to generate a self-consistent timeseries of the evolution of the value of domestic energy-sector assets from 1949 to 2016 (Figure 46). (See below for details on methodology.) The value of U.S. energy assets rises nearly six-fold over this 68-year period, driven largely by increasing total energy use. Dividing by energy use lets us calculate the growth in the *capital intensiveness* of the U.S. energy sector. Since the BEA FAA does not include assets associated with foreign oil and gas imports, the most relevant scaling is by import-adjusted energy production (Figure 46, red). Capital intensiveness more than doubles over the timescale shown, with the most rapid increase in the 1970s and early 1980s, before stabilizing in recent years (at \$1.63/W in 2012, and \$1.64/W in 2016). The BEA-derived capital intensiveness is about half as much as the *undepreciated* estimate of \$3.3/W derived by dividing the inventory total, \$9.8 T, by U.S. total primary energy flow, 3.0 TW. That is, U.S. energy sector assets appear to retain about half their upfront value under the BEA depreciation scheme.

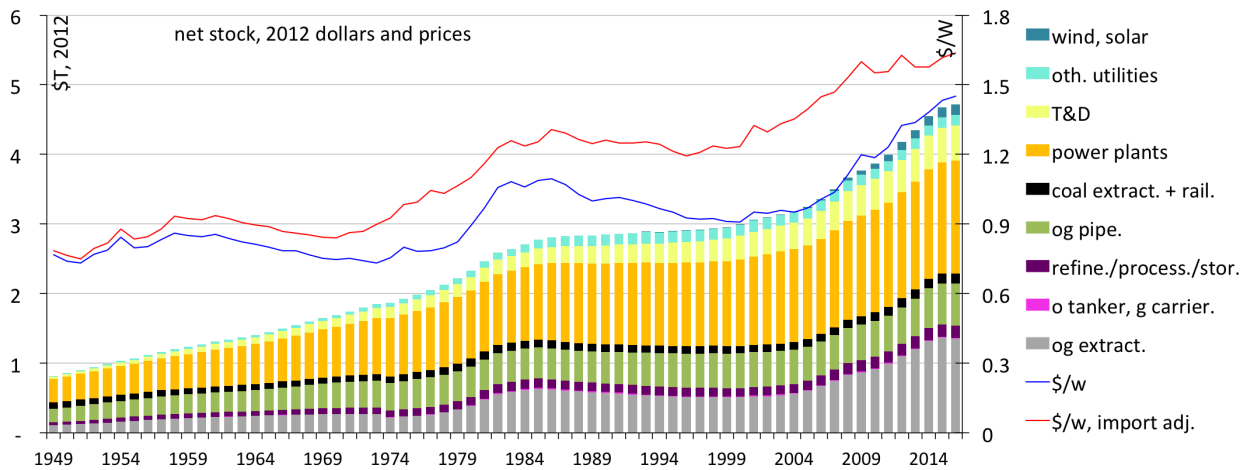

Figure 46: Total domestic U.S. energy sector depreciated asset value over time, from v2018 BEA FAA data [434, 435], price- and inflation- adjusted to 2012 dollars and prices, and the selection scheme of Table 35. Oil and gas extraction are derived separately from raw historical investment timeseries to exclude the BEA price adjustment. (See discussion below.) For simplicity we combine some categories, grouping *Other Oil and Gas* with *Oil and Gas Extraction* and *Coal Extraction* with *Coal Railroads*. Red and blue lines show energy sector capital intensiveness in \$/W, which doubles over this time period. Blue line is asset value here divided by total U.S. primary energy usage [EIA 329, Table 2.1]; this value is an underestimate since assets here omit those associated with foreign oil and gas. Red line is asset value divided by import-adjusted energy flow (total primary energy usage minus net import of foreign oil and gas][EIA 329, Tables 3.1 and 4.1]; this value should be a slight overestimate since some assets here are used in processing imported oil and gas.

Trends in the depreciated energy infrastructure asset values of Figure 46 reflect major events in U.S. energy history. The electric sector shows steady growth until the 1990s, followed by a decade of very little investment in new generating plants, as discussed in Section K. Domestic oil and gas extraction infrastructure shows two periods of rapid growth: the late 1970s, when high oil prices spurred the development of expensive domestic sources [361], and the post-2003 era when rapid development of domestic fracked sources displace foreign imports. These periods of development are reflected in the age distribution of currently producing U.S. wells (Figure 33). Capital intensiveness rises from the 1973 OPEC cris til the mid-1980s because high energy prices led to relatively flat energy consumption even as energy infrastructure continued to grow, and declines in the mid-1980s and 1990s because of the opposite conditions, rising energy consumption during a period of low investment in power plants and wells. Import-adjusted and non-adjusted capital intensiveness (red and blue lines in Figure 46) diverge in the late 1970s because of increased dependence on imported oil, and converge again in the mid-2000s as the fracking revolution shifts production back to the U.S.

Some other features of these estimates appear more problematic. First, electricity generation makes up a nearly constant share of U.S. energy infrastructure value, even though electricity plays an increasingly prominent role in the U.S. energy sector over time. Between 1949 and 2016, the fraction of U.S. primary energy devoted to electricity production rises nearly fourfold from ∼10% to nearly 40% [484], but electricity's share of asset value in Figure 46 varies only between 47–59%.[61] The complete removal of the price index for oil and gas extraction may leave early oil and gas assets somewhat undervalued, but another explanation may be that non-electricity energy use in the past was simply less dependent on long-lived assets. The U.S. pipeline network, for example, is negligible in the 1940s and is built out only gradually over the following decades [484]. Electricity may therefore have accounted for a disproportionate share of assets in the early U.S. energy sector.

Second, electricity transmission and distribution (T&D) net stock values derived from the BEA are very small relative to our inventory replacement value. In 2012, the BEA T&D net stock of \$463 B[62] is only ∼20% of our upfront asset value for electrical lines plus substations (\$2.20 T). The low net stock estimate results in part from the BEA's assumption of a depreciation timescale much shorter than the actual service life of grid components (Section M), but depreciation cannot be the only explanation, because the sum total of all BEA investment in electricity T&D since 1949 is actually below our inventory value: only \$1.12 T with price adjustments or \$1.26 T without. Part of the discrepancy may be mis-labeling of assets, as discussed in Section L.2. If we assume the entire "other utilities" category are T&D lines[63], the sum total investment becomes \$1.87 T with price adjustment and \$2.09 T without, and adding the transmission lines and municipal distribution included in "government power" would likely add a few hundred billion more. Using a price index consistent with those for other asset categories would raise the BEA T&D value further. Plausible adjustments could therefore raise the cumulative BEA T&D investment to slightly above our estimated 2012 replacement cost, but this scenario would still imply that few power lines have been retired.

Note that the total 2012 net stock shown here (\$4.18 T for 2012 in Figure 46) is lower than that shown in Section J where we originally discussed the BEA methodology (\$4.47 T in Table 35). The difference of −0.3 T results in part from the use of different BEA releases, v2018 in Figure 46 and v2013 in Table 35 (which produces an increase of +0.2 T), and in part from removing the BEA price adjustment for oil and gas extraction (which produces a decrease of −0.5 T).

Net stock timeseries methodology.

We use the v2018 BEA release for the net stock timeseries because it provides a version of the Detailed Fixed Asset Tables for privately owned assets with "fixed-cost" values for all years. That is, v2018 provides values adjusted with both price and inflation adjustments to 2012 dollars and prices. Values over time are then fully consistent and trends are readily interpretable. However, constructing the net stock timeseries of Figure 46 still requires two additional steps: removing the price adjustments for oil and gas, and accounting for government-owned electrical assets. We discuss these below.

Government power. The BEA does not provide fixed-cost asset tables for non-private assets, so the "government power" category is reported only in current cost, i.e. in costs adjusted to each individual year's inflation and price level. Government power is a substantial part of the total inventory, making up 3.6% of total 2012 energy sector value in Table 35, and, if assigned to power plants, 21% of total 2012 asset value in power plants other than than wind and solar. To make government-owned asset values comparable, we apply a rough composite index that accounts for both inflation and price changes, constructed by comparing the BEA private power-plant net stock values in fixed and current costs [434, 435]. This adjustment effectively assumes that investment in private and government power plants is identically distributed over time. Resulting values appear broadly reasonable, since after adjustment, government power makes up a relatively constant share of U.S. power plant assets at 15–22% over the entire timeseries.

[61] The fractional share of electricity-related assets in the total BEA energy-sector depreciated value peaks at 59% in 2004 and then falls to 50% in 2016, after the development of fracking drives a boom in domestic oil and gas investment.

[62] T&D net stock in 2012 is only slightly different between BEA FAA releases, at \$459 B in v2013 and \$463 B in v2018.

[63] The "other utilities" category is however ambiguous and likely also contains non-electricity related asset items, and possibly some related to generation.

Oil and gas investment price adjustment. While for most asset categories we want to use the BEA price adjustment, the adjustment for oil and gas extraction appears to over-value early investments. (See Figure 39 in Section L.2.) We therefore re-derive a net stock timeseries for oil and gas extraction that does not use the BEA price index. To do this, we work directly from the BEA investment timeseries using the BEA methodology [425]: for each year in the timeseries, we apply an inflation adjustment to investments in all prior years, iteratively depreciate them, and sum them up. For inflation adjustments in the year 1929 and after, we use the GDP deflator published by the U.S. Census Bureau [485], the standard inflation adjustment measure used throughout the inventory. For years prior to 1929, where this GDP deflator is not available, we use the consumer price index from the Bureau of Labor Statistics [486], which functions as an alternative inflation measure [487].

To verify that we are correctly reproducing BEA methods, we conduct two partial validation exercises in which we confirm that our procedure reproduces BEA fixed cost net stock timeseries for selected categories. For this purpose we choose simple and well-understood categories whose assets are subject to only a single depreciation timescale: office buildings and petroleum pipelines. We use 2012 fixed cost investment to derive 2012 net stock vales and compare our results to BEA published values (Figure 47). The close alignment between our computed value and that reported by the BEA implies that our metholodology is sound.

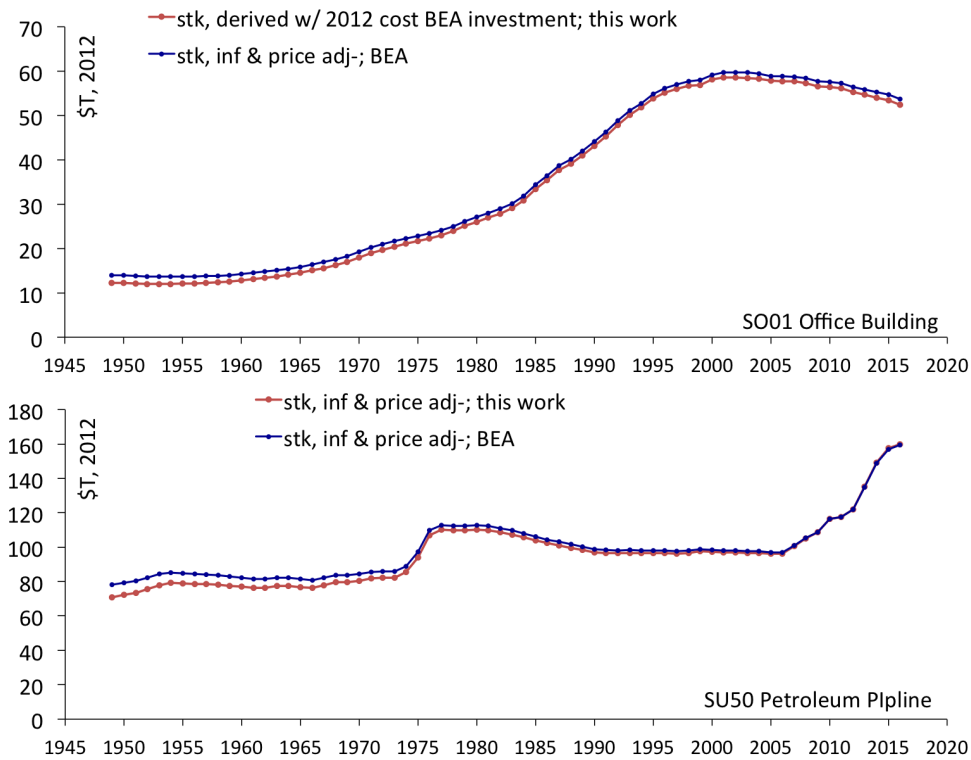

Figure 47: Validation test of our net stock derivation calculation, for BEA categories SO01 (Office buildings) and SU50 (Petroleum pipelines), attempting to reproduce the BEA methodology of [425]. We use 2012 fixed cost investment data and calculate each individual year's net stock as the sum of depreciated past investments, with geometric depreciation as described in [485]. The resulting net stock estimates show close agreement to BEA published values in 2012 fixed costs. Residual small offsets may be due to undocumented "external factor" adjustments that are made by the BEA in their net stock calculation, intended to account for financial circumstances or historical events such as natural disasters that affect asset valuation.

M. Service life of energy assets

The primary motivation for this inventory is to understand the limitations on the speed of transition in the U.S. energy sector caused by existing infrastructure. This capital-driven inertia is directly tied to how long existing assets in the energy sector last. Service life information is also needed for several derived statistics we report, including the normalized capital cost per unit of energy that is described in Section N. In this section we assess the service lives for all asset categories listed in our inventory, which range from 20 years for oil and gas wells to 60 years for nuclear and hydro plants. (We do not consider assets with service life < 20 years.) Choices for all categories are describe in detail below, and Table 37 below summarizes age information for selected major categories.

	BEA	**"Turnover time"**	**Service life**	**Mean age ×2**	**Mean year**
Oil & gas wells	12–16	10	20	27	1998
Conv. vertical			20	39	1992
Horizontal			20	10	2007
Offshore deep			20	20	2002
Offshore shall.			20	39	1992
Power plants	45	45		63	1980
Gas			30	40	1992
Oil			30	72	1976
Coal			50	73	1976
Nuclear			60	62	1981
Hydro			60	93	1966
Wind, solar	30	7	25	8	2008
Pipelines	40	29	60	64	1980
Oil		20	60	81	1971
Gas *(trans. & gath.)*		35	60	80	1972
Gas *(distr & serv.)*		28	60	60	1982
Elec. trans. & dist.	33	70	50		

Table 37: Age measures for selected major categories in our physical inventory: the BEA estimate of financial lifetime, our assumed physical lifespan, and two metrics derived from our physical inventory where possible. The "turnover time" is the total upfront asset value divided by the 2012 investment; the "Mean age × 2" is twice the mean age (calculated using weighting by asset value). (Note that while most asset ages are specified annually, pipeline mileage is specified by decade.) If asset populations are in steady-state, these metrics will equal the physical lifespan. Differences in age metrics can reflect a non-flat age structure. In a growing asset category (more investment at present than in past), apparent turnover time will be short relative to physical lifespan; in a stagnating category (more investment in past), turnover time will be long.

Table 37 also compares our estimated service lives with the BEA financial lifetimes and with two age-related metrics derived from this inventory: the apparent turnover time of the category (asset value divided by 2012 investment), and the value-weighted mean age of inventoried assets (×2 to match the service life). These latter metrics will match the service life if the asset category is in steady-state. The comparison largely supports our choices for service lives. Discrepancies are consistent with several scenarios already discussed in Sections K-L. Both oil & gas wells and pipelines are long-standing and large sectors experiencing a recent boom in investment, producing apparent short turnover times even while mean ages of existing assets remain high. Wind & solar power plants and horizontal (fracked) wells are technologies so new that assets are very young, with mean ages of assets (×2) below expected service lives. Many other generation technologies (hydropower, oil- and coal-fired generation, and nuclear) are "stagnant" categories whose periods of growth are in the past, marked by disproportionately old assets or small levels of current investment.[64]

[64]The long apparent turnover time of electricity T&D may be in part an artifact of the underestimation of T&D investment discussed in Section L.5. If for example the $12 B in 2012 investment in "Other utilities" is added to the $33 B in T&D, apparent turnover time drops to 50 years and matches estimated service life.

The service life we define for each asset category is the expected physical lifespan, a metric different from the economic or financial lifetime used for taxation or accounting purposes. The "financial life" of an asset (a term used in the Internal Revenue Service's Modified Accelerated Cost Recovery System) can be considerably shorter than the expected duration before that asset is retired [e.g., IRS 488–492]. Depreciating energy sector asset groups using their BEA FAA financial lifetimes (see Section K) leaves assets with ∼40% of their original upfront value even at the end of their defined lifetime. Table 37 also shows that for many energy sector asset classes, a substantial portion of infrastructure remains in use beyond its BEA lifetime. Determining how long a physical asset remains in usage therefore requires alternative sources than the BEA.

We consider a variety of sources for this purpose. Where available, we use physical life estimates from company reports. Age structures in this inventory, if available, also inform our choice of service life choice. In the case of steady investment and uniform lifespan, the physical lifespan would be twice the mean age of inventoried assets. When there are few alternative sources, we are guided by the financial lifespan used in depreciation guidelines for tax purposes (by either the federal Internal Revenue Service or state and local governments) or in private company SEC filings and annual reports, but consider these measures as a lower bound on physical lifespan. The remainder of this section discusses in detail the estimates for each asset category.

Oil and gas wells – 20 years. The service life of wells is the most complicated and least well-defined of any asset category in our inventory. Complicating factors include that: 1) the operating life of individual wells is variable, with some wells taken out of service within a year and others operating for decades; 2) production is highly variable across wells, and those with lower production rates are retired earlier; 3) production in an individual well declines over time; 4) well technology evolves over time, even within each class, so that production curves differ for wells drilled in different years; and finally, 5) the well fleet is not stationary in age structure (e.g. modern fracked wells are quite recent). This combination means that defining relevant service lives is difficult. We address the problem in three ways, described below. First, we calculate the 'survival curves' of wells of each type, i.e. the probability that a well will remain in service as a function of age. Second, we roughly estimate production decline rates to evaluate whether this factor should substantially affect our service life estimates for fracked wells. Finally, we consider whether the design life of oil and gas drilling and pumping equipment is comparable to that of the wells themselves.

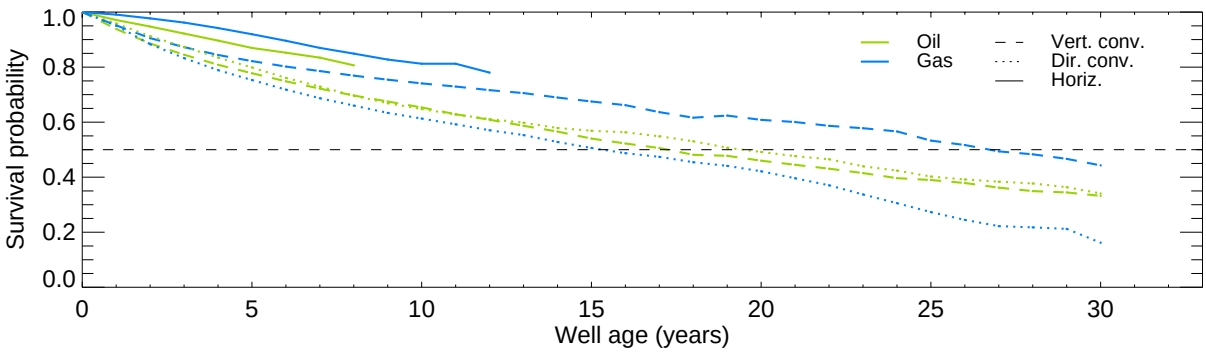

Figure 48: Fraction of wells that remain active as a function of time since first production, from DrillingInfo 2018 [1]. We show selected categories and use only wells with first production date on or after a threshold year: 1985 for all conventional wells; 2003 for horizontal (fracked) gas; 2007 for horizontal oil. Earlier horizontal wells do not represent modern fracking, and earlier conventional wells are more inconsistently recorded. Because production records are also inconsistently recorded in years close to the database release, we use only wells with listed last production date of 2015 or earlier; this choice has only minor effects. Survival curves for conventional wells imply operating lifetimes around 20 years. Survival curves for horizontal fracked wells are shallower, implying longer operating life, though modern fracking is so recent that few wells have been retired.

We calculate survival curves for onshore wells from our primary source for well information, the DrillingInfo 2018 database [1], which records first and last production dates, and take the mean operating life as the age when 50% of wells have ceased production. For conventional wells of all types, this threshold is reached

after about 20 years (Figure 48). For modern fracked wells, survival rates are higher, so extrapolating would suggest a mean operating lifetime longer than 20 years. The history of modern fracking is however so short that no cohort of fracked wells has reached 50% retirement. Over 90% of all modern fracked wells drilled in the U.S. remain in service in 2018, and over 75% even of the earliest cohort from 2003.

Fracked wells, which make up about half of asset value in the U.S. well fleet in 2012, are generally acknowledged to have more time-variable production rates than do conventional wells. We therefore evaluate whether this behavior should affect the estimation of service life. While Drillinginfo data does not allow following individual wells over time, it allows rough determination of decline rates for the aggregate fleet by examining the growth in cumulative production with well age. Any decline curve estimate requires some normalization, because evolution in fracking technologies means that more recent horizontal wells produce more strongly. We use two Drillinginfo data fields – cumulative production and "first 12 month" production[65] – to track the rate of growth of well output relative to first-year production for wells of different ages (Figure 49). In the aggregate fleet, wells of all types take roughly 3–5 years to double their first-year production and 10–15 years to quadruple it. Fracked wells do exhibit steeper declines than conventional wells (slower growth in cumulative production), but the difference is suprisingly modest, and is minimally affected by retirement of the lowest-producing wells. (Results are similar even if analysis is restricted to only wells still active in 2018.) We therefore do not treat horizontal wells differently from conventional wells in this inventory, but conservatively take their lifetime as 20 years.

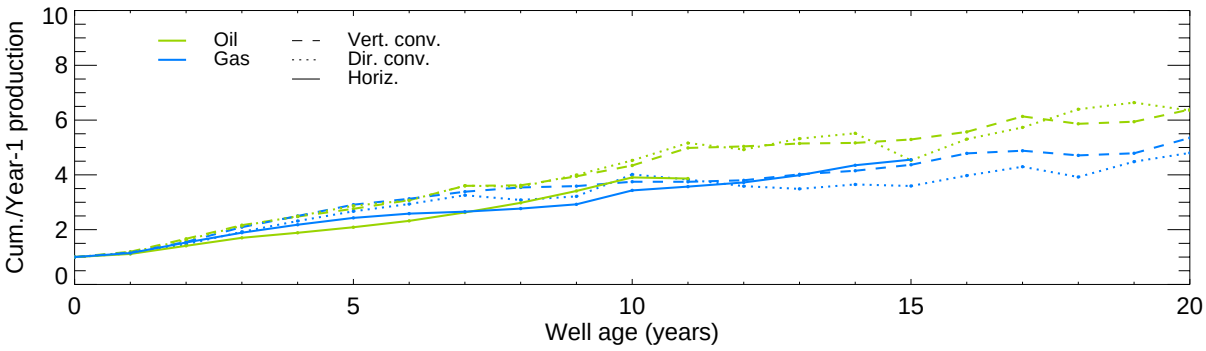

Figure 49: Growth in well production with age, normalized to production in the first year, from the 2018 Drillinginfo release. Values are computed by combining all wells of a given age and taking the ratio of their aggregated 'first12' and 'cumulative' production. Data here include both wells active in 2018, whose current age is set by their date of first production, and inactive wells whose final age is set at retirement, but results are robust to the well selection choice. (Results are similar in analyses that include only 2018-active wells, or only wells retired before 2016 as in Figure 48.) Well production declines after the first year for all well types, somewhat more strongly in horizontal (solid) than in conventional (dashed) wells. That is, normalized cumulative production rises more slowly for horizontal wells, but differences are not large.

It could be argued that any infrastructure whose capacity declines over time should be assigned an effective service lifetime lower than its mean operating lifetime, because of its declining value. Under that rationale, all oil and gas wells might fall below the 20-year threshold required for inclusion in this inventory. However, oil and gas companies concur in assuming well lives in excess of 20 years in internal analysis. Security Exchange Commission filings from TransOcean, Kinder Morgan, and Exxon from 2014-2018 report average well life of around 25 years, based on the cost of property and equipment and depreciation and depletion expense [493–495]. Several smaller oil and gas firms (Encana and PA Resources) state a 20-30 years lifespan on their official websites [496, 497]. These estimates are considerably longer than the service life assigned by the *BEA FAA* [441] which uses 16/12 years lifespan for wells completed before/after 1973, under the description of *Private nonresidential structures: Mining exploration, shafts, and wells – Petroleum and natural gas.*

[65]The use of selected Drilllinginfo data fields (cumulative and first 12 month production) does not bias results since for all well categories shown, 85–93% of the relevant well entries in the Drillinginfo database contain this information.

It is also an important consideration that the equipment used in oil and gas extraction is itself long-lived. For convenience, we have estimated the value of oil and gas infrastructure by considering the cost of drilling wells rather than by itemizing the hardware involved – drilling rigs, pumpjacks, and offshore platforms – but their operating life is also a relevant factor. Service life is most extensively documented for offshore equipment and is commonly cited as 25 years. The Bureau of Ocean Energy Management (BOEM) states in a 2013 report that "Rigs are designed to have operational lives of around 25 years, but rigs often work for 30 years or more and the oldest operating rig in the current fleet is 54 years old" [498]. A 1996 report by the National Academy of Sciences on aging offshore infrastructure states that "Approximately one-fourth of the platforms in the OCS region of the Gulf of Mexico are more than 25 years old and have reached or exceeded their design life" [499]. Newer equipment should be even more durable: a Northern Offshore Ltd. directors' report from 2008 states that offshore rigs are now designed for 30 years of usage [500]. Onshore equipment is less well documented, but Schlumberger advertises pumpjacks with design life of "over 25 years" [501] and American Engineering Testing reports design life of 30 years for pumpjacks in the Bakken [502]. We consider 20 years to be a reasonable choice for an aggregate service life for oil and gas extraction infrastructure.

Oil pipelines – 60 years. The steel pipelines that carry oil and natural gas are extremely long-lived assets. The Interstate Natural Gas Association of America notes that "[t]he properties of the steels that comprise ... pipelines (including the oldest steel pipelines in service) do not change appreciably over time; that is, the pipe steel does not 'wear out"' [503]. Physical lifespans for pipelines are therefore somewhat difficult to specify. The Trans-Alaska oil pipeline, built in 1977, is assumed by the State of Alaska's tax division to be operational until 2042, i.e. 65 years [504, 505]. The U.S. oil pipeline system is overall very old, with few retirements to guide an assumption of design life: value-weighted age of U.S. oil pipelines is over 40 years and a substantial portion of the system is over 70 years old, i.e. dating from before 1940. The age structure of pipelines operational in 2012 is nearly flat (Figure 35), though fracking has led to a recent burst of investment (Figure 44). Newer pipelines should have even longer lifetimes given improvements in steels, coatings, techniques of welding and bending, and tools for pipeline inspection [503]. We choose a conservative 60 years. Note that the *BEA FAA* appears to have substantially underestimated oil pipeline lifetime, assigning a value of 40 years under *Private nonresidential structures: Petroleum pipelines*.

Natural gas pipelines – 60 years. Natural gas and oil transmission pipelines share similar technologies and should have similar lifespans. As with oil, defining a design life for gas pipelines is not simple; INGAA states that "a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely because the time-dependent degradation threats can be neutralized with timely integrity assessments followed by appropriate repair responses" [503]. A report on gas transmission pipelines prepared for the Pipeline Safety Trust similarly states that "a properly managed steel pipeline has a life expectancy of well over a hundred years, if not significantly longer" [506]. The compressors associated with natural gas transmission are also designed for lifetimes of 50 years or more [507]. The age structure of U.S. natural gas transmission and gathering pipelines is similar to that of oil pipelines, with a value-weighted mean age of 40 years and some pipelines operational beyond 70 years. The smaller distribution and service pipelines that dominate the total upfront cost of the U.S. natural gas pipeline system have younger mean age (35 years), but the difference may relate to the history of expansion of residential gas service.

We assume for the purpose of a lifespan estimate that all gas pipelines have similar life expectancy, and assign 60 years. Note that we base our lifetime estimate on modern technologies: steel or, in the case of distribution and service pipelines, plastics or composites. Some earlier technologies, such as the cast iron used in the 1920s–30s, have particular weaknesses that lead to age-related failures. Canary, LLC estimates that 3% of gas distribution mains in service in 2014 are brittle cast or wrought iron [508], and a report prepared for the American Gas Foundation estimates that 112,000 miles or 9% of all U.S. distribution mains in service in 2011 are constructed from older, leak-prone materials [509]. Economic lifetimes of natural gas pipelines, like those of oil pipelines, appear underestimated in the *BEA FAA*. Natural gas pipelines likely appear in (and dominate) the category of *Private nonresidential structures: Gas* and are assigned 40 years.

Refineries – 60 years. While we do not have a formal age structure for the U.S. refinery fleet, refineries are widely known to be very old. The majority of existing U.S. capacity was built in the 1950s–1970s, suggesting service lives of at least 50–70 years. The last greenfield construction in the U.S. with significant downstream capacity as of 2019 dates back 42 years to 1977 (Garyville, Louisiana with 564,000 bpd capacity, from the archived annual *EIA Refinery Capacity Report* series on refinery capacity, which includes the most recent refinery constructed [216, 510–512]). The 2013 EIA report in this series [510] suggests that 94% of all U.S. capacity is built on or before 1975 (37 years old at the time of publication) and 92% on or before 1967 (45 years old). The oilfield services company Canary, LLC estimates that "most US refineries are between 50 and 120 years old" [221].

Another source of information on service life is the age of refineries at retirement. The annual *EIA Refinery Capacity Report* series provides the length of operation for all retiring plants shut down between 2006 to 2009. We eliminate from this list several retiring plants that appear either new or in operation only a few years, implying that their shutdown is driven by economic reasons rather than by an age constraint. The five older retiring plants had operating lifetimes of 29–61 years, with a mean of 48 years.[66]. This number is likely biased lower than the eventual mean retirement age of the entire U.S. fleet, since the system is not in steady state. Many of the earliest refineries built in the U.S. remain in operation, e.g. B.P. Whiting in Indiana, whose construction begain 130 years ago in 1889. However, the age of first operation of the nation's oldest refineries does not provide a simple measure of service life, since older U.S. refineries have experienced significant capital upgrades and capacity expansions through their lifetimes. (For this reason, U.S. refining capacity has continued to expand even as the number of refineries contracts.) Given these complications, we take 60 years as a reasonable estimate.

Natural gas processing plants – 35 years. Little information exists on the physical lifespan of natural gas processing plants. The *BEA FAA* depreciation scheme provides little guidance, since gas processing plants fall under the broad category of *Private nonresidential structures: Gas* (40 years), which should be dominated by natural gas pipelines. We therefore turn to taxation guides to develop a lifetime estimate, specifically to the IRS tax depreciation system termed the Modified Accelerated Cost Recovery System (MACRS). The MACRS asset life table (reported by *Thomson Reuters* [517]) gives financial lifetimes of 30 years for a *Gas Utility Mfgd. Gas Production Plant* and 14 years for a *Natural Gas Production Plant*. These numbers are likely underestimates for our purposes, since taxation schemes tends to underestimate asset lives, so we assume a slightly larger 35 years.

Oil rail cars – 35 years. Tank cars that carry oil by rail became highly important in the U.S. energy system in the mid-2000s at the beginning of the fracking boom, when the rise in oil production from shale plays with limited pipeline connectivity meant that large volumes of oil were carried by rail. The resulting concern over the safety of oil tank cars (accelerated by the death of 47 people in the 2013 Lac-Mégantic rail disaster) led to extensive documentation of their characteristics during formulation of new safety standards. At a forum sponsored by the NTSB (National Transportation Safety Board) in 2016, expert testimony described the older rail cars to be phased out as having an expected service life of 50 years [518]. (Similarly, a European study gave service life of 45–50 years to tank cars carrying mineral oil products and LPG [519].) Newer tank cars appear to have somewhat shorter service lives. A 2008 Notice of Proposed Rulemaking by the Pipelines and Hazardous Materials Safety Administration (PHMSA) assumed that the useful life of

[66] The *EIA Refinery Capacity Report* series allows lifespan determination for retirements during 2006–2009 since it gives both initial and final dates for each facility ("Date Operable" and "Date Shutdown"), but after 2010, "Date Operable" is no longer provided. The shut-down plants and their lifespans are described in Table 13, "New, Reactivated, and Shutdown Refineries". The five long-lived plants retiring are:

- Dow Haltermann Products in Channelview, TX, 01/48 – 12/05, 48 years [513].
- Hunt Southland Refining Co in Lumberton, MS, 03/66 – 12/06, 40 years [514].
- Gulf Atlantic Operations LLC in Mobile, AL, 03/78 – 09/07, 29 years [515].
- Sunoco Inc in Westville, NJ, 01/50 – 02/10, 60 years [516].
- Valero Energy Corp in Delaware City, DE, 01/48 – 1/09, 61 years [516].

new double-jacketed cars would reach at least 40 years for the outer tank, with potential re-use of the inner tank [520]. (Note thata the underframes of tank cars must by regulation be retired after 50(40) years for cars built after(before) 1974 [521]). During the final stages of rulemaking, numerous sources described a 35 year service life for oil tank cars: a 2014 report prepared by ICF International for the American Petroleum Institute [522], a 2014 presentation of the Association of American Railroads to the National Transportation Safety Board (which gave an economic life of 30-40 years) [523], and related media articles [271]. After new standards were finalized in 2015, an analysis on their effects presented to the White House Office of Management and Budget also assumed a 35 year service life [524]. We take this widely-used metric as the service life of U.S. tank cars.

Oil tankers – 30 years. The service life of large cargo ships is typically quite long, but oil tankers in particular are have specific limitations on service life set by the International Convention for the Prevention of Pollution from Ships's Maritime Pollution annex (MARPOL): MARPOL requires that all tankers be "converted or taken out of service" at 30 years age [525]. (In some cases, tankers reaching 25 years are also required to retrofit for prevention of oil spills or other accidents.) The mean ages of decommissioned oil tankers do appear somewhat shorter – 21 years according to the Baltic and International Maritime Council in 2013 [526] – but this may be biased low since older tankers had shorter lifespans. We assume that all modern tankers achieve the 30 year cutoff specified by MARPOL. This service life exceeds the financial lifespan of 27 years assumed by the *BEA FAA* for the broad category of *Private nonresidential equipment: ships and boats*.

LNG carriers – 30 years. The Oil and Gas Journal, a leading trade publication, describes the typical design life for recent LNG carriers in a 2007 article as 40 years [527], longer than the 27-year financial lifetime of the *BEA FAA* broad category of *Private nonresidential equipment: ships and boats*. We take a more conservative 30 years as representative of the current global fleet.

LNG terminals – 40 years. Cheniere Energy Partners, an LNG operation company, estimates a physical lifespan of 10 to 50 years for various components in LNG terminals, with longer lifespans for the most expensive items: 50 years for LNG storage tanks and 30 years for regasification and processing equipment [528]. We choose a midpoint of 40 years as our lifespan estimate. The *BEA FAA* depreciation scheme does not specify LNG terminals.

Oil storage – 30 years. Information on the service life of oil storage facilities (bulk terminals, tank farms, and the underground sites of the Strategic Petroleum reserve) is not readily available. Bulk terminals make up most of the value of oil storage infrastructure, and have long physical lifespans. A review of standards for marine oil terminals for the California Lands Commission estimates that the average age of waterfront oil terminals in California in 2012 is over 50 years, beyond their design life, with some facilities over 100 years old [529]. The Louisiana Offshore Oil Port (LOOP), the only U.S. deepwater terminal, was completed in 1981 (at a cost of $700 M in 1981 dollars, or $1.8 B in 2012 dollars), making it 31 years old in 2012 and 38 years in 2019 [530].

Tank farms may also remain in use for many decades. The oldest tanks in Cushing, OK (known as the "Pipeline Crossroads of the World" and collectively representing the largest aboveground oil storage facility in the U.S.) date to the 1920s [531]. The four sites of the U.S. Strategic Petroleum Reserve are younger, with construction first initiated in 1975 following the OPEC embargo during the Arab-Israeli war [296], and full operation in 1987-1991, giving a present (2019) age of ∼30 years. A 2012 annual report from MPLX Energy Logistics gives a general lifespan for oil storage and delivery facilities (excluding pipelines) of 24-37 years [532]. We adopt a midrange value of 30 years.

Note that federal and state taxation and depreciation guides generally suggest shorter financial lifetimes. Bulk terminals are assigned a 12 year lifespan in the Harris County, TX 2014 taxation and depreciation guide ("Business & Industrial Property Division Value Calculation Guidelines") [533]. Crude tank farms are assigned a 25 years lifespan in the Indiana state "Real Property Assessment Guidelines" of 2011 [534]. We assume these guides underestimate the actual physical lifespan of oil storage facilities.

Gas storage – 50 years. All natural gas storage involves underground facilities that should have long lifetimes, but estimates of those lifetimes are rare. Industry sources report that many U.S. depleted reservoir storage facilities are over 30 years old (Niska Gas Storage, [535]), though salt cavern facilities are younger (Exponent, an engineering and consulting firm specializing in underground gas structures, [536]). A 1992 environmental impact statement produced by the New York State Department of Environmental Conservation estimated that the 21 gas underground storage facilities then operational in New York had an average age of 30 years [537]. In a steady-state system, a 30-year mean age would imply a physical lifespan of 60 years, and the Swarts storage field in Pennsylvania, still operational in 2019, has been used since the 1950s, i.e. for about 60 years [538]. Retirements of major gas storage sites are not common enough to provide significant insight. The largest gas storage facility in the U.K., the Rough undersea depleted reservoir, was first operational for gas storage in 1985 and announced closure in 2017 after 32 years of official use [539]. We choose 50 years as a reasonable assumed service life.

Coal mines – 40 years. The age structure of coal mines in the U.S. is affected by amendments to the Clean Air Act of 1974 during the 1970s and early 1980s that increased demand for low-sulfur coal and spurred development of surface coal mines in the West [540]. Wyoming's North Antelope Rochelle Mine, for example, the largest coal mine in the world, opened in 1984 and is 35 years old as of 2019. The Mine Health and Safety Administration (MHSA) tracks production volumes from individual mines from 1983 onwards and so provides partial information on U.S. coal mine ages; of coal mines in the MHSA database active in 2017, around 70% of production comes from mines with no record of activity before 1983, i.e. age < 35 years, and 30% from older mines.[67] Considerably longer service lives are possible. A 2014 publication by Shafiee et al. reports characteristics and expected service lives for 20 Australian surface mines; the longest expected life is 90 years and the reserve-weighted expected life is 48 years (Table 2 in [320]). We choose a conservative 40 years for coal mine service lifetime.

We note that some literature estimates of coal mine and mine equipment service lifetimes do suggest somewhat shorter lifespans. A 2008 National Energy Technology Laboratory (NETL) coal cost modeling report estimated 5-30 years for mine equipment lifespan [Table 1 317], 10-30 years when discussing resource and financial lifespans, and up to 50 years for a financial lifetime inclusive of post-production reclamation [317]. The NETL report also cites a 1991 article in the *International Journal of Surface Mining, Reclamation and Environment* that gives 20 years as the design life for typical surface mines [541]. The BEA FAA does not separately specify coal mines; they are grouped with ore mines in the broad category of *Private nonresidential structures: Mining exploration, shafts, and wells – Other* with a 20 year financial life.

Rail – 50 years. Railroad tracks are long-lived and some track in the U.S. dates back to the 1920s. Studies of railroad sleepers (the crossties between the rails) suggest expected service lifetimes up to 60 years depending on the material [542–545], and the *BEA FAA* assigns a 54 year financial lifespan for railroad replacement track under *Private nonresidential structure: railroad replacement track and other railroad structures* [441].[68] We choose a conservative 50 years lifespan.

Gasoline stations – 20 years. Information on lifetimes of gasoline stations is limited, and they are not specified in the *BEA FAA* depreciation scheme. The IRS *MACRS* asset life tables use 20 years for "service station buildings used for marketing of petroleum" [517]. While building lifespans are typically longer, underground storage tanks degrade more quickly and must be replaced. Because the EPA's regulation of underground storage tanks has increased in stringency over time, we assume the *MACRS* value is likely close to the current expected lifespan.

[67] The MHSA database gives production volume per year for individual mines after 1983, allowing us to infer the period in which mines are active. We take as first operational year the earliest of the following metrics, matched by Mine ID number: the earliest year in which production volume is nonzero (from individual sheets of annual production 1983-2017, or from MHSA compiled production 1983-2017); the compiled earliest year in which employment count is nonzero; the MHSA compiled mine first active date; and the MHSA compiled union start date.

[68] The BEA also assigns 38 years to *Private nonresidential equipment: railroad equipment*, which constitutes a small portion of freight rail value.

Power plants. The *BEA FAA* aggregates all power plants together and assigns them a lifespan of 45/40 years (for assets constructed before/after 1946), under the category *Private nonresidential structure: Electric light and power*.[69] In practice, however, power plant lifespans differ strongly by generating technology. We therefore estimate service lifetime separately by technology.

- *Hydro – 60 years.* The simplicity of hydroelectric generators makes them extremely durable, and hydropower makes up the oldest part of the U.S. electrical system. The oldest hydro plant in the *EIA-860* database still operational in 2012 dates from 1891 (121 years old). The mean age of all U.S. hydropower is over 46 years and the physical lifespan must be longer, as few large facilities have ever been retired. We take 60 years as a reasonable estimate.

- *Nuclear – 60 years.* The first completed U.S. nuclear power plant, Oyster Creek in New Jersey, began operation in 1969 and was shut down in 2018, a lifespan of 49 years [546]. Most U.S. nuclear power plants are of similar vintage. Although nuclear plants in the U.S. originally received operating licenses of 40 years duration, the U.S. Nuclear Regulatory Council has by now granted extensions to 60 years for virtually all U.S. plants: 74% of nuclear plants in 2014 and nearly 90% in 2018 were licensed to 60 years [547, 548].

- *Coal – 50 years.* Coal-fired power plants are typically designed to last for at least 25 years without upgrades, and operational lifetime are typically extended well beyond 40 years with capital upgrades [549]. Retirements of U.S. coal plants provide guidance on their effective service lives. Analysis of *EIA-860* power generation surveys by Lawrence Berkeley National Laboratory (LBNL) suggests an age of 50–60 years for coal plants recently retired as of 2017 [550] and the EIA reports an average age of retiring coal power plants as of 2015 of 56 years [551]. We choose a conservative value of 50 years.

- *Gas – 30 years.* Service lives of most gas-fired power plants are shorter than those of coal-fired plants, if they involve gas turbines rather than steam turbines. The National Renewable Energy Laboratory (NREL) estimates a service life of only 30 years for natural gas combined cycle power plants [552], and a study by the Appraisal Institute of Chicago, IL estimates a 35 year lifetime for the broad category of all gas plants [553]. LBNL does find an age of 50–60 years for recently retired gas combustion turbines [550], but this value is somewhat misleading as a service life estimate because gas turbines need substantial maintenance on much shorter timescales, including complete replacement of many components. We conservatively assume a 30 year lifespan for gas plants.

- *Oil – 30 years.* Defining a single service life for oil-fired power plants is not particularly meaningful since the category includes widely different technologies, from short-lived diesel generators to long-lived petcoke plants whose lifespans should be similar to those of coal-fired power plants. We choose a lifetime that is roughly appropriate for more recent technologies, but this number is not well-founded. Note that the mean age of oil plants in the 2012 inventory is considerably larger (41 years). As discussed in Section H, oil generation is not an important part of the U.S. energy sector, and most existing infrastructure is aging and will not be replaced.

- *Wind – 25 years.* The National Renewable Energy Laboratory (NREL) uses a standard estimate of a 30 year capital recovery time for all non-hydro renewables in their Annual Technology Baseline [554], but this estimate is too broad to be an accurate representation of service life. Wind turbines in the U.S. are also generally too young for retirements to guide an estimate of their service life. The typical design lifetime for modern wind turbines is 20 years, meaning that many wind farms are nearing this limit soon, but that approaching deadline has also led to widespread interest in practices and standards

[69] Some power plant related equipment does appear in the *BEA FAA* in categories with shorter service lives: for example "electrical transmission, distribution, and industrial apparatus" at 33 years, "steam engines and turbines" at 22 years, and "internal combustion engines" at 8 years.

for extending turbine lifetimes [555, 556]. We choose 25 years assuming these efforts will be at least partially successful.

- *Solar – 25 years.* Solar photovoltaic facilities, like wind, are too young for retirements to guide an an estimate of service life. Solar PV modules do degrade over time, and many panels come with 20-year warranties that guarantee at least 80% of rated power production after 20 years of life (no more than 1%/year degradation) [557]. While some groups estimate a longer lifespan for panels – the International Renewable Energy Agency (IRENA) assumes 30 years in a 2016 report [558]– NREL notes that inverters must be replaced after 15 years [554]. We use 25 years as a reasonable estimate for system lifespan for utility-scale solar.

- *Geothermal – 25 years.* Some geothermal electricity generation plants, which make use of natural reservoirs of hot water, have demonstrated long lifetimes: for example, the Geysers in California has been operational since 1960, a useful life of over 50 years [559]. However, geothermal reservoirs are subject to depletion (loss of pressure), and engineering assessments estimate 25-30 years of typical service life [560]. For simplicity we assume a lifespan of 25 years, matching wind and solar.

Transmission and distribution power lines – 50 years. The U.S. electricity transmission and distribution infrastructure is aged, with many existing grid assets nearing the end of their expected lifespans. The American Society for Civil Engineering (ASCE) *2017 Infrastructure Report Card* states that "most electric transmission and distribution lines were constructed in the 1950s and 1960s with a 50-year life expectancy" [561]. A 2014 report from the Edison Electric Institute [562] estimates that around 30% of transmission infrastructure and 44% of distribution infrastructure is near the end of its service life. That service life is not specified, but this observation is consistent with a value of 50 years or more. Many other organizations have made at least partial assessments of the age structure of the electrical grid. For example, a 2004 textbook by Casazaz and Delea (*Understanding Electric Power Systems* [563]) estimates that a large portion of U.S. lines and substation equipment – including transformers and reactive components – are over 30 years old, with some reaching 75 years old.

Life cycle assessments in the literature and government permit applications concur in suggesting long physical lifespans: 35–50 years for transmission and distribution poles and towers [564]; 40–50 years for the lines themselves [565–567]; and up to 100 years for clearings, protective dikes and embankments [562, 568]. The physical life expectancy of the electrical grid thus appears considerably longer than the BEA FAA assignment of a 33 year financial lifespan (under the category of *Private nonresidential structure: Electrical transmission, distribution, and industrial apparatus*) We use a value of 50 years, based on the ASCE report.

Electrical substations – 40 years. Estimates of the service life of substations or of transformers, their major components, are typically lower than those of transmission and distribution lines. Life-cycle assessment studies and reported manufacturers' specifications assume transformer lives ranging from 25 to over 50 years [569–572], but a study of transformer lifespan estimated a value close to 40 years, and a 2013 thesis found a median transformer age in the U.K. of 40 years [573]. The International Council on Large Electric Systems also estimates a 40 year lifespan for substations as a whole [574]. We take this consensus 40-year value as our substation lifespan.

N. Analysis of cost per energy flow and per unit energy

To compare infrastructure costs for different types of energy usage, we convert inventory asset values to two different units: **cost per energy flow**, and **cost per unit of energy** delivered over the lifetime of an asset. The first metric (in units of **$/W**) measures capital intensiveness: the upfront cost of assets that support a given level of energy flow through them. The second metric (in **cents/kWh**) measures infrastructure contribution to energy prices. We calculate it by dividing the cost per flow through an asset by its service life, neglecting financing costs. Cumulatively adding this metric allows direct comparison to energy prices at different stages along the fuel production chain (Table 38). The comparison shows that our estimates are reasonable, and also highlights differences between fuels. Gas and oil have similar infrastructure costs relative to delivered fuel energy, but for gas those costs make up an astonishing 60-80% of the fuel price. (Oil prices are 5× higher, set by the global market.) U.S. natural gas prices were near historic lows in 2012, so much of gas infrastructure was installed in a different economic landscape.

	$/unit	cumul.	Ref. market price		Source
Oil	**$/barrel**				
domestic extrac.	13.9	13.9	95	Domestic crude oil first purchase price	[575]
foreign extrac.	17.3	17.3	100	Free onboard costs of imported crude oil, average	[576]
tankers	0.3	17.6	101	Landed costs of imported crude by area	[577]
extrac. avg		15.8			
refineries	1.2				
pipelines	0.4				
storage	0.6	18	130	Acquisition cost for the electric power industry	[578]
gas stations	1.5	20	146	Fuel prices, conventional gasoline areas	[312, Table 5.24]
Natural Gas	**$/MCF**				
domestic extrac.	2.1	2.1	2.7	Wellhead price	[579]
foreign extrac.	2.1	2.1	2.8	Pipeline imports price, by pipeline	[579]
tankers	0.17	2.3			
LNG terminals	3.2	5.4	4.3	Price of LNG imports, as liquefied natural gas*	[579]
extrac. avg		2.1			
processing plants	0.1				
pipelines	0.6	2.8	4.7	Acquisition cost for electric power	[579]
storage	0.1	2.9	3.5	Citygate price	[579]
Coal	**$/short ton**				
domestic extrac.	1.4		37	Price of coal by mine type, average	[580, Table 28]
railroads	2.9	4.3	46	Average price of coal delivered to electric power	[580, Table 34]
Electricity	**cents/kWh$_{\text{elec.}}$**				
generation (mean)	2.4	2.4	3.4	Average wholesale electricity price	[581]
t&d	1.1		2.8	Estimated cost of delivering electricity	[582, Table 2.4]
		3.5	9.8	Average retail electricity price	[583]

Table 38: Comparison of fuel price along the supply chain with the cumulative cost of infrastructure supporting the fuel flow. Cumulative costs should be lower, since we include neither financing nor O&M. Cumulative costs are calculated by summing infrastructure costs in cents per kWh of primary energy along the supply chain (from Table 39), and then converting units. Costs shown here include all relevant infrastructure, i.e. we do not adjust for unused capacity, assuming that all assets are neeeded to maintain the current energy system. This assumption is generally reasonable, but U.S. LNG terminals are overbuilt. Conversion factors are 5,892,000 BTU per bbl oil, 1,025,000 BTU per MCF natural gas, and 19,210,000 BTU per short ton coal [584, 585]; there are 3,412 BTU per kWh. In common units, infrastructure costs for oil, gas, and coal of $18/bbl, $3/MCF, and $4.3/short ton translate to 0.69, 0.94, and 0.08 cents per kWh of primary energy, respectively, and prices of $130/bbl, $4.7/MCF and $46/short ton translate to 7.5, 1.6, and 0.8 cents per kWh. That is, oil and gas have similar infrastructure costs per delivered energy, but oil price per energy is nearly 5× that of natural gas and 10× that of coal. We also compare the U.S. mean wholesale electricity price in cents per kWh of *electrical* (not primary) energy with the U.S. weighted mean infrastructure costs of generating and delivering electricity (from Table 41).

In the following, Section N.1 computes costs per primary energy for individual asset categories related to fossil fuel use (Tables 39-40 and Figures 50-51); Section N.2 sums cumulative capital costs for electricity generation by technology (including non-fossil) and calculates the U.S. generation-weighted average (Table 41); and Section N.3 provides calculation details.

N.1. Costs of individual asset categories per primary energy and flows

Table 39 below summarizes the cost per flow and cost per energy of individual asset categories. Sources for capacity and flow information are listed in Table 40. To help in comparison, we also sum costs for all upstream and midstream assets (listed in italics as *cumulative*; these cumulative values are those used in the price comparison of Table 38). Cumulative costs are also required to calculate the total infrastructure for electricity generation shown in Table 41, which includes not only the costs of the power plants themselves but of all upstream/midstream infrastructure associated with delivering fuel to the plant. For coal-fired electricity, upstream/midstream costs are negligible, and nearly all asset value is in the power plants. For natural gas electricity, upstream/midstream costs are nearly twice those of the actual power plants.

	Upfront value, $B	Service life	Power flow	Power capacity	Power, GW flow	Power, GW capacity	$/W flow	$/W capacity	cent/kWh flow	cent/kWh capacity
Oil			**M bpd**							
domestic extrac.	658	20	6.5		467		1.41		0.80	
foreign extrac. (net)	931	20	7.4		532		1.75		1.00	
tankers	18	30	4.9		353		0.05		0.02	
extract. avg							*1.61*		*0.56*	
pipelines	175	60	18.1		1,330		0.14		0.03	
rail cars	5.7	35	0.42		30		0.09		0.04	
refinery input	373	60	14.4	16.2	1,036	1,166	0.36	0.32	0.07	0.06
storage	126	30	18.5		1,330		0.09		0.04	
cumulative							*2.20*	*2.16*	*0.69*	*0.69*
gas stations	96	20	8.5		614		0.16		0.09	
elect. gen. (primary)	64	30	0.12	2.41	8.5	173	7.5	0.37	2.9	0.14
elect. gen. (elect.)					2.65	54	24.2	1.19	9.2	0.45
t&d (primary)	13	48			8.5		1.48		0.36	
Natural Gas			**TCF/yr**							
domestic extrac.	1,055	20	25.3		867		1.22		0.69	
foreign extrac. (net)	63	20	1.52		52		1.22		0.69	
carriers	1.02	30	0.20		6.96		0.15		0.06	
LNG terminal	19	40	0.15	6.8	5.02	232	3.7	0.08	1.05	0.02
extract. avg							*1.24*		*0.73*	
processing plants	48	35	17.5	23.5	601	807	0.08	0.06	0.03	0.02
pipeline	949	60	25.5		876		1.08		0.21	
storage	55	50	25.5		876		0.06		0.01	
cumulative							*2.46*	*2.44*	*0.94*	*0.93*
elect. gen. (primary)	488	30	9.61	33	330	1,145	1.48	0.43	0.56	0.16
elect. gen. (elect.)					140	486	3.49	1.01	1.33	0.38
t&d (primary)	667	48			330		2.02		0.48	
Coal			**M sh. tons/yr**							
domestic extrac.	57	40	1,016		653		0.09		0.02	
railroads	131	50	889		571		0.23		0.05	
cumulative							*0.32*	*0.32*	*0.07*	*0.07*
elect. gen. (primary)	1,092	50	827	1,610	532	1,035	2.05	1.1	0.47	0.24
elect. gen. (elect.)					173	336	6.3	3.2	1.44	0.74
t&d (primary)	823	48			532		1.55		0.37	

Table 39: Value of individual asset categories per energy flow and per energy delivered in $/W and $/kWh, using costs and capacities from the physical inventory, energy flows as described in Table 40, and service lives from Section M. Some average or cumulative values are given for reference (italics). Most values are given relative to primary energy, but those for electricity generation are also stated relative to electrical energy (in gray). Since thermal generation efficiencies are about 1/3, these values will be larger by about x3. Generation efficiencies are the flow of electricity out of generation assets (gray) divided by the flow of primary energy into them. Electricity flows and efficiencies are repeated in Table 41. Where possible, we give cost per both actual and potential flow through an asset category, using estimates of capacity. Differences can be large: for example, U.S. petroleum power plants generate electricity only at 5% of capacity, i.e. 95% of plants are not operating at any given time, so their cost per flow is 20x larger than cost per capacity. Minor categories like petroleum power plants can have cost per flow substantially larger than that of the overall U.S. energy system, $3.3/W. In final "t&d" category we allocate the transmission and distribution system to each fuel category according to its share of electricity generation f: upfront t&d value is the U.S. t&d total ($2201 T) $\times$ f. Service life for t&d is the weighted average of 50 years for power lines and 40 years for substations.

Table 40 below summarizes the sources used for the primary energy and electricity flows reported in Tables 39 and 41. Information is generally taken from EIA tables, and most flows are repeated from Tables 2 and 3.

	Energy flow source	Capacity source
Oil		
domestic extrac.	Table 2	
foreign extrac.	Table 2	
tankers	Sect. E.3.1	
pipelines	Table 2, consump. minus oil flow by rail	
rail cars		
refinery input	[33, 217]	[14]
storage	Table 2, consumption	
elect. gen. (primary)	[355, 584]	
elect. gen. (elect.)	[355]	[8]
gas stations	[328, Table 3.7c], consump. motor gasoline	
Natural Gas		
domestic extrac.	Table 2, wet prod.	
foreign extrac.	Table 2, net import	
gas carriers	Table 2, net LNG import	
LNG terminal	Table 2, net LNG import	[286]
processing plants	[586]	[15]
pipelines	Table 2, consump.	
storage	Table 2, consump.	
elect. gen. (primary)	[355, 584]	
elect. gen. (elect.)	[355]	[8]
Coal		
domestic extrac.	Table 3, prod.	
railroads	Table 3, consump.	
elect. gen. (primary)	[355, 584]	
elect. gen. (elect.)	[355]	[8]
Non-fossil Generation		
nuclear (elect.)	[133, Table 7.2a]	
hydro (elect.)	[133, Table 7.2a]	
wind (elect.)	[133, Table 7.2a]	
solar (elect.)	[133, Table 7.2a]	
Electricity Transmission and Distribution		
t&d (elect.)	[355, Table 1.1], net generation	

Table 40: Sources used in flows for \$/W and \$/kWh calculations.

In our choices here we seek to account fairly for the mingled oil and gas supply chains. The EIA considers natural gas plant liquids (NGPL) as natural gas, but after field processing, they are reclassified and considered part of the oil flow [587]. We therefore consider crude oil field production only (6.5M bpd) when assessing the oil extraction costs, but add natural gas liquids (2.4M bpd) downstream in the production chain. For natural gas production, we use the EIA's estimate of "wet" production (inclusive of NGPL), which adds an extra 5% to the dry gas flow. (See Table 2.) Note that our inventory distinction between oil and gas wells by GOR introduces slight biases: in Section B.5 we estimate that this convention depresses the cost of oil wells per energy produced by about 6% and increases that for gas wells by about 2%. For oil carried by tanker, we subtract pipeline-carried imports from Canada from U.S. net imports; see Section E.3.1. For refinery flow, we correct for export of refined products; see Section E.1. We assume for simplicity that oil pipelines carry all U.S. consumption other than the 5% of U.S. oil supply moved by rail in 2012. (The API estimates that two thirds of U.S. crude oil moves by pipeline [588], but this estimate does not account for product pipelines, and no sources readily permit an exact breakdown.) For gas pipelines, we use total consumption; the API estimates that 94% of gas is transported by pipeline [589]. For oil and gas storage, we use total consumption, since throughput data can be complicated by seasonal withdrawals.

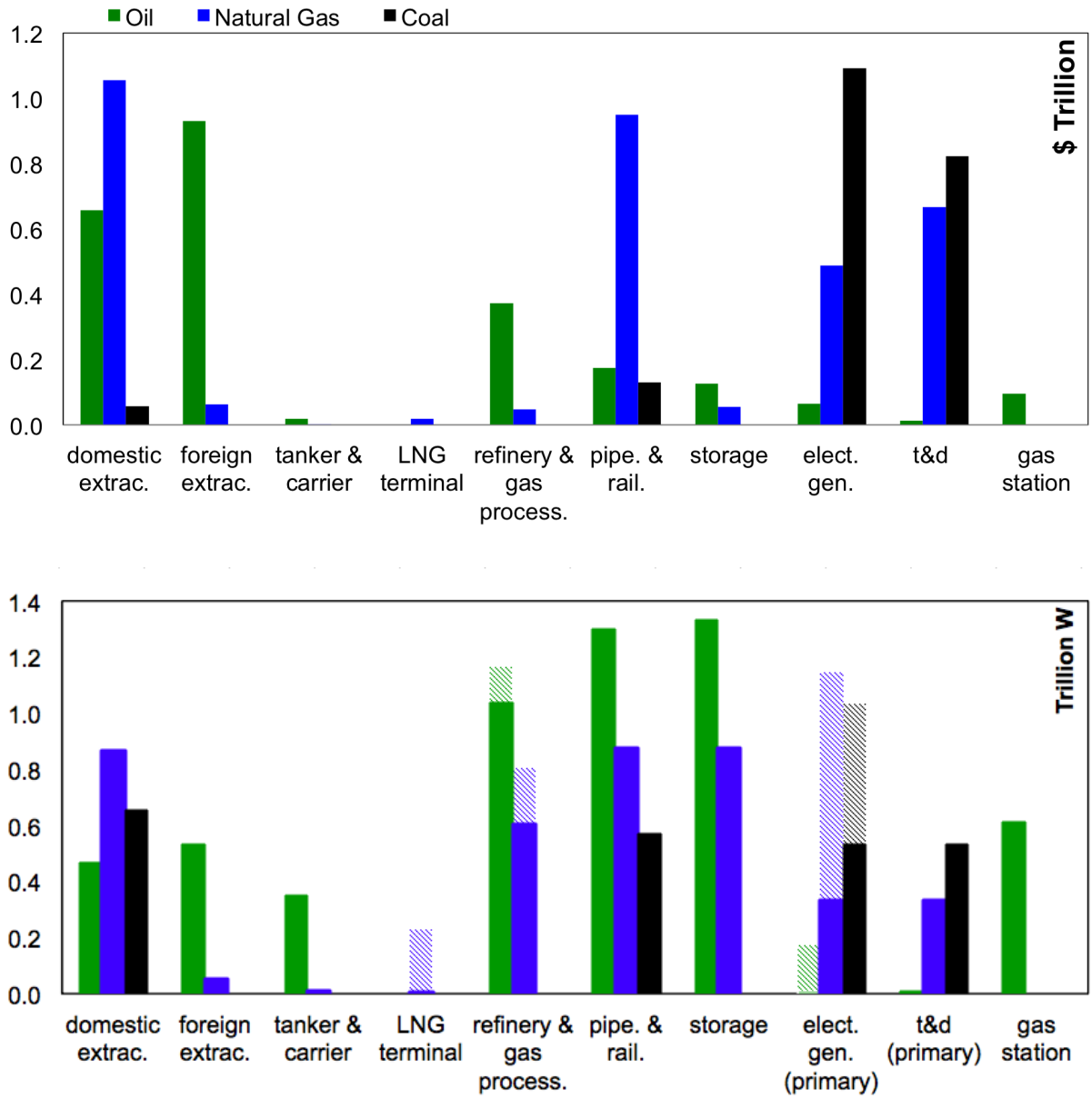

Figure 50: Characteristics of asset categories associated with fossil fuels: upfront values (**a**, in US $T, real 2012), and energy flows (**b**, in TW). All values are from Table 39, and Table 40 gives sources. In **b**, where utilization rate (capacity factor) is available we show flows both at actual current utilization (solid) and at full capacity operation (hashed). Other than in minor categories like LNG terminals, capacity factors play a large role only in power plants. Coal plants operate at ∼50% capacity, on average, gas plants at ∼30%, and oil plants at ∼5%. Transmission and distribution flows in **b** are the primary energy of each fuel type devoted to generating electricity. T&D asset values in **a** are the total system value ($2.2T) times the share of total electricity generated by each technology. While oil assets are primarily upstream (wells), and coal assets downstream (power plants), natural gas assets are spread throughout the production chain, with wells, pipelines, and power plants all within a factor of 2 in value.

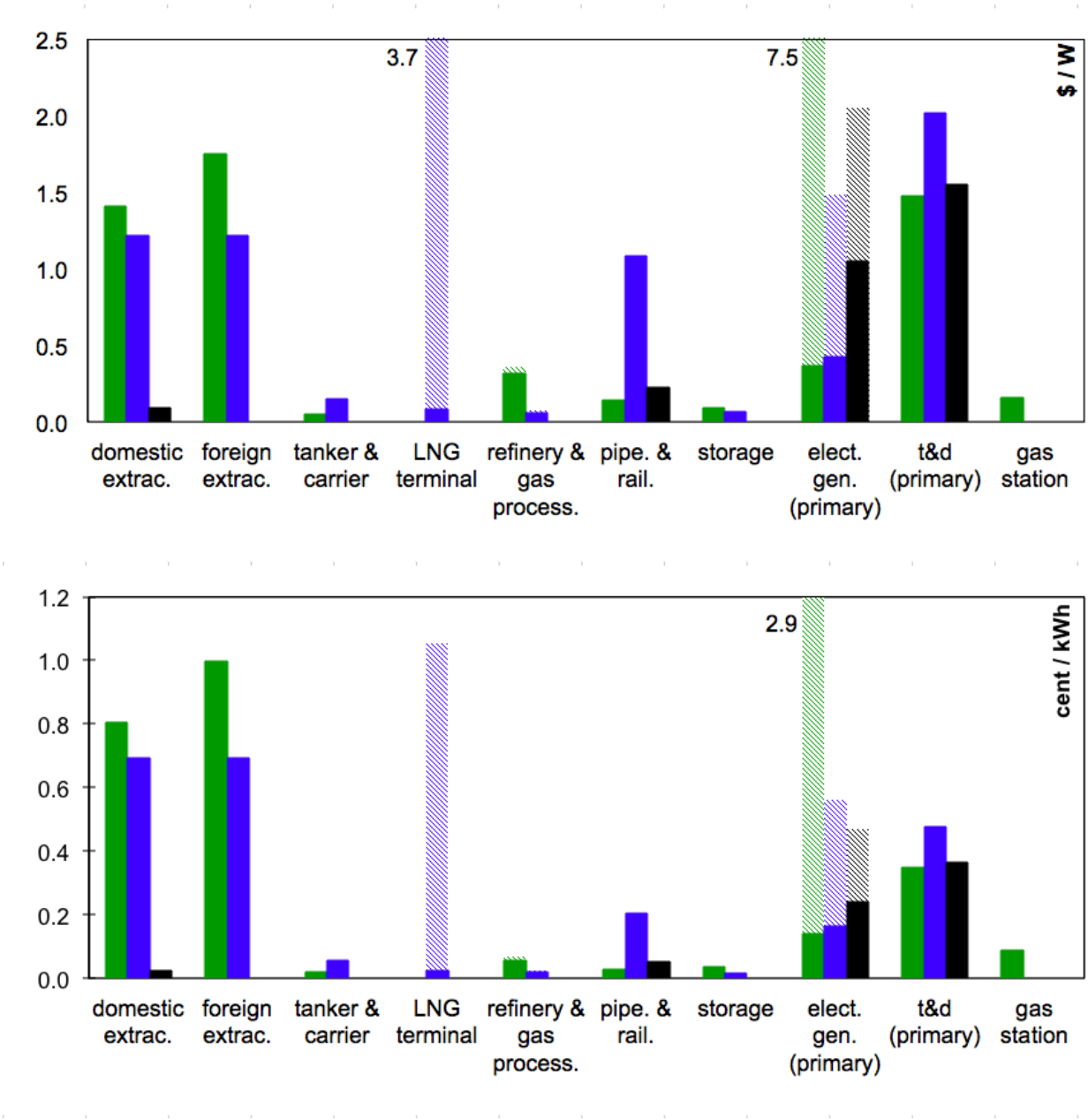

Figure 51: Derived asset value per energy flow (**a**) and per unit energy over the asset's lifetime (**b**). In **a**, asset cost per energy flow ($/W) is derived by dividing upfront asset values in Figure 50a by power rates in Figure 50b. Solid bars are cost if used at full capacity; hashed are at current utilization levels. (The convention is reversed from Figure 50.) Costs for some low-capacity asset classes extend off-scale; in these cases values are printed in figure. Normalizing by the flow highlights the infrastructure cost of converting fuel energy to electricity. Natural gas pipelines have greater total asset value than do gas power plants in Figure 50a, but power plants process less than half of U.S. natural gas, so their cost per flow is greater than that of pipelines. In **b**, cost per energy unit (cents/kWh) is derived by dividing the cost per flow in **a** by the service life of the asset from Section M. This normalization weights short-lived assets more heavily, making wells (20 years) the most expensive asset class and reducing the relative importance of long-lived assets such as pipelines (60 years), electricity transport (48 years), and coal power plants (50 years).

N.2. Costs of electricity generation per electrical energy and flows

Realistic proposals for transitioning the U.S. off fossil fuels involve electrifying much of the energy sector. That is, these proposals assume that that nearly all end uses of energy will occur as electricity, which is readily generated by non-fossil alternatives. It is therefore important to calculate the infrastructure cost of electricity generation. In Table 41 below we show these costs for all generation technologies.

Treatment of fossil and non-fossil sources differs. For non-fossil technologies, the only assets relevant to generation are power plants. (Technically nuclear power includes uranium mining, but we neglect that contribution as small.) For the fossil fuels, the upstream/midstream assets associated with delivering fuel to power plants are substantial. We add these costs (summed in Table 39 in "*cumulative*" rows) to those of power plants ("elect. gen. (primary)" rows), and then convert to units of cost per electrical energy:

$$C_{\text{foss. gen.}} = \left(\sum \frac{\text{upstream/midstream}}{\text{primary energy}} + \frac{\text{power plants}}{\text{prim. energy}}\right) \times \left(\frac{\text{primary energy in}}{\text{electrical energy out}}\right)$$

The second term here is $1/e$, where e is the dimensionless efficiency of the power plant.[70] For fossil turbo-generators e is typically $\sim 1/3$, so that cost per electrical energy is ~ 3 times that for primary energy. The capital costs of electricity generation can be counterintuitive. For example, nuclear and coal power plants are expensive, and so have the highest upfront power plant cost per capacity of any technologies (0.95 and 0.82 cents/kWh, vs. 0.38 for gas). However, nuclear and coal plants are operated at relatively high capacity factor and involve few upstream assets, while gas plants are often non-operational and involve substantial upstream assets. Total capital costs per electrical output are actually substantially lower for nuclear and coal than for gas (1.3 and 1.7 cents/kWh vs. 3.5 for gas).

	Upfront value, \$B	Service life	Power, $GW_{elec.}$ flow	capacity	Cap. factor	e	$\$/W_{elec.}$ flow	capacity	$cent/kWh_{elec.}$ flow	capacity
Generation, non-fossil										
Nuclear	597	60	87.8	108	0.81	1	6.8	5.5	1.3	1.1
Hydro	340	60	31.5	99	0.32	1	10.8	3.4	2.1	0.7
Wind	132	25	16.1	60	0.27	1	8.2		3.7	
Solar	14	25	0.49	3.22	0.15	1	28.6		12.9	
Generation, fossil										
Oil	(64)	(30)	2.65	54	0.05	0.31	31.6	8.5	11.5	2.8
Gas	(488)	(30)	140	488	0.29	0.42	9.3	6.8	3.5	2.6
Coal	(1092)	(50)	173	336	0.51	0.33	7.3	4.2	1.7	0.98
Generation, U.S. average						0.56	8.3		2.4	
Transmission and distribution										
T&D	2201	48	462				4.8		1.1	

Table 41: 2012 cumulative capital costs of electricity production for different technologies, in units relative to electrical (not primary) energy. Note that costs of wind and solar have declined since 2012. Costs in cents/kWh should be lower than the "levelized cost of electricity generation" (LCOE) since they do not include financing, O&M, and non-capital factors affecting fuel prices. See Table 40 for flow and capacity sources; these values are used to derive capacity factors. *Non-fossil.* We book-keep inputs to non-fossil generators as identical to outputs so efficiency is by definition 1. Capacity factors for wind and solar are defined based on the natural environment and can never reach 1. For wind, capacity is generation were the wind to blow optimally for the turbine at all times. For solar, it is generation were the sun to shine with average incident radiation 1000 W/m^2, impossible on Earth. We therefore do not compute cost per capacity for wind or solar. For nuclear, we neglect the small upstream costs of uranium mining. *Fossil.* Cost values include all upstream and midstream assets required to deliver fuel to the power plant, summed from Table 39 and converted from primary to electrical energy units by dividing by the generation efficiency. For comparison, we show in first two columns (in parentheses) asset values and service life for power plants alone, but these values are not used in the calculation. *U.S. average.* Categories shown here represent 98% of utility-scale U.S. electricity generation; we take their generation-weighted capital cost of 2.4 cents/kWh as the national mean. *T&D.* Service life for T&D is the weighted average of 50 years for power lines and 40 years for substations.

[70] The "heat rate" of a plant is its efficiency expressed in units of BTU/kWh: a perfect efficiency of 1 is a heat rate of 3,412.

N.3. Details of calculations

In this section above, we give asset values in units of \$/W (cost per flow of energy) and cents/kWh (cost per unit energy), and in two forms, as "by flow" and "by capacity". The former is the value of infrastructure used in the U.S. energy sector at its current utilization rate; the latter is the value were all infrastructure to be operating at 100% of capacity. Values in \$/W are calculated as:

per flow:

$$\frac{\text{Asset Value[\$]}}{\text{Energy Flow [W]}} \tag{4}$$

per capacity:

$$\frac{\text{Asset Value[\$]}}{\text{Capacity [W]}} \tag{5}$$

Values in cents / kWh are calculated by further normalizing by the asset service life. The denominator now represents the total amount of energy processed in an asset's lifetime:

per flow:

$$\frac{\text{Asset Value[\$]}}{\text{Energy Flow [W]} \times \text{Asset Service Life}} \tag{6}$$

per capacity:

$$\frac{\text{Asset Value[\$]}}{\text{Capacity [W]} \times \text{Asset Service Life}} \tag{7}$$

Energy flows

Energy flow data used in our estimates is mostly based on EIA compiled energy volume flows (*EIA volume flow*) [33–35]; full sources are shown in Table 40. Most values for the fossil fuels are also shown in Table 2. We convert all flows to common units of Watts using conversion factors of 5,892,000 BTU per bbl oil, 1,025,000 BTU per MCF natural gas, and 19,210,000 BTU per short ton coal [584, 585]; there are 3,412 BTU per kWh.

We do not consider loss of energy along the supply chain other that at power plants, where it becomes important since thermal power generators have efficiencies between ∼30-40% (Table 41). The EIA estimates the efficiency ("heat rate") of thermal generators each year. For consistency, we back out the fossil fuel input flows to electricity generation by combining EIA 2012 values for heat rates [584] with 2012 net generation by fuel category [355, Table 1.1]. Results are consistent to within 1% with EIA estimates of fossil fuel inputs to electricity generation [355, Chapter 2].

The only electricity flows included here are those which are marketed (added to the common grid). This category includes output of generators owned by electric utilities, independent power producers, and combined heat and power plants that have a grid connection. Industrial and residential generators that serve only a specific private site are excluded. This restriction on electrical output is consistent with the inventory assets totaled: the EIA-860 [8] database includes only grid-connected generators. Our cost per flow calculations are therefore internally consistent. Note that the assets involved in producing non-marketed electricity can be substantial in some cases. For example, as of 2012, natural gas plants that produce marketed electricity used about 9 TCF/year, but non-marketed power is estimated by the EIA to consume around 3 TCF/year [34]. Including non-grid-connected generators in our inventory would raise the value of gas generators in our inventory by about 1/3, or \$160 B.

Capacity

Capacity data used in our estimates is derived mostly from various EIA data series, and other authoritative sources, and is described in Table 40. Where relevant, we apply export corrections. For example, to quantify refinery capacity serving the U.S. market, we apply the same 89% factor used in export-adjusting refinery flows. For power plants, we use capacity from *EIA-860* [8]; when combined with EIA flows these produce utilization rates (capacity factors) slightly different from those in separate EIA estimates. For example, we obtain 51% for coal and 81% for nuclear (Table 41) vs. 56% and 87%, respectively in EIA tables [355, Table 6.07.A, Table 6.07.B] Note that our derived capacity factor for gas generation of 29% averages over technologies that have very different use characteristics: the EIA provides technology-specific estimates of 9% for combustion turbines and 53% for combined cycle in 2012 [355, Table 6.07.A]. Our capacity factor is similar to that of an EIA report describing overall gas generation utilization in the PJM market [590].

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P. References

Color code:

- black: academic journal articles, government agency reports, reports issued by industry (not advocacy) organizations in permanent form, data or reports submitted to courts or government agencies, technical reports
- blue: government data accessed online
- dark green: newspaper and magazine articles, NGO/advocacy articles and reports, slide presentations summarizing reports, unpublished conference proceedings, company reports and press releases
- light blue: personal communication and informal resources

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