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ScienceDirect
Journal of Policy Modeling 31 (2009) 404–424
Journal of Policy Modeling
www.elsevier.com/locate/jpm

Analysis of the Coal Sector under Carbon Constraints

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Received 4 May 2008; received in revised form 22 September 2008; accepted 30 September 2008
Available online 24 December 2008

Keywords: Carbon; Carbon capture and storage; EPPA model; Business-as-usual; Limited nuclear

1. Introduction

As an input to the MIT study of *The Future of Coal* (Ansolabehere et al., 2007) the MIT Emissions Prediction and Policy Analysis (EPPA) model was applied to an assessment of the fate of the coal industry under various scenarios of greenhouse gas mitigation and alternative assumptions about nuclear power growth and the future price of natural gas. A main determinant of the future of coal is the crucial role in climate policy of the application of carbon capture and storage (CCS) to coal-electric generation. Absent emissions controls, coal is the lowest cost fossil source for base-load electric generation. Also, coal resources are widely distributed among developed and developing countries, raising fewer security concerns than do oil and natural gas. These advantages, combined with regional interests tied to coal, make it highly unlikely that this fuel can be substantially removed from electric generation, so success in developing and implementing CCS technology is a priority objective in the management of climate risk.

In early applications of the EPPA model to studies of CCS a shortcoming became evident in the way electric generation was handled. For analysis of the aggregate performance of the electric sector and its emissions a simplified representation electric load dispatch (i.e., the allocation of different forms of generation to meet the electric load curve) was satisfactory. With a focus on specific technologies like CCS, however, a breakdown of electric demand among base, intermediate and peak-load service proved necessary.

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0161-8938/$ – see front matter
doi:10.1016/j.jpolmod.2008.09.005

The paper is organized in the following way. In Section 2 we discuss the method applied to represent load dispatch in the electric sector of this model. Section 3 presents several scenarios of coal use developed for *The Future of Coal* study but expanding the national coverage beyond the U.S. and China to include a wider group of countries. Section 4 focuses on the role of CCS technologies. We explore an expansion of the time horizon to 2100 also in Sections 5 and 6 concludes.

2. The MIT EPPA model

2.1. Model structure

In this analysis we apply the EPPA model, which is a multi-regional general equilibrium (CGE) model of the world economy (Paltsev et al., 2005). It is built on the economic and energy data from the GTAP dataset (Dimaranan & McDougall, 2002; Hertel, 1997), additional energy data from IEA (2005), and additional data for non-CO_2 greenhouse gases and other and urban gas emissions. The model version applied here distinguishes 16 countries or aggregate regions, six non-energy sectors, 15 energy extraction and conversion sectors and specific technologies, and includes a representation of household consumption behavior, as presented in Table 1.[1] This recursive dynamic model is solved on a 5-year time step to 2100, the first calculated year being 2005. Elements of EPPA model relevant to this application include its equilibrium structure, its characterization of production sectors, the handling of international trade, the structure of household consumption, and drivers of the dynamic evolution of the model including the characterization of advanced or alternative technologies, importantly CCS technologies.

The virtue of models of this type is that they can be used to study how world energy markets would adapt to a policy change such as the adoption of a carbon emission tax, the establishment of cap-and-trade systems, or implementation of various forms of direct regulation of emissions. For example, a carbon tax or cap-and-trade system would increase the consumer prices of fossil fuels, stimulating changes in consumer behavior and in the sectoral composition of production, causing a shift to low-carbon energy resources such as nuclear or fossil generation with CCS, and encouraging investment in more efficient energy use. A model like EPPA gives a consistent picture of the future energy market that reflects these dynamics of supply and demand as well as the effects of international trade. Its projections are, of course, dependent on its particular structure and the parameter estimates included so its value is in the insights to be gained from system behavior, not the details of particular numerical results.

2.2. Modification of the EPPA load dispatching algorithm

For the purpose of this analysis of coal and the role of CCS, three modifications are made to the representation of new technologies in EPPA's electric power sector: (a) the production structure of electricity from new dispatchable technologies is modified to include base-load, intermediate-load, and peak-load generation; (b) new fossil-based electricity generating technologies, such as supercritical pulverized coal and simple cycle gas turbine, are introduced; and (c) the bottom-up economic data of all new fossil generating technologies are updated. These modifications are discussed in detail below.

[1] The EPPA sub-model of fossil resource depletion, particularly of coal and natural gas, is important for this analysis. It is described in detail by Paltsev et al. (2005).

Table 1
Regions and sectors in the EPPA4 model.

Country/region	
Annex B	
	United States (USA)
	Canada (CAN)
	Japan (JPN)
	European Union+[a] (EUR)
	Australia/New Zealand (ANZ)
	Former Soviet Union (FSU)
	Eastern Europe[b] (EET)
Non-Annex B	
	India (IND)
	China (CHN)
	Indonesia (IDZ)
	Higher income East Asia[c] (ASI)
	Mexico (MEX)
	Central and South America (LAM)
	Middle East (MES)
	Africa (AFR)
	Rest of World[d] (ROW)
Sectors	
Non-energy	
	Agriculture (AGRI)
	Services (SERV)
	Energy Intensive products (EINT)
	Other Industries products (OTHR)
	Industrial Transportation (TRAN)
	Household Transportation (HTRN)
Energy	
	Coal (COAL)
	Crude Oil (OIL)
	Refined Oil (ROIL)
	Natural Gas (GAS)
	Electric: Fossil (ELEC)
	Electric: Hydro (HYDR)
	Electric: Nuclear (NUCL)
Advanced Energy Technologies	
	Electric: Simple Cycle Gas Turbine (GT)
	Electric: Natural Gas Combined Cycle (Adv. Gas)
	Electric: Gas Capture and Storage (Gas + CCS)
	Electric: Supercritical Pulverized Coal (Adv. Coal)
	Electric: Coal Capture and Storage (Coal + CCS)
	Electric: Wind and Solar (SOLW)
	Liquid fuel from biomass (BOIL)
	Oil from Shale (SYNO)
	Synthetic Gas from Coal (SYNG)

[a] The European Union (EU-15) plus countries of the European Free Trade Area (Norway, Switzerland, Iceland).
[b] Hungary, Poland, Bulgaria, Czech Republic, Romania, Slovakia, Slovenia.
[c] South Korea, Malaysia, Philippines, Singapore, Taiwan, and Thailand.
[d] All countries not included elsewhere: Turkey, and mostly Asian countries.

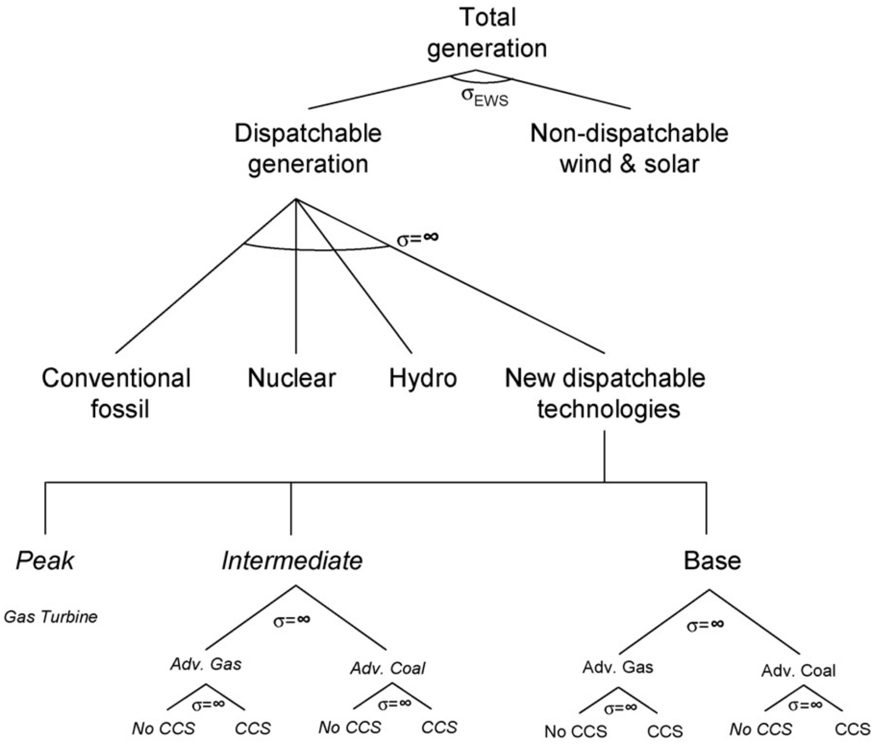

Fig. 1. Nesting structure of dispatchable electricity in EPPA.

Electricity demand varies over hours, days and months. Demand is higher during the day than at night, during the workweek than the weekend, and during summer and winter for cooling and heating than in spring and fall. These changes in demand influence the mix of technologies and fuels needed to instantaneously balance supply and demand on the power grid. To account for these changes in consumption and in supply mix we introduce base load, intermediate load and peak load to the production structure for electricity from new dispatchable generation technologies.[2] The combined supply from these different service levels is modeled as a perfect substitute for electricity generated using extant (conventional fossil, nuclear, and hydro) technologies which are not distinguished by position on the load curve. The sector structure is shown in Fig. 1 which details the nesting structure of these generation sources.[3]

Starting at the top of the nesting structure, total generation is comprised of dispatachable generation technologies and non-dispatchable wind and solar. Non-dispatchable generation, by definition, is not load following and is treated as an imperfect substitute for dispatchable generation (see Paltsev et al., 2005). The dispatchable generation bundle is made up of the following perfectly substitutable technologies: conventional fossil generation (*e.g.*, oil, gas and coal), nuclear, hydro, and new dispatchable technologies (*e.g.*, simple cycle gas turbines and advanced natural

[2] There are other examples of top-down models with electric dispatch. For example, Sands (2004) introduces peak and base-load generation into a top-down model, but without intermediate load and with fewer technologies.

[3] The growth of nuclear power is assumed here to be largely exogenous with minimal responsiveness to electricity price; see Table 4 for assumptions and Paltsev et al. (2005) for the exact specification.

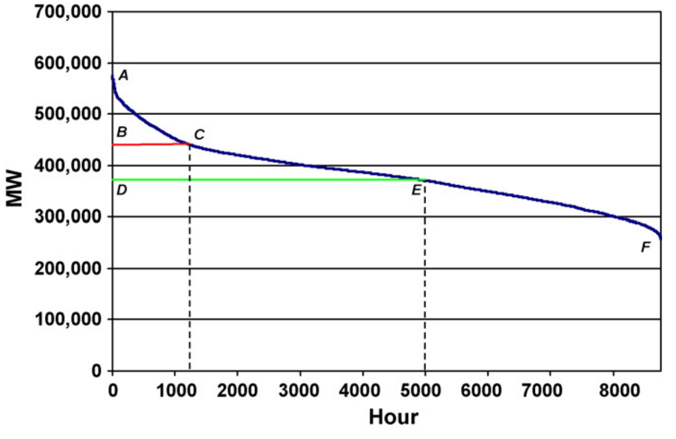

Fig. 2. Annual load duration curve for the U.S.

gas and coal technologies with and without CCS). Intra-annual demand variation for the extant technologies (conventional fossil, nuclear and hydro) is already accounted for in the base year data. As the simulation proceeds, older vintages of conventional generation (without the dispatching detail) are retired from use because investment in the new dispatchable sources with improved characteristics is more attractive.

For each of the new dispatchable technologies there is a further nesting of inputs as detailed in Paltsev et al. (2005) and McFarland and Herzog (2006). Peak generation technology is based upon a simple cycle natural gas turbine with low capital costs. Intermediate and base generation may be provided by advanced gas and advanced coal with or without CCS. The advanced gas technology is modeled after a natural gas combined cycle plant (see McFarland, Reilly, & Herzog, 2004). The advanced coal technology is based upon a supercritical pulverized coal plant. Advanced gas and coal with capture and storage are based upon post-combustion capture for gas and pre-combustion capture technologies for coal.[4]

To estimate the share of electricity assigned to each load segment, we use the annual distribution of demand for the U.S. as shown in the load duration curve in Fig. 2, plotted from highest load to lowest load (Hadley & Hirst, 1998). Although base-load, intermediate-load, and peak-load demand are common terms in the electric power literature, there are no precise definitions. In this analysis, peak load is defined as the demand for capacity that has to be met in the highest 1200 h per year (3.3 h per day) out of the total 8760 h in a year. This load is 441 GW in the calculations below and this peak service accounts for 2% of energy demand (area ABC in Fig. 2). Intermediate load is defined as the MW output in the top 5000 h per year (10.4 h per day) less the peak demand, or 370 GW, a level that comprises 6% of energy demand (BCDE in the figure). The remainder of the generation requirement is classified as base load and accounts for 92% of annual demand (the area under the curve DEF).

The EPPA model variables are in value terms, so the shares of base, intermediate, and peak generation required to produce a perfect substitute for generation from the extant technologies

[4] The expected cost differences between an integrated combined cycle plant with pre-combustion capture and an oxyfuel plant with post-combustion capture are within the range of uncertainty for each technology. Because these technologies are not treated separately, the model results apply to either technology or a mix.

Table 2
Cost data for gas turbine, advanced gas, and advanced coal technologies.

Technology	GT[a]	Advanced gas[b]		Advanced coal[c]	
Load segment	Peak	Intermediate	Base	Intermediate	Base
Capacity factor	14%	54%	85%	54%	85%
Capital ($ per kW)	460	510	510	1330	1330
Heat rate (Btu per kWh)	8550	6138	6138	8709	8709
Cost of electricity (cents per kWh)					
Capital	5.75	1.61	1.03	4.20	2.68
O&M	0.33	0.25	0.25	0.75	0.75
Fuel	4.28	3.07	3.07	1.26	1.26
Trans. and dis.	2.43	2.43	2.43	2.43	2.43
Total[d]	12.8	7.36	6.78	8.64	7.12
Mark-up	1.79	1.03	0.95	1.21	1.00

[a] Capital cost, operations and maintenance, and heat rate are from EPA (2005) and DOE (2004).
[b] Capital cost, operations and maintenance, and heat rate from Parsons (2002).
[c] Capital cost, operations and maintenance, and heat rate from Ansolabehere et al. (2007).
[d] Total and sum of cost of electricity may not be equal due to rounding.

are based upon the revenue stream in each load segment, not the share of electricity in physical units. Peak and intermediate electricity are more expensive than base generation because capital is amortized over fewer hours and more start-up and shutdown costs are incurred. We derive the value share for each load segment by running the Oak Ridge National Laboratory's ORCED model (Hadley & Hirst, 1998) for the U.S. The shares of revenue by load segment are fixed at 3% peak, 14% intermediate, and 83% base.[5] Currently, no substitution is permitted in the model between the three categories. Lacking region-specific data on hourly demand and prices, we apply the U.S. data to all EPPA regions in the results shown in Section 3.

The bottom-up cost information for generation technologies is presented in Table 2 (non-capture technologies) and Table 3 (capture technologies). Capital cost, heat rate, and operation and maintenance costs are taken from various sources (Ansolabehere et al., 2007; Parsons, 2002; US DOE, 2004; US EPA, 2005).[6] The capacity factors for peak (14%), intermediate (54%), and base (85%) generation are a product of the percentage of hours in a year for the particular load segment and plant availability. The reference energy prices for 1997 for coal and gas are assumed to be $1.44 and $5.00 per MMBtu, respectively. We assume a cost of 2.43 cents per kWh for electricity transmission and distribution and $10 per tCO_2 for the cost of CO_2 transport and storage (McFarland et al., 2004).

The cost of electricity for each type of generation in each region is calculated using the methodology outlined by David (2000). Plant capital costs are annualized using a 15% capital charge rate. The factor shares of capital, labor, and fuel are computed as shares of the total cost of electricity

[5] In McFarland, Paltsev, and Jacoby, (2008) we test the sensitivity of the results to changes in the value shares of peak, intermediate, and base demand.

[6] The costs of all generation technologies have risen substantially within the last few years. These cost increases are consistent with historic short-term cost oscillations in the power sector due in part to commodity price fluctuations and scarcity in specialized engineering and labor. In this study we assume that over time these costs will revert to their long-run averages.

Table 3
Cost data for advanced gas with capture and advanced coal with capture[a].

Technology	Advanced gas + capture[b]		Advanced coal + capture[c]	
Load segment	Intermediate	Base	Intermediate	Base
Capacity factor	54%	85%	54%	85%
Capital	1084	1084	1893	1893
Heat rate	6991	6991	10223	10223
Cost of electricity (cents per kWh)				
Capital	2.86	1.82	5.98	3.81
O&M	0.75	0.75	1.02	1.02
Fuel	3.50	3.50	1.48	1.48
Trans. and dis.	2.43	2.43	2.43	2.43
CO_2 trans. and stor.	0.19	0.19	0.43	0.43
Total[d]	9.72	8.69	11.33	9.17
Mark-up	1.36	1.22	1.59	1.28

[a] The bottom-up cost data used in this analysis are higher than that used in Paltsev et al. (2005).
[b] Capital cost, operations and maintenance, and heat rate from Parsons (2002).
[c] Capital cost, operations and maintenance, and heat rate from Ansolabehere et al. (2007).
[d] Total and sum of cost of electricity may not be equal due to rounding.

using the methodology described in McFarland et al. (2004). The nesting structure for the technology production functions and corresponding elasticities may be found in Paltsev et al. (2005). The mark-up for each technology is calculated as the ratio of its cost of electricity to the cost of base-load pulverized coal and reflects the cost of electricity relative to base-load coal within a given region. Note that the intermediate and peak-load technologies have higher mark-ups than the base-load technologies because the capital costs are spread out over fewer hours of generation. Additionally, the gradual penetration rates for newer technologies (*i.e.*, advanced gas, advanced gas with CCS, and advanced coal with CCS) are implemented using a technology- and region-specific specialized resource factor that grows endogenously based on the previous period's output, as described in Paltsev et al. (2005) and Jacoby, Reilly, McFarland, and Paltsev (2006, pp. 626).[7]

3. Scenarios of coal futures

3.1. Cases for analysis

To explore the potential effects of carbon policy we employ the three cases used in *The Future of Coal*: a reference or *Business-as-usual* (*BAU*) case with no emissions policy beyond the first Kyoto period, and two cases involving the imposition of a common global price on CO_2 emissions.[8] The two policy cases, *Low* CO_2 *price* and *High* CO_2 *price*, are shown in Fig. 3, with the CO_2

[7] The growth in the specialized resource factor is calibrated to mimic the experience of other centralized generating technologies, particularly that of nuclear power from the 1960s through the 1980s. The specification of the resource factor is identical across all of the new dispatchable technologies and regions. An earlier specification appears in McFarland et al. (2004).

[8] Additional scenarios reflecting China's increased coal use are explored in Paltsev and Reilly (2007). Economic implications of greenhouse gas stabilization are explored in US CCSP (2007).

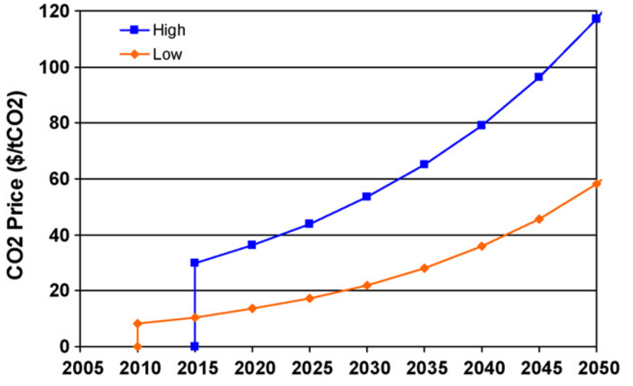

Fig. 3. Scenarios of penalties on CO_2 emissions ($/t$CO_2$).

penalty stated in terms of 2005 $US/t of CO_2. This penalty or emissions price can be thought of as the result of a global cap-and-trade regime, a system of harmonized carbon taxes, or even a combination of price and regulatory measures that combine to impose equal marginal penalties on emissions. Throughout the analysis universal participation is assumed: *i.e.*, the same emissions price applies to all nations. The *Low* CO_2 *price* profile corresponds to a proposal of the National Commission on Energy Policy, which we represent by applying its maximum or "safety valve" cap-and-trade price (NCEP, 2004). It involves a penalty that begins in 2010 with $8 per t$CO_2$ and increases at a rate of 5% per year thereafter. The *High* CO_2 *price* case assumes the imposition of a larger initial charge of $30 per t$CO_2$ in the year 2015 with a rate of increase of 4% thereafter.[9] One important difference to be explored in the comparison of these two cases is the time when CSS technology may take a substantial role as an emissions reducing measure.

A second influence on the role of coal in future energy use is competition from nuclear generation, and again two cases from the MIT *The Future of Coal* study are considered, shown in Table 4. In a *Limited nuclear* case, it is assumed that nuclear generation, from its year 1997 level in the EPPA database of 2.39 million GWh, is held to 2.43 million GWh in 2050. The alternative case, denoted as *Expanded nuclear*, assumes that nuclear capacity grows by roughly a factor of three and generation reaches 7.4 million GWh over this period—a level estimated as possible in *The Future of Nuclear Power* (Ansolabehere et al., 2003) if certain cost, waste and proliferation concerns can be met.

The third sensitivity test below explores the evolution of natural gas prices. The EPPA model includes a sub-model of resources and depletion of fossil fuels including natural gas, and one scenario, denoted *EPPA-Ref gas price*, is the model's own projection of gas prices (which differ by model region) under the supply and demand conditions in the various simulations. In the *BAU* case with *Limited nuclear* generation, the U.S. gas price is projected to rise by 2050 by a factor of 3.6 over the base year price, which implies a price of around $10 per million cubic feet (Mcf) in 2050 in 2005 dollars. To test the effect of substantial new discovery and development of low-cost LNG transport systems, a *Low gas price* case is explored. In this case the EPPA gas transport sub-model is overridden by a low-cost global transport system which leads to lower prices in

[9] The carbon prices are converted from 1997 dollars used by Ansolabehere et al. (2007) to 2005 dollars using chain-weighted dollars from the Bureau of Economic Analysis's National Income and Product Accounts.

Table 4
Alternative cases for nuclear generation (million GWh per year).

Region	1997[a]	2050[b]	
		Limited	Expanded
USA	0.67	0.58	2.23
Europe	0.92	0.94	1.24
Japan	0.32	0.42	0.48
Other OECD	0.17	0.10	0.34
FSU and EET	0.23	0.21	0.41
China	0.01	0.00	0.75
India	0.01	0.00	0.67
Other Asia	0.04	0.19	0.57
Rest of World	0.02	0.00	0.74
Total	2.39	2.43	7.44

[a] IEA (2007).
[b] Scenarios from Ansolabehere et al. (2007).

key heavy gas-consuming regions. For example, with the *Low gas price* scenario the 2050 price multiple for the U.S. is only 2.4 over the base year or a price of \$6.60 per Mcf in 2005 dollars.

3.2. Coal use assuming CCS is available

In order to display the relationships that underlie the future evolution of coal use we impose a policy scenario where CCS is available on an economic basis and all nations adopt, by one means or another, the carbon emissions penalties as shown in Fig. 3. In the EPPA model projections such emissions penalties would be sufficient to stabilize global CO_2 emissions in the period to 2050. This result is shown in Fig. 4 on the assumption of *Limited nuclear* generation, and *EPPA-Ref gas price*. With no climate policy, global energy-related emissions are projected to rise to 70 $GtCO_2$ per year by 2050. Under the *High* CO_2 *price* scenario, by contrast, global emissions are stabilized by around 2025 at level of about 30 $GtCO_2$. If only the *Low* CO_2 *price* path is imposed, emissions would not stabilize until around 2045 at a level of approximately 44 $GtCO_2$ per year.

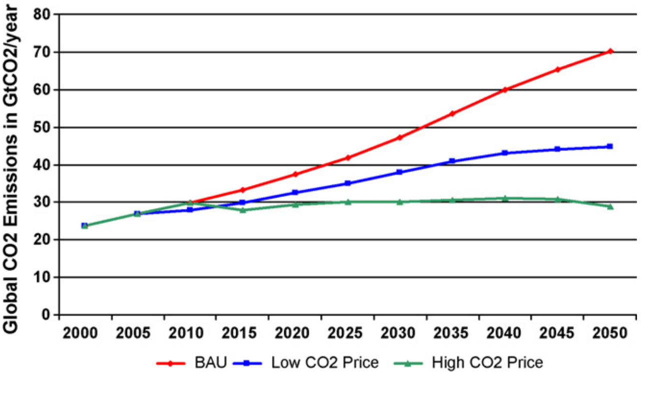

Fig. 4. Global CO_2 emissions under alternative policies with universal, simultaneous participation, *limited nuclear* and *EPPA-ref gas prices* ($GtCO_2$ per year).

Table 5
Implications for global coal use of alternative CO_2 prices[a].

Indicator	*BAU*		*Low* CO_2 *price*	*High* CO_2 *price*
	2000	2050	2050	2050
Coal consumption (EJ per year)	100	448	200	161
Coal CO_2 emissions ($GtCO_2$ per year)	9	40	17	5
% Coal consumption by CCS	0%	0%	4%	60%
% CO_2 emissions from coal	38%	57%	38%	19%

[a] Universal, simultaneous participation, *Limited nuclear* and *EPPA-Ref gas prices*.

3.2.1. The effect of CO_2 prices

A global picture of coal use under these alternative CO_2 price assumptions, assuming *Limited nuclear* capacity and *EPPA-Ref gas prices*, is shown in Table 5. In the absence of climate policy, coal consumption grows from 100 EJ in 2000 to 448 EJ in 2050. Under the *Low* CO_2 *price* trajectory coal's contribution to 2050 global emissions is lowered from 40 to around 17 $GtCO_2$ per year while total coal consumption falls to 45% of its no-policy level (though 100% above its 2000 level). The contribution of CCS is relatively small in this case because at this price trajectory CCS technology does not become economic until around 2035 or 2040, leading to a small market penetration, 4% of coal use by 2050. The picture differs substantially under the assumption of a *High* CO_2 *price* pattern. The contribution of coal to 2050 CO_2 emissions is projected to fall by 66% under the lower price path, yet coal use falls by only another 20% (and still remains 61% above the 2000 level). The large reduction in emissions from coal coupled with a smaller reduction in consumption points to the adoption of CCS technologies as shown in the third line of the table. With higher CO_2 price levels early in the simulation period CCS has time to take a larger market share and accounts for 60% of coal consumption in 2050.

The point to take from Table 5 is that CO_2 mitigation policies at the level tested here will limit the expected growth of coal and associated emissions but not necessarily constrict the industry below today's level. Also, the long-term future for coal use and the likely achievement in CO_2 emissions abatement are sensitive to the development and public acceptance of CCS technology and the timely provisions of incentives for its commercial application. For cases of still greater emissions reduction by 2050 the prospects for coal are even more dependent on the pace of CCS development; for example see the effects of 50–70% reduction in the U.S. explored by Paltsev et al. (2007).

Table 6 provides global and country-level coal consumption for all scenarios of CO_2 prices, gas prices and nuclear expansion. The countries listed include the top four coal using countries in 2050 (China, U.S., India, and Japan) and two aggregate regions, the Europe Union and the former Soviet Union. These countries and regions account for at least 60% of global coal use in 2050 across all of the scenarios.[10] China and the U.S. accounted for over 50% of global consumption in 2000 at 28 and 24 EJ, respectively. Europe, India, and the FSU each accounted for between 7 and 10 EJ of coal consumption while Japan consumes 3.6% of the total. Under the *BAU* case with *EPPA-Ref gas prices* and *Limited nuclear* coal consumption in China rises by a factor of 3 to 88 EJ in 2050 while U.S. consumption grows by 140% to 58 EJ. Consumption in India, the EU and

[10] The inclusion of the regions AFR, MES, LAM, ASI, and ROW, as defined in Table 1, would account for 90% of all coal consumption under all of the scenarios.

Table 6
Coal use under different assumptions, universal simultaneous participation (EJ).

Scenario		Region	*BAU*		*Low* CO_2 *price*	*High* CO_2 *price*	Index 2050–2000		
Gas price	Nuclear		2000	2050	2050	2050	*BAU*	Low	High
EPPA-Ref	Limited	Global	100	448	200	161	4.5	2.0	1.6
		USA	24	58	42	40	2.4	1.8	1.7
		China	28	88	37	39	3.1	1.3	1.4
		India	7.3	41	25	22	5.6	3.4	3.0
		Europe	10	36	17	5.8	3.6	1.7	0.6
		FSU	7.1	30	4.8	7.1	4.2	0.7	1.0
		Japan	3.6	15	12.2	5.1	4.2	3.4	1.4
EPPA-Ref	Expanded	Global	99	405	158	121	4.1	1.6	1.2
		USA	23	44	29	25	1.9	1.3	1.1
		China	26	83	30	31	3.2	1.2	1.2
		India	7.2	35	18	14	4.9	2.5	1.9
		Europe	10	33	13	5.4	3.3	1.3	0.5
		FSU	7.1	28	4.8	6.9	3.9	0.7	1.0
		Japan	3.6	14	9.6	4.6	3.9	2.7	1.3
Low	Limited	Global	100	438	162	111	4.4	1.6	1.1
		USA	24	53	12	14	2.2	0.5	0.6
		China	27	84	15	39	3.1	0.6	1.4
		India	7.3	39	4.7	2.1	5.3	0.6	0.3
		Europe	10	36	29	5.9	3.6	2.9	0.6
		FSU	7.1	30	7.2	17	4.2	1.0	2.4
		Japan	3.6	14	11	5.0	3.9	3.1	1.4
Low	Expanded	Global	99	397	129	89	4	1.3	0.9
		USA	24	41	14	17	1.7	0.6	0.7
		China	26	80	13	31	3.1	0.5	1.2
		India	7.2	32	2.4	1.2	4.4	0.3	0.2
		Europe	10	33	26	5.6	3.3	2.6	0.6
		FSU	7.0	28	5.9	7.8	4.0	0.8	1.1
		Japan	3.6	14	7.8	4.4	3.9	2.2	1.2

FSU grows to between 30 and 40 EJ with the fastest growth occurring in India (460%).[11] Japan's consumption quadruples to 15 EJ over this time.

Similarly, there is a strong regional variation in coal use changes due to a carbon policy, which can be seen in the top panel of Table 6 for *EPPA-Ref gas prices* and *Limited nuclear* scenario. For example, under *Low* CO_2 *price*s the coal consumption in the FSU exhibits the greatest decline, 84%, to 4.8 EJ, as natural gas substitutes for coal in the electric power sector. Europe undergoes a similar transformation in the electric power sector, but coal consumption declines by only 50% to 17 EJ. Under *High* CO_2 *prices* the FSUs coal consumption falls by only 76% because the *High* CO_2 *prices* stimulate earlier adoption of CCS technologies. Conversely, the EU increases its reliance on natural gas to the detriment of coal-fired generation. Coal consumption drops by 84% to 6 EJ.

[11] In the no policy case, coal use in the remaining regions grows by nearly 800% from 21 EJ in 2000 to 180 EJ in 2050. In most of these regions this increase is attributable to coal use in the electric sector.

Although China's and India's coal consumption grows faster than that of the U.S. without policy, a CO_2 charge yields a greater percentage reduction in these countries than in the U.S. By 2050 the *High* CO_2 *prices* have reduced Chinese use by 56% to 39 EJ and Indian use by 46% to 22 EJ. However, U.S. consumption is reduced by only 31% to 40 EJ. The main reason for the difference in response is the composition of coal consumption, and to a lesser extent a difference in the thermal efficiency of the electric power sectors, of these countries. By 2050 in the reference scenario (*EPPA-Ref gas prices* and *Limited nuclear*) China and India consume 48 and 27% of coal in non-electric power sectors compared with only 5% in the U.S. Under the *High* CO_2 *price* policy, China's share of coal consumption in the other sectors declines to 12% and India's to 4% while U.S. share drops two percentage points. Furthermore, within the electric sector, U.S. power plants are relatively more thermally efficient than in China and India so opportunities to lower coal consumption in China's and India's power sectors are greater. The *Low* CO_2 *price* policy has very similar effects in these three regions. In percentage terms, Japan is the most sensitive to the different carbon price paths. In the *Low* CO_2 *price* case, consumption declines by 20% to 12 EJ. The *High* CO_2 *price* path causes a much greater substitution of natural gas for coal in the power sector as coal consumption declines to by 66% to 5 EJ.

3.2.2. The effect of Expanded nuclear

The second panel of Table 6 displays the effect on the coal use of alternative assumptions about the expansion of nuclear power. Nuclear electricity growth at the level assumed in the *Expanded nuclear* case directly displaces electricity from coal. For example, under *BAU* the provision of *Expanded nuclear* generation reduces 2050 global coal by 10% from 448 to 405 EJ. The regional effects of *Expanded nuclear* on coal use range from declines of 24 and 15% in the U.S. and India, respectively to 6–8% in the other listed regions.[12]

The reduction in coal use is magnified by CO_2 prices. Under both the *Low* CO_2 *price* and *High* CO_2 *price* cases, *Expanded nuclear* scenario lowers global coal consumption by roughly 20% from the *Limited nuclear* case to 158 and 121 EJ, respectively. Consumption in the U.S. and India falls by approximately 30% to 29 EJ and 18 EJ with low CO_2 prices and under 40% to 25 EJ and 14 EJ with *High* CO_2 *prices*. China's coal consumption drops by 20% under both price paths to 30 EJ. Similarly, nuclear expansion with low CO_2 prices in the EU and Japan reduces coal use by roughly 20% (relative to *Limited nuclear* expansion with *low* CO_2 *prices*), yet with *High* CO_2 *prices* consumption drops by only 7–10% (relative to *Limited nuclear* expansion with *High* CO_2 *prices*). At *High* CO_2 *prices*, coal consumption is already very low in the EU and Japan, and nuclear primarily displaces electricity from natural gas. Coal consumption in the FSU is essentially unchanged by the expansion of nuclear power because nuclear substitutes for gas generation there.

Fig. 5 provides more detail of the generation patterns underlying these results, showing the effect of the imposition of *High* CO_2 *prices* and the effect of alternative patterns of nuclear expansion. Notable in the Fig. 5 is the fact that conventional fossil generation (*i.e.*, that existing in 2000) almost has been retired and the new dispatchable technologies (plus hydro) remain. Also, *High* CO_2 *prices* lead to the application of capture and storage in some regions but to replacement of coal by natural gas combined cycle generation in others, with the dominant use of CCS being in the U.S. and China. By 2050 coal CCS is beginning to grow in Europe and it does not enter in Japan until 2055. Europe and Japan have two of the more energy efficient conventional power

[12] The effect of expanded nuclear is similar under the low gas price case.

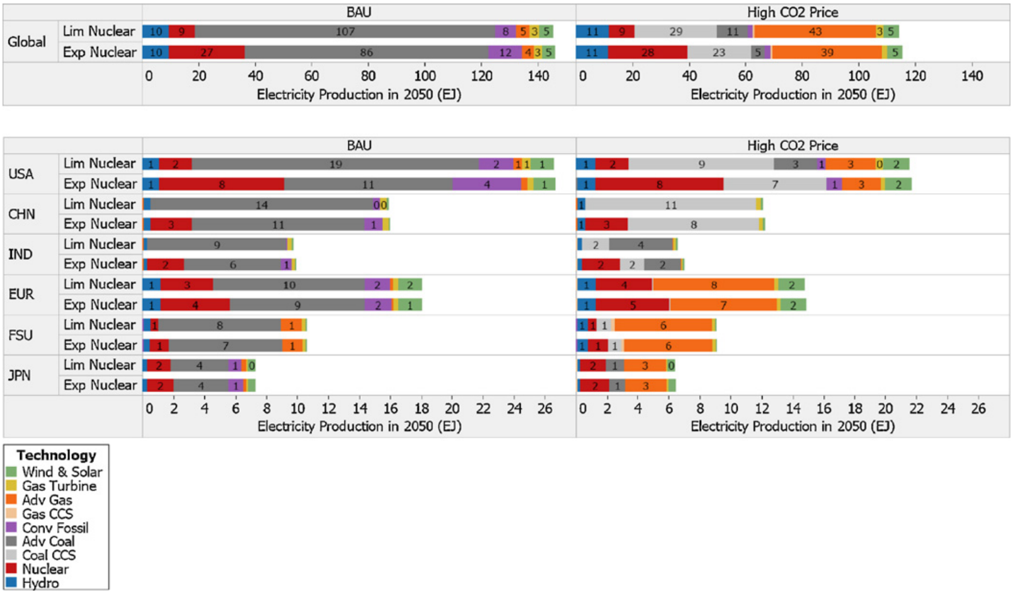

Fig. 5. Electricity production in 2050 under alternative policies with universal, simultaneous participation, *EPPA-Ref gas prices*, *Limited nuclear* and *Expanded nuclear* (EJ per year).

sectors. Furthermore, both regions are large importers of this fuel in the base year which enables them to switch a greater share of their electricity production to natural gas.[13] These factors make natural gas generation more competitive with coal CCS in these two than in other regions. Natural gas dominates CCS in the FSU because of its large domestic gas resources.

3.2.3. The effect of low gas prices

The results of the *Low gas price* scenario, presented in Table 6, show more regional variability in terms of coal use because the price changes are greater in some regions than others, and the availability of low-cost gas has a positive effect on economic growth. In the *BAU* case, lower gas prices have a small negative effect upon global coal consumption. Although coal competes with natural gas in the electric power sector, low natural gas prices have a stimulating effect on national economies. Thus the substitution of coal for gas is mitigated by the countervailing increased demand for electricity and output from other coal using sectors. In 2050, global coal consumption declines by a mere 2% to 438 EJ. The effect is greater in the U.S. and Japan as consumption declines by 9 and 7% as advanced gas generation displaces coal. A 5% decline is seen in both China and India. Coal use in the EU and FSU is unchanged. As described above, the *Low gas price* scenario treats gas as perfectly fungible commodity across regions much like today's global oil market. Although natural gas prices are lower in most regions, prices in the EU and FSU rise by 20 and 35%, respectively as other regions compete for the cheap gas previously available in these two regions. All other factors being equal, we would expect the higher gas prices to depress these economies and lower coal demand. However, the stimulating effect of lower gas

[13] In part this result is a feature of the EPPA model structure, which is based on constant elasticity of substitution (CES) functions (Paltsev et al., 2005). The share-preserving tendency of this equation form enables gas growth (by imports) in these two regions while restraining it in other regions.

prices in the other regions raises consumption in all regions, offsetting the negative impact of higher domestic gas prices in the EU and FSU. Coal demand in these two regions is therefore unaffected.

The effects of the *Low gas price* scenario on coal consumption under carbon prices are more complex. With *Low* CO_2 *prices* global coal consumption falls by 19% to 162 EJ in 2050 versus the scenario with *EPPA-Ref gas prices*. However this statistic hides the dramatic differences across regions. China, the U.S., and India experience dramatic declines of 59, 71, and 81%, respectively. However, coal consumption in the EU and FSU is 71 and 50% higher due to the stimulating effect low gas prices have on growth in these economies. Japan witnesses a small drop in coal consumption of 10%. *High* CO_2 *prices* in combination with *Low gas prices* reduce global coal consumption by 31% from 161 EJ (*High* CO_2 *prices* and *EPPA-Ref gas prices*) to 111 EJ. In the U.S., China, and FSU the *High* CO_2 *price* path leads to greater coal consumption than under the *Low* CO_2 *prices*. As explained in Section 3.3, this result is due to earlier adoption of CCS technologies in these regions. *Low gas prices* and the high CO_2 penalty reduce consumption in India by 90% to 2 EJ. The lower gas prices and *High* CO_2 *prices* lead to minor changes in consumption in the EU and Japan.

3.2.4. The combined effect of low gas prices and Expanded nuclear

The bottom panel of Table 6 depicts the greatest threat to the future of coal: *Expanded nuclear* with *Low gas prices*. In the *BAU* case, global coal consumption declines from the reference case by 11% to just under 400 EJ. Consumption in the U.S. and India declines by 29 and 22%, respectively. China, the EU, FSU and Japan reduce consumption by between 7 and 9%. These results are similar to those from the *EPPA-Ref gas*, *Expanded nuclear* case. This reinforces nuclear energy's role as a direct substitute for coal in the absence of carbon prices.

Global coal consumption grows very slowly under *Low* CO_2 *prices*, from 100 to 130 EJ over 50 years, or actually declines by 10 EJ from 2000 levels. With *High* CO_2 *prices*, coal use declines 78% compared to the *EPPA-Ref gas prices*, *Limited nuclear* case. Regionally, *Low* CO_2 *price* cases lower coal consumption by over 80% in China (13 EJ) and India (2.4 EJ) and over 75% in the U.S. (14 EJ) and FSU (6 EJ). Europe and Japan are slightly less affected with respective reductions of 21 and 44%, respectively. The combined effects of *Low gas prices* and *Expanded nuclear* show the largest changes in India (96% reduction) and Europe (83% reduction). These countries are followed by the FSU and Japan with 70% reductions to 8 and 4 EJ. The U.S. and China have the lowest percent changes in consumption with reductions of 60% to 17 and 31 EJ, respectively. The *Low gas prices* with in combination with *Expanded nuclear* actually stimulate economic activity in the U.S., raising coal consumption by roughly 20% compared to the *Low gas prices*, *Limited nuclear* scenario in the Low and *High* CO_2 *price* cases to 14 and 17 EJ, respectively. The U.S. is the only region in which higher nuclear output increases coal consumption.

3.3. Effects on coal prices

Accompanying these developments are changes in the price of coal, which the EPPA model treats as imperfectly substitutable among countries and thus available for use at somewhat different prices. Carbon prices and assumptions about natural gas prices and the growth of nuclear power affect these prices. The EPPA simulations, as shown in Table 7 indicate that this expanding use of coal will involve coal prices at or slightly above today's levels in the absence of CO_2 prices. Under *BAU* conditions, India exhibits the greatest change in coal prices with prices rising by 100%. China experiences price increases of 65–70% followed by the U.S., Japan, and FSU at

Table 7
Coal price index in 2050 under alternative assumptions, universal simultaneous participation (year 2000 = 1.0).

Scenario		Region	*BAU*	*Low* CO_2 *price*	*High* CO_2 *price*
Gas price	Nuclear				
EPPA-Ref	Limited	USA	1.47	1.21	1.17
		China	1.73	1.24	1.14
		India	2.15	1.53	1.34
		Europe	1.21	0.99	0.90
		FSU	1.43	1.03	0.97
		Japan	1.55	1.22	1.11
EPPA-Ref	Expanded	USA	1.39	1.14	1.08
		China	1.67	1.17	1.07
		India	2.01	1.37	1.22
		Europe	1.18	0.97	0.89
		FSU	1.41	1.02	0.97
		Japan	1.49	1.17	1.07
Low	Limited	USA	1.44	1.09	1.01
		China	1.71	1.15	1.07
		India	2.08	1.12	0.97
		Europe	1.20	1.02	0.88
		FSU	1.42	1.05	1.07
		Japan	1.53	1.18	1.04
Low	Expanded	USA	1.38	1.07	1.03
		China	1.64	1.08	1.01
		India	1.92	1.04	0.95
		Europe	1.18	1.00	0.88
		FSU	1.40	1.02	0.96
		Japan	1.48	1.13	1.02

40–50%. Europe's prices change by only 20%. Assumptions regarding gas prices and nuclear growth have minimal effects without a carbon policy.

With *Low* CO_2 *prices*, assumptions about gas price and nuclear growth have significant effects on coal prices. Instead of doubling, India's coal price ranges from no change to a 40% increase. China, the U.S. and Japan show 10–20% increases while the FSU and Europe show no change. Under *High* CO_2 *prices*, the price rise is tempered even further and can lead to price declines of 5–10% in the case of advanced nuclear and low gas prices. India has the widest range of prices, from 5% decrease to a 35% increase. Coal prices in the U.S. and China exhibit no change to a 15% increase. Changes in Japan and the FSU span from no change to a 10% increase. Prices in Europe drop roughly 10% in all cases.

4. The crucial role of capture and storage

A central conclusion to be drawn from our examination of alternative futures for coal is that, if CCS is successfully adopted, coal utilization will likely expand even with stabilization of CO_2 emissions. As shown below, extension of these emissions control scenarios farther into the future shows continuing growth in coal use provided CCS is available. Also to be emphasized is the fact that market adjustment to CCS requires a significant and widely applied charge for CO_2 emissions to incentivize adoption.

The extent of coal CCS adoption under all scenarios with *Low* CO_2 *prices* and *High* CO_2 *prices* is presented in Table 8. At *Low* CO_2 *prices*, coal CCS provides only 2% of global electricity supply by 2050. Of the regions examined here, China accounts for most of the coal CCS generation. China adopts CCS technology earlier than most regions because (1) its fleet of existing plants is less efficient than plants in other regions, (2) electricity demand is growing rapidly, and (3) substitution to natural gas is more difficult because China has low domestic gas reserves and gas imports are small relative to other imports. Of the regions considered in this study, the U.S. has invested in a few plants by 2050 as has the FSU under *Low gas prices*.

All of the regions, with the exception of Japan, adopt CCS under the *High* CO_2 *price* scenarios as depicted in Fig. 4. Again, China is the largest adopter of CCS technologies with 8–11 EJ per year of generation by 2050. Coal CCS provides 67–91% of China's electricity across the gas and nuclear scenarios. With *EPPA-Ref gas prices*, the U.S. is the second largest adopter of coal CCS with 6.6–9.4 EJ per year of generation. Coal CCS provides 30–44% of its electricity. India and the FSU, again under *EPPA-Ref gas prices*, are a distant third and fourth in generation at 1.5–1.8 and 0.9 EJ per year, respectively. Japan is slower to adopt coal CCS because of the high thermal efficiency of its conventional sector and the ease with which Japan can substitute natural gas for coal in the EPPA model (see footnote 8).

With *Low gas prices*, CCS adoption in the FSU increases slightly to 1.1 EJ per year as the FSU exports more gas and relies more heavily on coal for its own generation. U.S. coal CCS generation drops to 1–2 EJ per year as advanced gas technologies are favored over coal CCS. India follows a similar path. Europe shows minimal adoption across all of the cases (0.1–0.2 EJ per year). Europe and Japan switch to natural gas generation prior to 2050 more readily than other regions because they currently import significant quantities of natural gas.

The importance of CCS for this picture of future coal use is underlined by the projection of coal use if the same CO_2 emission penalty is imposed *and CCS is not available*, as shown in Table 9. This chart motivates our study's emphasis on coal use with CCS. The successful adoption of CCS is critical to future coal use in a carbon-constrained world. With *High* CO_2 *prices* and *without* CCS, global coal consumption rises to only 116 EJ by 2050, a reduction of nearly 30% from the same scenario *with* CCS. Regionally, the FSU experiences the greatest decline of almost 50% relative to consumption. Consumption in China and the U.S. declines by 38 and 30%, respectively from the case with CCS. Consumption remains at roughly year 2000 levels in these regions. India and Europe show only modest reductions in consumption of 5 and 7%.

More significantly, considering the energy needs of developing countries, this technology may be an essential component of any attempt to stabilize global emissions of CO_2, much less to meet the Climate Convention's goal of stabilized atmospheric concentrations. This conclusion holds even for plausible levels of expansion of nuclear power and also most likely for policies stimulating the other approaches to emissions mitigation such as renewables, demand response, and efficiency gains.

Note, however, that these simulation studies assume that CCS will be available, and proved socially and environmentally acceptable, at such time as more widespread agreement may be reached on direct penalties on CO_2 emissions. This technical option is not available in this sense today, of course. Many years of development and demonstration will be required to prepare for its successful, large-scale adoption throughout the world. A rushed attempt at CCS implementation could lead to project failure, economic waste and, at worst, loss of this important option even when there is societal willingness to pay for it. Therefore these simulation studies further suggest that development work is called for now at a scale appropriate to the technological and societal challenge in the search for the most effective and efficient path forward.

Table 8
Coal CCS Output, % Electricity from Coal, and % of Coal to CCS in 2050, universal simultaneous participation.

Scenario		Region	Coal CCS output (EJ)		% Electricity from coal CCS		% of Coal to CCS	
Gas price	Nuclear		Low price	High price	Low price	High price	Low price	High price
EPPA-Ref	Limited	Global	2.4	29.2	2%	26%	4%	60%
		USA	0.1	9.4	0%	44%	<1%	76%
		China	1.8	11	16%	91%	16%	88%
		India	0	1.8	0%	27%	0	33%
		Europe	0	0.1	0%	1%	0	7%
		FSU	0	0.9	0%	10%	0	48%
		Japan	0	0	0%	0%	0	0
EPPA-Ref	Expanded	Global	2.1	22.5	2%	19%	4%	62%
		USA	0.1	6.6	0%	30%	1%	86%
		China	1.6	8.4	14%	69%	18%	85%
		India	0	1.5	0%	21%	0	44%
		Europe	0	0.1	0%	1%	0	4%
		FSU	0	0.9	0%	10%	0	47%
		Japan	0	0	0%	0%	0	0
Low	Limited	Global	2.3	21.6	2%	19%	5%	65%
		USA	0.1	1.9	0%	9%	2%	46%
		China	1.7	11	14%	91%	38%	88%
		India	0	0.3	0%	4%	0	50%
		Europe	0	0.2	0%	1%	0	9%
		FSU	0.1	3.6	1%	41%	7%	78%
		Japan	0	0	0%	0%	0	0
Low	Expanded	Global	2.1	14.2	2%	12%	5%	52%
		USA	0.1	1.1	0%	5%	2%	22%
		China	1.5	8.2	13%	67%	36%	85%
		India	0	<0.1	0%	0%	0	12%
		Europe	0	0.1	0%	1%	0	8%
		FSU	0.1	1.1	1%	13%	8%	52%
		Japan	0	0	0%	0%	0	0

Table 9
Coal use with and without CCS, universal simultaneous participation, *EPPA-Ref gas prices* and *Limited nuclear* (EJ).

Region	*BAU*		*High* CO_2 *price* in 2050		
	2000	2050	With CCS	Without CCS	% Change
Global	100	447	161	116	−28
USA	24	58	40	28	−30
China	28	88	39	24	−38
India	7.3	41	22	21	−5
Europe	10	36	5.8	5.4	−7
FSU	7.1	30	7.1	3.7	−48
Japan	3.6	15	5.1	5.1	0

5. Extension to 2100

The application of this analysis in Ansolabehere et al. (2007) explored only to 2050. In Table 10 we extend the simulations to 2100 for a subset of the cases above, to explore coal prospects over the longer term. Prices of CO_2 are assumed to continue growth at the same rates as in Fig. 3: 5% for the Low case leading to $669 per t in 2100, and 4% for the high case which rises to $834 in 2100 (all still in 2005 dollars). In the *Expanded nuclear* case the contribution of this technology is assumed to rise by 3% per year in all regions from 2050 to 2100, whereas in the *Limited nuclear* case it remains at roughly the 2050 level. Only the *EPPA-Ref gas price* is explored in this extension to 2100 and in the U.S. it reaches around seven times the base year (2000) price by 2100 up from 3.6 times in 2050. Under *BAU* conditions global CO_2 emissions reach 92 $GtCO_2$ per year with coal's share of emissions rising slightly from 53% in 2050 to 55% in 2100.

Under the *Low* CO_2 *price* and *High* CO_2 *price* scenarios and *Limited nuclear*, global CO_2 emissions decline to 15 and 13 $GtCO_2$ per year, respectively. Due to the widespread adoption of CCS technologies, emissions from coal are roughly a tenth of their year 2000 levels while consumption has grown fourfold. Coal emissions account for less than 10% of total CO_2 emissions.

Table 11 shows regional coal use under *High* CO_2 *prices* and *Low* CO_2 *prices* as well as *Limited nuclear* and *Expanded nuclear*. Coal consumption under the Low and High carbon prices is nearly the same for most regions with the exception of FSU and Japan. In the FSU, coal consumption by the coal CCS technology peaks in 2065 and gradually loses market share to gas CCS technology thereafter. In Japan, the *High* CO_2 *price* scenario leads to earlier and faster adoption of coal CCS than in the *Low* CO_2 *price* case.

By 2100, the *Expanded nuclear* case paints a very different picture for coal. Global coal expansion is limited to between 120 and 160 EJ depending on the assumed CO_2 price trajectory.

Table 10
Global coal use at alternative CO_2 prices in 2050 and 2100, universal simultaneous participation, *EPPA-Ref gas prices* and *Limited nuclear*.

Indicator	*BAU*			*Low* CO_2 *price*		*High* CO_2 *price*	
	2000	2050	2100	2050	2100	2050	2100
Coal consumption (EJ per year)	100	448	734	200	438	161	385
Coal CO_2 emissions ($GtCO_2$ per year)	9	40	51	17	1	5	0.9
% Coal consumption by CCS	0%	0%	0%	4%	97%	60%	96%
% CO_2 emissions from coal	38%	57%	60%	38%	7%	19%	7%

Table 11
Coal use in 2100, universal simultaneous participation and *EPPA-Ref gas prices* (EJ).

Nuclear	Region	*BAU*		*Low* CO_2 *price*	*High* CO_2 *price*	Index 2100–2000		
		2000	2100	2100	2100	*BAU*	Low	High
Limited	Global	100	734	438	385	7.3	4.4	3.9
	USA	24	106	66	64	4.4	2.8	2.7
	China	28	110	55	53	3.9	2.0	1.9
	India	7.3	67	43	44	9.2	5.9	6.0
	Europe	10	50	39	39	5.0	3.9	3.9
	FSU	7.1	48	32	22	6.8	4.5	3.1
	Japan	3.6	21	11	16	5.8	3.1	4.4
Expanded	Global	99	571	161	123	5.8	1.6	1.2
	USA	23	75	0.5	0.6	3.3	0.0	0.0
	China	26	101	17	15	3.9	0.7	0.6
	India	7.2	46	7.6	6.8	6.4	1.1	0.9
	Europe	10	13	4.3	4.9	1.3	0.4	0.5
	FSU	7.1	38	15	9.2	5.4	2.1	1.3
	Japan	3.6	7.5	1.5	1.3	2.1	0.4	0.4

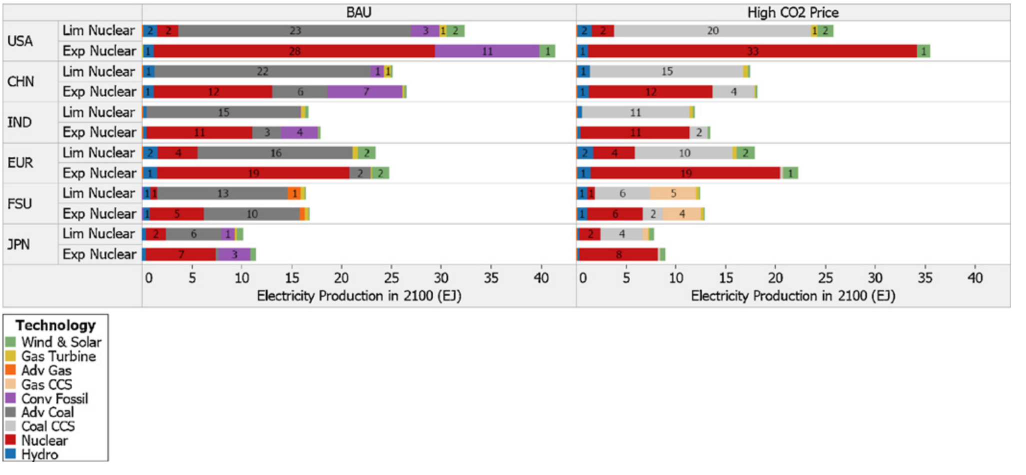

Fig. 6. Electricity production in 2100 under alternative policies with universal, simultaneous participation, *EPPA-Ref gas prices*, and limited and *Expanded nuclear* (EJ per year).

Coal consumption in the U.S. declines to less than 1 EJ per year. The only regions showing consumption at or above 2000 levels are India and the FSU. Fig. 6 shows the underlying electricity generation by technology that explains these consumption patterns. Naturally, all these results are dependent on the estimates of the relative cost per kW of nuclear and coal generation capacity with carbon capture.

6. Conclusions

Analysis of coal consumption under alternative assumptions about price penalties on CO_2 emissions shows that, even under greenhouse gas controls, the coal industry will likely be larger in 2050 than today if nuclear growth is restrained and natural gas prices follow the projection of our economic model. *Provided*, that is that CO_2 capture and storage (CCS) is available. If CCS development is for some reason restrained then projected 2050 coal use is substantially reduced. Growth in nuclear power also reduces coal use in the period to 2050, though not necessarily below levels of today if CCS is applied.

Looking farther in the future, coal would regain much of the early in-century growth lost to CO_2 mitigation, again assuming nuclear growth is restrained and investment continues in CCS technology. Even with strong nuclear expansion, a CCS-enabled coal industry is projected to be larger in 2100 than today.

The implementation of a dispatching algorithm that distinguishes peak, intermediate and base-load dispatch leads to differences in results for these competing technologies and is viewed as an improvement in the capability of the EPPA model. Subsequent stages in enhancement of this analysis facility, for analysis of the electric sector, will involve the explicit representation of advanced nuclear power designs, for a more accurate modeling of the competition between coal with CCS and nuclear and advanced gas technology.

Acknowledgements

We thank Piyush Hari for his research assistance, and three anonymous referees and ZhongXiang Zhang for their comments. The EPPA model used here is supported by the U.S. Department of Energy, U.S. Environmental Protection Agency, U.S. National Science Foundation, U.S. National Aeronautics and Space Administration, U.S. National Oceanographic and Atmospheric Administration and the Industry and Foundation Sponsors of the MIT Joint Program on the Science and Policy of Global Change.

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