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Analysis of the Coal Sector under Carbon Constraints

James R. McFarland, Sergey Paltsev and Henry D. Jacoby

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Abstract

Application of the MIT Emissions Prediction and Policy Analysis (EPPA) model to assessment of the future of coal under climate policy revealed the need for an improved representation of load dispatch in the representation of the electric sector. A new dispatching algorithm is described and the revised model is applied to an analysis of the future of coal use to 2050 and 2100 under alternative assumptions about CO_2 prices, nuclear expansion and prices of natural gas. Particular attention is devoted to the potential role of coal-electric generation with CO_2 capture and storage. An appendix provides a comparison of a subset of these results with and without the more detailed model of electric dispatch.

Contents

1. INTRODUCTION

As an input to the MIT study of *The Future of Coal* (Ansolabehere *et al*., 2007) the MIT Emissions Projection 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

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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.

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 Section 5 and Section 6 concludes. The effects of the different formulations on projected energy use, CO_2 emissions, and CCS use are explored in the Appendix.

2. THE MIT EPPA MODEL

2.1 Model Structure

In this analysis we apply the Emissions Prediction and Policy Analysis (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 and 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 sixteen countries or aggregate regions, six non-energy sectors, fifteen energy extraction and conversion sectors and specific technologies, and includes a representation of household consumption behavior, as presented in **Table 1**. The model is solved on a five-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 carbon capture and storage (CCS).

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, 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.

Table 1. Regions and Sectors in the EPPA4 Model.

Country / Region	Sectors
Annex B	**Non-Energy**
United States (USA)	Agriculture (AGRI)
Canada (CAN)	Services (SERV)
Japan (JPN)	Energy Intensive products (EINT)
European Union+[a] (EUR)	Other Industries products (OTHR)
Australia/New Zealand (ANZ)	Industrial Transportation (TRAN)
Former Soviet Union (FSU)	Household Transportation (HTRN)
Eastern Europe[b] (EET)	**Energy**
Non-Annex B	Coal (COAL)
India (IND)	Crude Oil (OIL)
China (CHN)	Refined Oil (ROIL)
Indonesia (IDZ)	Natural Gas (GAS)
Higher Income East Asia[c] (ASI)	Electric: Fossil (ELEC)
Mexico (MEX)	Electric: Hydro (HYDR)
Central and South America (LAM)	Electric: Nuclear (NUCL)
Middle East (MES)	**Advanced Energy Technologies**
Africa (AFR)	Electric: Simple Cycle Gas Turbine (GT)
Rest of World[d] (ROW)	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, Phillipines, Singapore, Taiwan, Thailand
[d]All countries not included elsewhere: Turkey, and mostly Asian countries.

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.

- The production structure of electricity from new dispatchable technologies is modified to include base load, intermediate load, and peak load generation,

- New fossil-based electricity generating technologies, such as supercritical pulverized coal and simple cycle gas turbine, are introduced, and
- The bottom-up economic data of all new fossil generating technologies are updated.

These modifications are discussed in detail below.

Electricity demand varies over hours, days and months due to high demand periods during the day and low at night, the workweek vs. weekend, and seasonal light and temperature differences. These intra-annual 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 we introduce base load, intermediate load and peak load to the production structure for electricity from new dispatchable generation technologies.[1] The combined supply from these different service levels is modeled as a perfect substitute for electricity generated using extant (conventional) technologies which are not distinguished by position on the load curve. The sector structure is shown in **Figure 1** which details the factor inputs to these generation sources.[2]

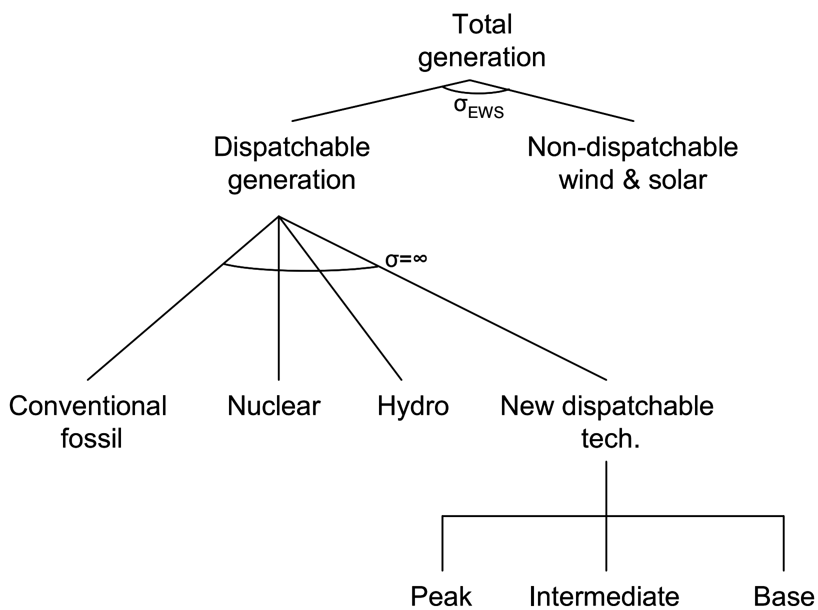

Figure 1. Nesting structure of dispatchable electricity in EPPA.

The electric output for each load category may be supplied by one or more technologies as shown in **Figure 2**. For each of these dispatchable technologies there is a further nesting of inputs as detailed in Panel d of Figure 6 in Paltsev *et al.* (2005). 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 carbon capture

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[1] 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.

[2] The growth of nuclear power is assumed here to be largely exogenous (see Table 4).

and storage. The advanced gas technology is modeled after a natural gas combined cycle plant (see McFarland *et al.*, 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.[3]

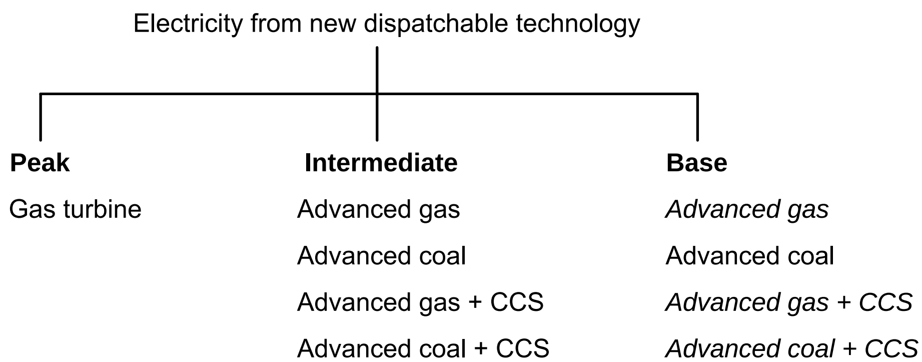

Figure 2. Technology options for peak, intermediate and base load generation (technologies added in EPPA version 4 in italics).

Intra-annual demand variation for the extant technologies (conventional fossil, nuclear, and hydro) is already accounted for in the base-year data. Non-dispatchable generation (*e.g.*, wind and solar), by definition, is not load following and is treated as an imperfect substitute for dispatchable generation (see Paltsev *et al.*, 2005). As the simulation proceeds, older vintages of conventional generation (without the dispatching detail) are retired from use, and because of their improved characteristics the electric service progressively shifts to the new dispatchable sources.

To estimate the share of electricity assigned to each load category, we use the annual distribution of demand for the U.S. as shown in the load duration curve in **Figure 3**, plotted from highest load to lowest load (Hadley and 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 hours per year (3.3 hours per day) out of the total 8760 hours 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 Figure 3). Intermediate load is defined as the MW output in the top 5000 hours per year (10.4 hours 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

[3] 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.

generation required to produce a perfect substitute for generation from the extant technologies are based upon the revenue stream of each category of generation, 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 shut-down costs are incurred. We derive the value share for each category by running the Oak Ridge National Laboratory's ORCED model (Hadley and Hirst, 1998) for the U.S. The shares of revenue by load category are 3% peak, 14% intermediate, and 83% base. 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.

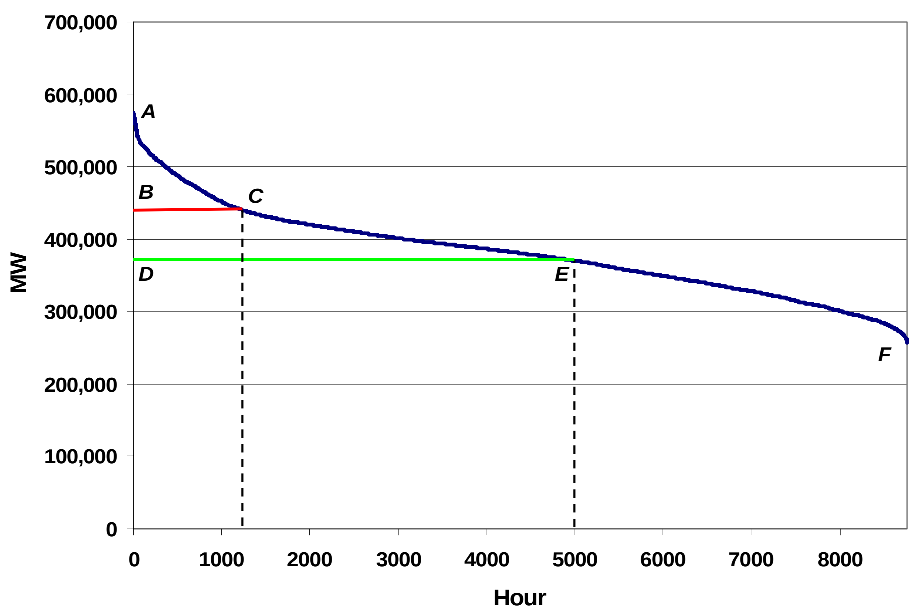

Figure 3. Annual load duration curve for the U.S.

The Appendix explores the implications of alternative patterns of this load-duration relationship. There it is shown that the introduction of load dispatching has a significant effect on several important model outputs when compared to the same model without load segments for peak and intermediate load. Different levels of peaking demand are explored under a "High CO_2 price" scenario as described below. With load dispatch coal consumption declines by 5% to 11% in 2050 without a carbon policy (Business-As-Usual or *BAU*) but rises by 1% to 2% with a sample emissions control policy. Global CO_2 emissions decline by 3% to 5% without policy and by 4% to 8% with a policy. This difference in emission reduction and coal consumption suggests that CCS plays a more prominent role when electricity dispatch is modeled explicitly. Globally, generation from coal with CCS rises by 9% to 20% with load dispatch while total electricity demand falls by 3% to 9% in the no-policy cases and between 2% and 4% under the high CO_2 prices.

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; U.S. DOE, 2004; U.S. EPA, 2005). The capacity factors for peak (13%), 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 coal and gas are assumed to be $1.44/MMBtu and $5.00/MMBtu respectively. We assume a cost of 2.43 cents/kWh for electricity transmission and distribution and \$10/tCO_2 for the cost of CO_2 transport and storage (McFarland *et al.*, 2004).

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	Shoulder	Base	Shoulder	Base
Capacity Factor	14%	54%	85%	54%	85%
Capital ($/kW)	460	510	510	1330	1330
Heat Rate (Btu/kWh)	8550	6138	6138	8709	8709
Cost of Electricity (cents/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. & Dis.	2.40	2.40	2.40	2.40	2.40
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.

The cost of electricity for each type of generation 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 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. 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 fixed factor that grows endogenously based on the previous period's output, as described by Paltsev *et al.* (2005).

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	Shoulder	Base	Shoulder	Base
Capacity Factor	54%	85%	54%	85%
Capital	1084	1084	1893	1893
Heat Rate	6991	6991	10223	10223
Cost of Electricity (cents/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. & Dis.	2.40	2.40	2.40	2.40
CO_2 Trans. & 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.

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. The two policy cases, "*Low CO_2 price*" and "*High CO_2 price*", are shown in **Figure 4**, with the CO_2 penalty stated in terms of 2005 $US per ton 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 in 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 ton 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 ton CO_2 in the year 2015 with a rate of increase of 4% thereafter.[4] 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.

[4] 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.

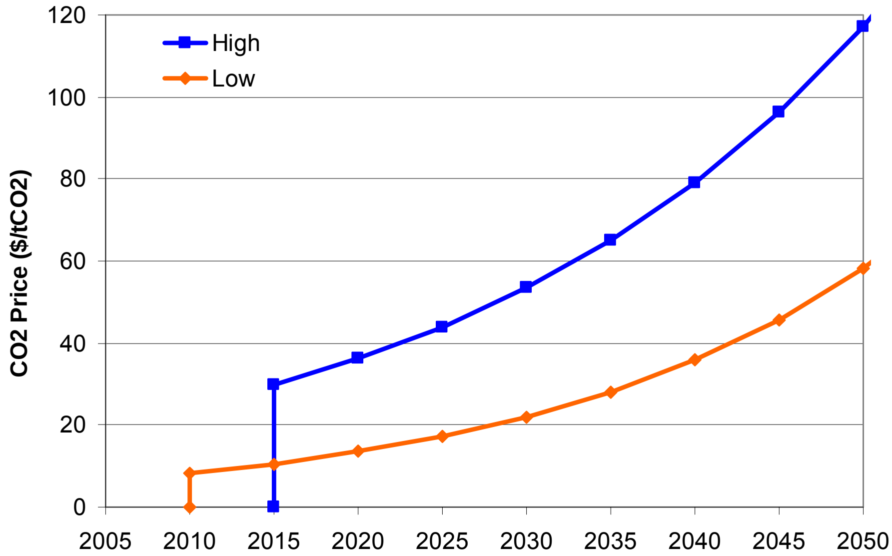

Figure 4. Scenarios of Penalties on CO_2 Emissions ($/t CO_2).

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.

Table 4. Alternative Cases for Nuclear Generation (Million GWh/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 & 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).

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 "*Business-as-usual*" 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 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/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 Figure 4. 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 **Figure 5** on the assumption of "*Limited nuclear*" generation, and "*EPPA-Ref gas prices*". 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.

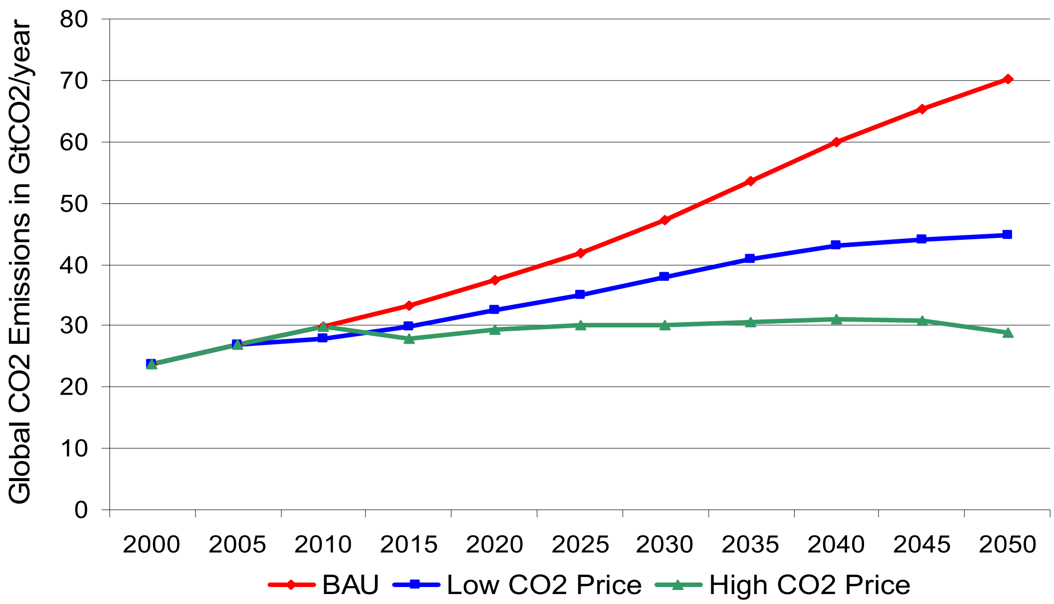

Figure 5. Global CO_2 emissions under alternative policies with universal, simultaneous participation, "*Limited nuclear*" and "*EPPA-Ref gas prices*" ($GtCO_2$/year).

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 $GtCO_2$ per year 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 carbon capture and storage (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.

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/yr)	100	448	200	161
Coal CO_2 emissions ($GtCO_2$/yr)	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*".

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% to 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[5]. China and the U.S. accounted for over 50% of global consumption in 2000 at 28 EJ and 24 EJ respectively. Europe, India, and the FSU each accounted for between 7 to 10 EJ of coal consumption while Japan consumes 3.6% of the total. Under the "*Business-as-usual*" case with "*EPPA-Ref gas prices*" and "*Limited nuclear*", coal consumption in China rises by a factor of three to 88 EJ in 2050 while U.S. consumption grows by 140% to 58 EJ. Consumption in India, the EU and FSU grows to between 30 and 40 EJ with the fastest growth occurring in India (460%).[6] Japan's consumption quadruples to 15 EJ over this time.

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

Scenario		**Region**	**BAU**		**Low CO_2 Price**	**High CO_2 Price**	**Index 2050 to 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

[5] 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.

[6] 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.

Similarly, there is strong regional variation the Table 5 results for the effects of carbon policy which can be seen in the top panel for "*EPPA-Ref gas prices*" and "*Limited nuclear*" scenario. Under "*Low CO_2 price*s", the coal consumption in the FSU exhibits the greatest decline, 84%, to 5 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 FSU's 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.

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 "*Business-as-usual*" 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.[7]

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 EJ 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%

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

under both price paths to 30 EJ. Similarly, nuclear expansion with low CO_2 prices in the EU and Japan lowers coal use by roughly 20%, yet with high CO_2 prices consumption drops by only 7-10%. 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.

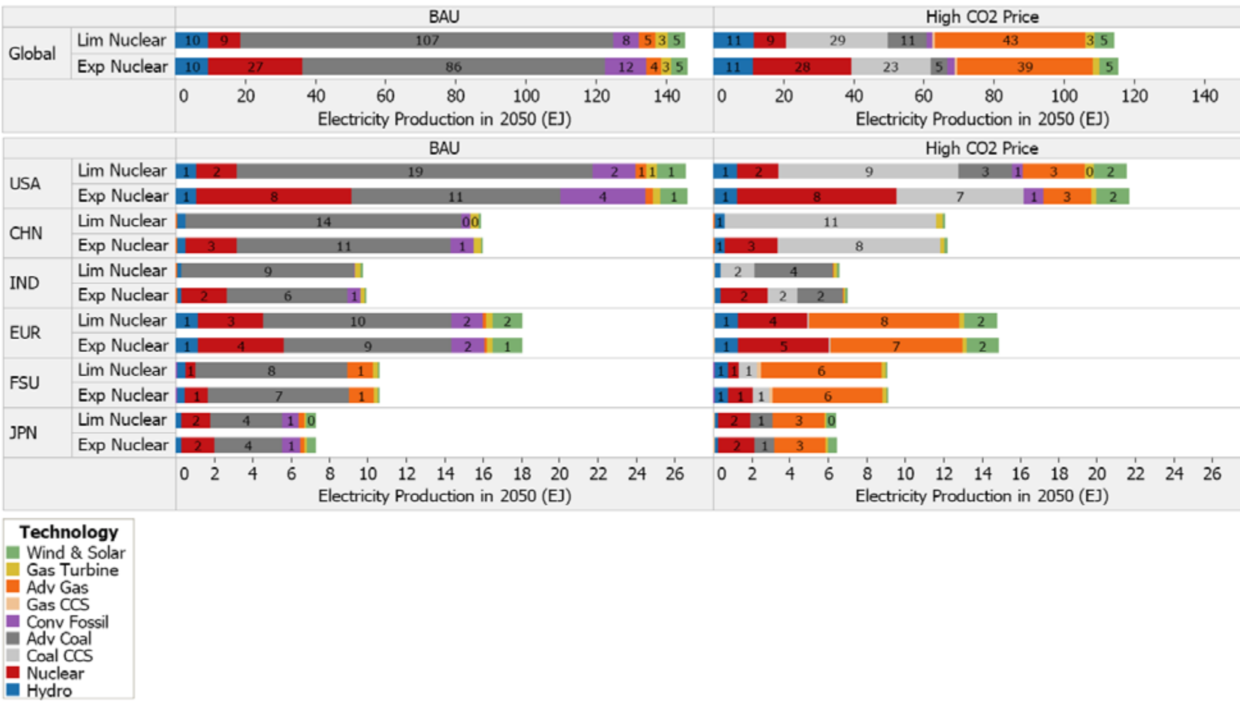

Figure 6. Electricity Production in 2050 Under Alternative Policies with Universal, Simultaneous Participation, "*EPPA-Ref gas prices*", "*Limited nuclear*" and "*Expanded nuclear*" (EJ/year).

Figure 6 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 Figure 6 is the fact that conventional fossil generation (*i.e.* that existing in 2000) has been retired and only 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 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.[8] These factors make natural gas generation more competitive with coal CCS in these two than in other regions.

[8] 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.

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 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 EJ 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 EJ and 4 EJ. The U.S. and China have the lowest percent changes in consumption with reductions of 60% to 17 EJ 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 EJ 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% to 70% followed by the U.S., Japan, and FSU at 40% to 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% to 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 to 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 carbon capture and storage 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.

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

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 at by 2050 as has the FSU under "*Low gas prices*".

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

All of the regions, with the exception of Japan, adopt CCS under the "*High CO_2 price*" scenarios as depicted in Figure 4. Again, China is the largest adopter of CCS technologies with 8 to 11 EJ per year of generation by 2050. Coal CCS provides 67% to 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 to 9.4 EJ per year of generation. Coal CCS provides 30% to 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 EJ per year 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 to 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%.

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

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.

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 Figure 4: 5% for the Low case leading to $669 per ton 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% from 2050 to 55% in 2100.

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/yr)	100	448	734	200	438	161	385
Coal CO_2 emissions ($GtCO_2$/yr)	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%

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 four-fold. 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.

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 to 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

By 2100, the "*Expanded nuclear*" case paints a very different picture for coal. Global coal expansion is limited to between 120 to 160 EJ depending on the assumed CO_2 price trajectory. 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. **Figure 7** 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.

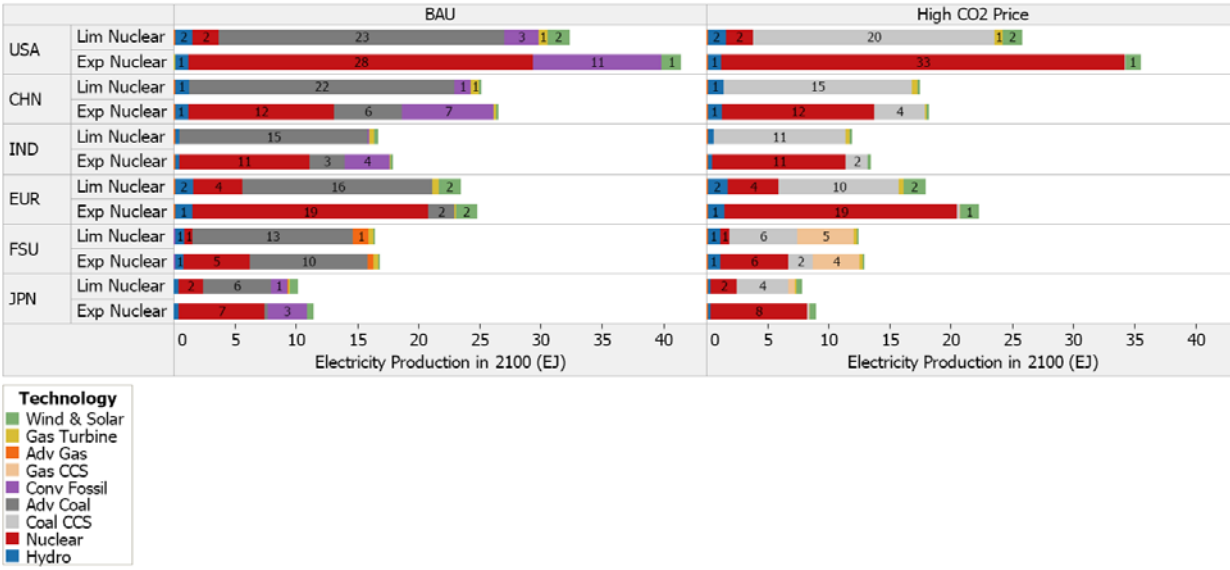

Figure 7. Electricity Production in 2100 Under Alternative Policies with Universal, Simultaneous Participation, EPPA-Ref gas Prices, and Limited and Expanded nuclear (EJ/year).

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.

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APPENDIX: COMPARISON OF ELECTRIC SECTOR MODELS

This section examines the effects of separating electricity generation into peak, intermediate, and base loads, and tests the model's sensitivity to the share of revenue provided by each load segment. More detailed modeling of electric dispatch allows us to focus more on specific technologies, but as peaking and intermediate loads require relatively more expensive and carbon-intensive generation, this disaggregation may also affect total CO_2 emissions and cost of electricity.

To examine the implications of the addition of the new dispatch procedure, and to test the sensitivity results to load shape, three cases are examined:

- The standard EPPA (NoPIB),
- EPPA with peak, intermediate, and base using respective revenue share of 3%, 14%, and 83% (PIB), and
- EPPA with higher peaking and intermediate demands (PIB High Peak, denoted PIB HP) constituting revenue shares of 10%, 30%, and 60%.[9]

This third case would reflect a system with higher peak loads because of, for example, strong air conditioning load in summer months or perhaps less storage capability such as pumped hydro power which allows the use of base load energy to meet peak demands.

The effects of these conditions on coal consumption, total CO_2 emissions, CO_2 emissions from coal, total electricity generated, electricity from coal with CCS, electricity prices, and coal prices are presented in **Tables A1 - A7**. The cases are for "*EPPA-Ref gas prices*" and "*Limited nuclear*" as defined in Section 3 of the paper. Both the absolute value and the percentage change from the standard model (NoPIB) in 2050 and 2100 are reported. The analysis focuses on the relative changes in results from the standard model. As noted in the analysis above, the 2050 results reflect a transition period for technologies, especially coal CCS. Results for 2100 are reported to illustrate long-term equilibrium outcomes. The underlying assumptions for the extension to 2100 are those in Section 5. For this analysis, we examine both *"BAU"* and "*High CO_2 price*" scenarios.

As shown by this sensitivity analysis, more detailed modeling of electric dispatch does not substantially affect global emissions profiles. Even under the most extreme case (10% of peaking and 30% of intermediate load), global CO_2 emissions differ by only 7% from their reference emissions by 2100 (a difference that is far lower than reasonable uncertainty in the reference electric emissions). Estimated emissions and policy cost between these two dispatch models can vary more substantially by individual country or region, however. In these applications the same load profile is applied across all regions and all time periods. The variation in regional results in these experiments thus suggests the value of further research on electric demand in an effort tailor the load profile to the economic structure and behavior of individual regions and over time.

[9] These revenue shares were estimated from the Pennsylvania-New Jersey-Maryland electric reliability area of North America based on 2005 locational marginal price data. Peak revenue is calculated from the top 1200 hours in the year. Intermediate revenue is determined from the next 5000 hours with base comprising the rest.

A1. Coal Consumption

Under the *"BAU"* policy in 2050, the addition of the PIB structure lowers global coal consumption by 5% to 11%. Regional changes range from +6% (China, India) to -20 to -40% (Europe, FSU, Japan). By 2100 the global effect is less pronounced with reductions of 2% to 6%. Regional changes range from +5% to -20%. With load dispatch, electricity generally becomes more expensive than without because a greater amount of capital, and to a lesser extent, high value natural gas is used for peaking and intermediate generation. This raises electricity prices (see Table A6a) and lowers total electricity consumption (see Table A4a). Regions with higher coal consumption (China, India, in 2050 and 2100 and in the U.S. in 2100) show shifts of coal consumption from the electric power sector to other sectors such as energy intensive industries.

Under "*High CO_2 prices*" in 2050, the addition of load dispatch leads to a modest 1% to 2% increase in global coal use, as shown in the far right columns of the table. However, large regional differences exist. Most of the regions examined experience declines of 7% to 51% while coal consumption increases in the U.S. and FSU by 14% to 23%. Declines in most regions are explained by the same supply and demand story as in the *"BAU"* case. The addition of load dispatching raises the price of electricity and carbon prices penalize coal generation more than other forms thus coal demand declines.

The U.S. and FSU are anomalies to this.[10] In the U.S., with load dispatch, the coal capture technology enters more rapidly. Because a higher share of gas is required with load dispatch, the equilibrium price of electricity becomes high enough to make coal with CCS more economically attractive than in the NoPIB case. In the FSU, without load dispatch, the advanced natural gas technology predominates electricity generation from 2050 through 2100. The addition of load dispatch raises the equilibrium electricity price which lessens the difference between the natural gas technology and the coal capture technology and raises coal consumption by 23% to 80%. By 2100 all regions except the FSU show declines in coal consumption of 0% to 35% owing to the higher prices brought on by load dispatch.

[10] Japan and India also show interesting behavior. In Japan in 2050, the PIB case increases coal consumption by 18% while the PIB-HP case reduces coal consumption by 27%. The switch from noPIB to PIB increases coal consumption by making the advanced coal technology without capture more competitive with gas. However, in the PIB-HP case, higher electricity prices allow the coal capture technology to compete more favorably with advanced natural gas. The slower penetration rate of this technology reduces coal consumption. A similar story holds for India although the change in coal consumption is smaller.

Table A1. Coal consumption under different dispatch models (EJ).*

A1a. Results to 2050.

Region	BAU				High CO_2 Price			% Change from NoPIB: BAU		% Change from NoPIB: High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
Global	100	470	448	418	158	161	159	-5%	-11%	2%	1%
USA	23.6	63.9	58.4	54.1	39.6	40.3	45.3	-9%	-15%	2%	14%
China	26.5	86.9	87.9	91.1	42.0	39.3	37.1	1%	5%	-6%	-12%
India	7.3	42.1	41.0	44.8	21.3	22.1	19.8	-3%	6%	4%	-7%
Europe	10.4	38.9	36.0	30.9	6.0	5.8	2.9	-7%	-21%	-4%	-51%
FSU	7.1	33.2	29.9	22.8	5.8	7.1	7.1	-10%	-31%	23%	23%
Japan	3.6	16.2	15.0	9.1	4.3	5.1	3.1	-8%	-44%	18%	-27%

* Universal, simultaneous participation, "*Limited nuclear*" and "*EPPA-Ref gas prices*".

A1b. Results to 2100.

Region	BAU				High CO_2 Price			% Change from NoPIB: BAU		% Change from NoPIB: High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
Global	100	752	734	707	410	385	337	-2%	-6%	-6%	-18%
USA	23.6	105	106	107	70.9	64.5	56.7	1%	1%	-9%	-20%
China	26.5	108	110	114	60.5	53.4	39.6	2%	5%	-12%	-35%
India	7.3	68.8	67.3	67.9	48.5	43.6	36.3	-2%	-1%	-10%	-25%
Europe	10.4	51.2	50.3	41.4	39.0	39.1	30.4	-2%	-19%	0%	-22%
FSU	7.1	53.6	47.7	45.7	18.0	22.3	32.1	-11%	-15%	24%	79%
Japan	3.6	22.8	21.1	18.3	18.5	16.3	13.6	-8%	-20%	-12%	-26%

* Universal, simultaneous participation, "*Limited nuclear*" and "*EPPA-Ref gas prices*".

A2. CO_2 Emissions

Global annual carbon dioxide emissions with PIB and PIB-HP under a *"BAU"* policy in 2050 are 3% to 7% lower than the NoPIB case as presented in Table A2a. Regional reductions range from 1% (China) to 15% (FSU, Japan). The results are similar globally and regionally out to 2100. The electricity price is higher with load dispatch because of the higher share of natural gas in the generating technology bundle. This leads to a substitution away from electricity and a reduction in CO_2 emissions.

With "*High CO_2 prices*", the incorporation of load dispatch reduces global emission in 2050 by 4% to 8%. Regionally, the reductions range from 0% to 27% depending on the extent of CCS adoption. China's emissions rise by 5% in the PIB-HP case because the share of coal use in non-electric sectors rises from 11% in the NoPIB case to 22% in the PIB-HP case.

However, by 2100 annual emissions are 2% to 8% higher globally and 1% to 15% higher on a regional basis. Although higher electricity prices with PIB and PIB-HP allow earlier entry of CCS technologies before 2050, the higher long-run electricity prices lowers the share of CCS generation, and thus raise emissions.

Table A2. CO_2 emissions under different dispatch models ($GtCO_2$).*

A2a. Results to 2050.

Region	**BAU**				**High CO_2 Price**			**% Change from No PIB**			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	NoPIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
Global	23.8	72.5	70.3	67.3	29.9	28.8	27.4	-3%	-7%	-4%	-8%
USA	6.0	12.5	12.0	11.7	6.5	6.1	5.4	-4%	-6%	-6%	-17%
China	3.1	9.9	9.7	9.5	1.8	1.8	1.9	-1%	-4%	0%	5%
India	1.0	4.3	4.0	4.1	1.9	1.7	1.4	-6%	-3%	-11%	-27%
Europe	3.6	7.8	7.6	7.2	4.1	3.8	3.8	-3%	-8%	-7%	-7%
FSU	2.1	5.4	5.2	4.7	2.4	2.3	2.3	-4%	-13%	-2%	-3%
Japan	1.2	2.9	2.8	2.5	1.8	1.8	1.7	-3%	-15%	-1%	-6%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A2b. Results to 2100.

	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
Global	23.8	106	103	98.9	12.6	13.0	13.7	-3%	-7%	2%	8%
USA	6.0	17.9	17.8	17.6	2.7	2.8	2.9	-1%	-1%	1%	5%
China	3.1	11.0	10.9	10.5	1.1	1.1	1.2	-1%	-5%	5%	13%
India	1.0	6.9	6.5	6.0	0.7	0.7	0.8	-6%	-13%	1%	15%
Europe	3.6	10.2	10.0	9.4	2.0	2.0	2.1	-2%	-8%	1%	5%
FSU	2.1	9.1	8.7	8.4	0.9	1.0	1.0	-5%	-7%	3%	9%
Japan	1.2	4.1	4.0	3.7	0.6	0.6	0.7	-3%	-8%	3%	10%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A3. CO_2 Emissions from Coal

CO_2 emissions from coal are lower across the board under the PIB and PIB-HP cases as compared to the NoPIB case (Table A3). The higher price of electricity causes a substitution away from electricity and therefore coal. Globally, CO_2 emissions from coal are lowered by 5 to 15% in the *"BAU"* case for 2050 and 2100.

With load dispatch, the High CO_2 price case exhibits dramatic reductions in coal emissions in 2050. Global coal emissions are reduced by 16% to 35% with regional reductions of up to 85% (USA) relative to the NoPIB case. By 2100, the global reduction is 4% to 5% with regional reductions of up to 28% (USA). India exhibits a 100% increase in emissions from coal in 2100 under the PIB-HP case. The absolute emissions from coal are quite low. The percentage change is high because India switches to the coal capture technology for intermediate load in this scenario.

Table A3. Coal emissions under different dispatch models ($GtCO_2$).*

A3a. Results to 2050.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
Global	9.0	42.4	39.9	36.1	6.4	5.4	4.2	-6%	-15%	-16%	-35%
USA	2.1	5.8	5.3	4.9	1.3	1.0	0.2	-9%	-15%	-28%	-85%
China	2.4	7.9	7.7	7.3	0.5	0.5	0.5	-3%	-7%	-5%	-3%
India	0.7	3.8	3.5	3.6	1.5	1.2	0.9	-7%	-5%	-14%	-35%
Europe	0.9	3.5	3.3	2.8	0.5	0.2	0.2	-7%	-21%	-69%	-69%
FSU	0.6	3.0	2.7	2.1	0.3	0.3	0.2	-10%	-31%	-1%	-1%
Japan	9.0	42.4	39.9	36.1	6.4	5.4	4.2	-6%	-15%	-16%	-35%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A3b. Results to 2100.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
Global	9.0	64.9	61.8	56.7	0.91	0.86	0.87	-5%	-13%	-5%	-4%
USA	2.1	8.3	8.1	7.8	0.07	0.06	0.05	-2%	-6%	-12%	-28%
China	2.4	9.4	9.2	8.6	0.13	0.12	0.11	-2%	-9%	-6%	-15%
India	0.7	5.8	5.3	4.8	0.05	0.05	0.10	-8%	-18%	-12%	100%
Europe	0.9	4.6	4.6	3.7	0.08	0.07	0.07	-2%	-19%	-7%	-15%
FSU	0.6	4.9	4.3	4.1	0.12	0.12	0.12	-11%	-15%	-1%	-1%
Japan	0.3	2.1	1.9	1.7	0.03	0.03	0.03	-8%	-20%	-5%	-11%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A4. Electricity Generation

Global electricity generation is lower with load dispatch under the *"BAU"* case in 2050 and 2100 by 3% to 9% with regional reductions of up to 15%. Under the "*High CO_2 price*" case, global generation falls between 2% and 4% in 2050 and 4% and 13% in 2100. Regional reductions are the greatest in China and India at 22% in 2100. The reduction in electricity demand is consistent with the higher electricity prices in the PIB and PIB-HP cases (see Table A6).

The USA, however, shows a slight increase in generation in 2050 under the "*High CO_2 price*", PIB-HP case. As stated earlier, high electricity prices in the USA allow the coal CCS technology to enter the market earlier and expand more rapidly. This leads to lower electricity prices and higher consumption from 2040 to 2050 in the US.

Table A4. Electricity generation under different dispatch models (EJ).*

A4a. Results to 2050.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
Global	45.5	150	145	137	116	114	111	-3%	-9%	-2%	-4%
USA	12.3	27.4	26.5	25.2	21.6	21.5	22.1	-3%	-8%	0%	2%
China	3.7	16.6	15.9	14.8	12.5	12.1	11.1	-4%	-11%	-3%	-11%
India	1.6	10.3	9.7	8.9	6.7	6.6	6.2	-6%	-14%	-3%	-9%
Europe	8.5	18.5	18.0	17.2	15.0	14.8	14.5	-3%	-7%	-2%	-3%
FSU	3.3	10.8	10.6	10.1	9.1	9.0	8.8	-2%	-6%	-1%	-3%
Japan	3.3	7.5	7.2	7.0	6.5	6.4	6.3	-3%	-6%	-2%	-4%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A4b. Results to 2100.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
Global	45.5	229	223	210	171	164	149	-3%	-8%	-4%	-13%
USA	12.3	33.2	32.3	30.6	26.9	25.8	23.5	-3%	-8%	-4%	-12%
China	3.7	26.0	25.1	23.3	18.7	17.4	14.5	-4%	-10%	-7%	-22%
India	1.6	17.6	16.6	15.0	13.0	11.9	10.1	-6%	-15%	-8%	-22%
Europe	8.5	24.1	23.4	22.2	18.4	17.9	17.0	-3%	-8%	-3%	-7%
FSU	3.3	16.8	16.4	15.5	12.9	12.4	11.3	-3%	-8%	-4%	-12%
Japan	3.3	10.3	10.0	9.6	8.0	7.8	7.5	-2%	-6%	-2%	-6%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A5. Coal CCS Generation

In 2050 under a "*High CO_2 price*" case, the total coal CCS generation tends to be higher with PIB or PIB-HP than in the standard version (Table A5). This is because higher electricity prices cause the CCS technology to enter earlier and significantly faster in most regions. The level of coal CCS generation expands globally by 9% to 20% with regional changes of 9% to 112%. Coal CCS is still gaining market share globally and in the U.S. in 2050. However, in China, the coal CCS technology becomes economically competitive in 2015 under NoPIB, PIB and PIB-HP. By 2050 it has saturated China's electricity market. Since PIB and PIB-HP lead to higher prices and greater gas consumption, the CCS coal share declines.

In 2100 with "*High CO_2 prices*", total coal CCS generation falls by 7 to 19% with regional reductions of up to 32%. The incorporation of load dispatch into the model raises the price of electricity and lowers overall electricity demand and therefore generation from coal CCS plants. The FSU is an exception to this. The incorporation of load dispatch raises the price of natural gas causing the FSU to switch from advanced gas generation with capture to coal capture.

Table A5. Coal CCS Generation under "*High CO_2 Prices*" in 2050 (EJ).*

A5a. Results to 2050.

Region	Coal CCS generation (EJ)			Share of Electricity from Coal CCS			% Change from NoPIB	
	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP
Global	26.7	29.2	32.0	23%	26%	29%	9%	20%
USA	7.8	9.4	12.7	36%	44%	58%	20%	63%
China	11.8	11.0	9.4	95%	91%	84%	-7%	-21%
India	1.3	1.8	2.1	19%	27%	34%	39%	63%
Europe	0.06	0.11	0.12	0%	1%	1%	96%	112%
FSU	0.55	0.93	0.93	6%	10%	11%	69%	70%
Japan	26.7	29.2	32.0	23%	26%	29%	9%	20%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A5b. Results to 2100.

Region	Coal CCS generation (EJ)			Share of Electricity from Coal CCS			% Change from NoPIB	
	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP
Global	110	103	89.6	64%	63%	60%	-7%	-19%
USA	21.6	19.8	16.2	80%	77%	69%	-8%	-25%
China	17.2	15.4	11.6	92%	89%	80%	-10%	-32%
India	12.3	10.9	8.4	95%	91%	83%	-12%	-32%
Europe	10.7	9.8	8.2	59%	55%	48%	-8%	-23%
FSU	4.3	5.6	8.2	33%	45%	72%	30%	91%
Japan	5.0	4.2	3.6	62%	54%	47%	-15%	-28%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A6. Electricity Prices

As previously mentioned, the addition of load dispatch to the model uniformly raises electricity prices in all regions in 2050 and 2100 by 3% to 24%. With "*High CO_2 prices*", load dispatch raises electricity prices by 1% to 22% in 2050 and by 4% to 51% in 2100. Electricity price in the USA in 2050 presents the sole exception as it declines by 5%. The electricity prices generated in the USA prior to 2050 leads to a rapid adoption of CCS technology. Electricity prices rise rapidly, peaking prior to 2050, then fall around 2050 and recover before 2100.

Table A6. Electricity price indices under different dispatch models in 2050 and 2100.*

A6a. Results to 2050.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
USA	1.0	1.46	1.54	1.68	2.18	2.18	2.06	5%	15%	0%	-5%
China	1.0	1.28	1.38	1.56	1.81	1.92	2.20	8%	21%	6%	22%
India	1.0	1.12	1.22	1.39	2.03	2.06	2.18	9%	24%	1%	7%
Europe	1.0	1.43	1.50	1.62	1.94	2.00	2.07	5%	14%	3%	6%
FSU	1.0	1.09	1.12	1.20	1.54	1.55	1.61	3%	11%	1%	5%
Japan	1.0	1.43	1.50	1.60	1.76	1.82	1.89	5%	12%	3%	7%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A6b. Results to 2100.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
USA	1.0	1.59	1.66	1.80	1.82	1.95	2.26	4%	13%	7%	24%
China	1.0	1.42	1.50	1.68	1.81	2.03	2.74	6%	18%	12%	51%
India	1.0	1.37	1.48	1.67	1.59	1.77	2.26	7%	21%	11%	42%
Europe	1.0	1.43	1.50	1.62	1.67	1.75	1.91	5%	13%	5%	15%
FSU	1.0	1.20	1.24	1.35	1.19	1.28	1.50	4%	12%	8%	26%
Japan	1.0	1.43	1.48	1.57	1.64	1.72	1.84	3%	10%	4%	12%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A7. Coal Prices

Under *"BAU"* conditions in 2050, load dispatch has a moderate effect on coal prices. Across all of the regions examined the PIB and PIB-HP change coal price by +1% (India) to -9%. In 2100, coal prices fall by 4% to 9%.

The prices changes under the "*High CO_2 price*" case are much smaller in 2050 with a range of +2% (FSU) to -3%. By 2100, the coal prices have fallen by 2% to 14% (China and India), with a slight increase in the FSU.

Table A7. Coal price indices under different dispatch models in 2050 and 2100.*

A7a. Results to 2050.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
USA	1.00	1.50	1.47	1.42	1.16	1.17	1.16	-2%	-6%	0%	0%
China	1.00	1.76	1.73	1.70	1.15	1.14	1.12	-2%	-3%	-1%	-3%
India	1.00	2.20	2.15	2.23	1.34	1.34	1.33	-2%	1%	-1%	-1%
Europe	1.00	1.23	1.21	1.17	0.92	0.90	0.90	-2%	-4%	-2%	-2%
FSU	1.00	1.48	1.43	1.35	0.95	0.97	0.98	-3%	-9%	2%	2%
Japan	1.00	1.58	1.55	1.50	1.11	1.11	1.10	-2%	-5%	0%	0%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

A7b. Results to 2100.

Region	BAU				High CO_2 Price			% Change from No PIB			
								BAU		High CO_2 Price	
	PIB	No PIB	PIB	PIB HP	No PIB	PIB	PIB HP	PIB	PIB HP	PIB	PIB HP
	2000	2100	2100	2100	2100	2100	2100	2100	2100	2100	2100
USA	1.00	2.60	2.50	2.4	1.46	1.41	1.31	-4%	-8%	-4%	-10%
China	1.00	4.47	4.28	4.2	1.73	1.64	1.50	-4%	-7%	-5%	-13%
India	1.00	5.21	4.99	4.8	2.38	2.22	2.05	-4%	-7%	-7%	-14%
Europe	1.00	1.69	1.63	1.6	1.02	1.00	0.97	-3%	-8%	-2%	-5%
FSU	1.00	2.11	2.01	1.9	1.22	1.21	1.24	-5%	-9%	0%	2%
Japan	1.00	2.78	2.65	2.5	1.41	1.36	1.29	-5%	-9%	-3%	-8%

* Universal, simultaneous participation, "*EPPA-Ref gas prices*" and "*Limited nuclear*".

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