Appendix B: Parameters and Data

Here we detail the parameters and assumptions used in the electricity sector extension with BEPAM-E. A description of the parameters and assumptions applied to the agricultural and transportation sectors is available in Chen et al. (2014).

1. Regional Electricity Demand

Linear demand curves are used to model the demand for electricity generated across the US. The model includes a demand curve for each the 20 EMRs. In order to construct these regional demand curves linear demand curves are calibrated for each state and each electricity demand sector. The electricity demand sectors include residential, industrial, commercial, and transportation. These demand curves are calibrated with the quantity of electricity consumed in a given sector in a given state for the year 2007, and the average price paid by that sector in that state for the generation in 2007 (Table B1) (EIA 2010a). These demand curves are all calibrated with the a price elasticity of demand with a value of -0.25 following Dubin and McFadden (1984) and EIA (2010b), which are at the low end of a range of estimates (Table B2).[1] These state and sector demand curves are then aggregated across all sectors and all states contained within a given an EMR to obtain aggregate demand curves for all retail sales of electricity in an EMR for 2007. Demand for electricity is assumed to grow at an annual rate of 0.7% following Annual Energy Outlook (AEO) (2012), for all EMRs across the time period of 2007-2030 (Table B3). Demand curves consider electricity generation from any source or within any region as functional equivalents.

2. Electricity Generation: Existing Power Plants

Existing power plants are represented in the model at the CRD level. These CRD level power plants are obtained by taking a sum of the nameplate capacity of all power plants located within a given CRD and taking a capacity weighted average of the plants' capacity factor and overall heat rate, where applicable by primary energy source. The data on power plant location, capacity, capacity factor, nominal heat rate, and primary fuel source are obtained from EPA's eGrid database for the year 2007 (Table B4). The energy sources considered are: coal, natural gas, oil, nuclear, hydroelectric, geothermal, solar, wind, biomass, municipal waste, and other. These power plants are classified into different generation sources based on their primary fuel usage. This classification determines whether or not they require an input fuel source in the model, and if so what type. These CRD-level parameters are used to calibrate two constraints that describe generation: a capacity constraint and a production function/constraint. The capacity constraint is specified for all energy technology types and doesn't allow more annual electricity generation than total nameplate capacity times the capacity factor times. The production function/constraint is only specified for generation technology types that require a fossil fuel input. This production function is specified as a linear production function where the fuel input times the inverse nominal heat rate must be less than or equal to the generation quantity. Power plants become more costly to operate as the age and eventually are retired, we represent this by imposing annual capacity retirement rates by plant type (Table B4). Retirement rates are calculated as the average of annual capacity retirement rates of plant by type from Electric Power Annual 2008-2010.

[1] Based on EIA's NEMS parameter for commercial sector demand elasticity.

The co-firing of coal and biomass from any source (energy crops, crop residues, or forest residues) is an option for any existing coal plant in the model. In order for a coal power plant to co-fire biomass it must convert some of it existing capacity for co-firing. The conversion cost is assumed to be $120/KW of capacity (EIA 2010b). Co-firing of biomass is constrained to be no more than 10% of energy equivalent coal use at a given power plant. Co-firing capacity expansion reduces coal capacity by displacing it with the biomass used, this necessitates that an increase in co-firing of biomass requires a decrease in coal use if the plant is being run at full capacity. Therefore, in this model co-firing provides a double benefit for GHG emissions generating electricity from a biomass and reducing coal emissions by an equivalent amount. This assumption differs from that of Latta et al. (2013), where coal capacity can increase for co-firing not yielding the dual GHG benefit shown in this model.

3. Electricity Generation: New Capacity

Generation of electricity from new power plant capacity is modeled at the EMR level, excluding co-firing. The quantity of generation from new power plants is determined endogenously for natural gas, wind, co-firing, dedicated biomass, and co-product sources, while the expansion of other sources (nuclear, hydroelectric, solar, geothermal, and waste) are specified exogenously according to projections from the EIA AEO (2010b).

The expansion of natural gas generation incurs both a levelized cost and an endogenous fuel cost. The levelized cost of natural gas based generation net of fuel cost includes the annualized capital cost, and annualized transmission cost as well as the fixed and variable O&M costs. The levelized cost is $83.10 for a conventional combined-cycle power plant and is obtained from EIA AEO (2010b) and an estimated fuel costs of $45.30/MWh are subtracted to result in a levelized cost net of fuel of $37.80/MWh (Table B5).

The cost of generation from new wind turbine capacity is represented by upward sloping supply curves for wind energy resources. The data used to estimate these supply curves are from intermediate results of the National Energy Modeling System (NEMS) on regional wind resources in terms of capacity, which was provided to the authors by EIA. These data are projections of the amount wind capacity that is available by region at multiples of a base capacity cost. We convert these capacity values to generation by multiplying by the ratio MWhs/MW per year and a capacity factor of 0.34 (Table B5). The base cost used $148/MWh from the EIA levelized cost (Table B5). The converted data are then in form of regional supply functions for MWhs of electricity from wind resources with a step-function functional form. In order to allow for more variation of the marginal cost of wind-based generation in between these discrete steps, these supply functions are linearized using ordinary least squares.

The cost of generation for dedicated biomass power plant capacity is a function of an energy content of biomass, a heat rate that represents the efficiency of converting biomass into electricity, the endogenous power plant-gate price of biomass, a levelized cost, and a processing cost. The energy content of all biomass feedstock is assumed to be 8600 Btu/lbs (Haq 2002).The heat rate assumed for dedicated biomass capacity is based on a thermal efficiency of 20% from Qin et al. (2006) for a biomass power plant where switchgrass is used as a feedstock. The levelized cost for a biomass power plant of $111/MWh is obtained from EIA AEO (2010b), which is estimated to be without fuel cost $71.90/MWh. The cost of processing biomass of $18/MT is found from the average cost of different processing techniques (Koppejan and Loo 2012).[2] The price of biomass feedstock is determined endogenously.

4. Biomass Transportation

The data used to represent cost of transporting biomass for bioelectricity are based on the distance of transportation and a cost per mile per ton of biomass. The data representing the distance from the centroid every CRD to any other CRD are estimated using ArcGIS software. The cost of transporting a ton of biomass is assumed to be $0.212/mile (Searcy et al. 2007). Thus the costs of transporting biomass from any CRD to any other CRD is represented in the model.

5. Natural Gas Supply

A national natural gas supply function is specified annually. Given that the model's starting year is 2007 and that there have been large changes in the natural gas market in north America in part due to the large expansion in shale gas extraction since then, we calibrate the annual natural gas supply curve based on observed data for 2007-2011 instead of having it increase or decrease at a fixed rate. The annual supply curves are calibrated based on annual production and average wholesale price (EIA 2010a), and a price elasticity of supply of 0.48 (Fischer 2010) selected as the median from a range of studies (Table B2). The specification of the supply curves for all years after 2011 are based on an AEO projected annual growth rate of 1.4% for price and quantity of natural gas (Table B3). Sources of natural gas demand apart from that of the electricity sector are specified exogenously for the years 2007-2011 based on observed consumption, a growth rate of 0.4% is specified for all years following 2011 based on AEO projections (EIA 2012).

The natural gas transmission, distribution, and markup parameter is used in the model to describe the difference between the wellhead price of natural gas and power plant-gate price of natural gas and the difference in this power plant-gate price of natural gas across regions. This parameter is calculated from the difference between the national average wellhead price of natural gas in 2007 and the weighted-average regional delivered price of natural gas in 2007 calculated from the State Energy Data System (EIA 2010a).

6. Electricity Transmission

All electricity that is generated must be transmitted and distributed to end-use consumers. Electricity generation incurs a transmission cost of $0.007 per kWh and a distribution cost of $0.021 per kWh (EIA 2007). There is also a loss of energy as it is transmitted to consumers that is assumed to be 8% following GREET (2013). Inter-regional electricity transmission between adjacent EMRs is allowed for. This inter-regional transmission is subject to transmission capacity constraints based on historically observed levels (EIA 2011).

7. Renewable Portfolio Standards

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[2] The processing techniques are: breaking and shredding, grinding, pulverization, mechanical separation, and pelletizing; converted to USD.

Renewable Portfolio Standards is generally a mandate that requires a minimum percentage of retail sales of electricity be generated from renewable energy sources. In this analysis RPSs described by existing law at the state level evaluated. State level RPSs data that describes existing legislation is obtained from DSIRE (2010). DSIRE maintains an extensive database of attributes of state level RPSs. This study utilizes the annual implementation schedule of RPSs, the load proportion of state generation that the RPS applies to, the qualifying renewable sources, the date at which the RPS becomes effective, and the dates at which the renewable energy capacity must have been built by in order to qualify from this database.

The RPSs are implemented by a schedule at which the RPS increases annually or bi-annually until it reaches its target rate. As annual data is necessary for the model, it is assumed that for states that have a bi-annual or irregular RPS implementation schedule that RPS increases linearly between any two years which the RPS is specified for. RPS reach their target maximum percentage at different years ranging from as early as 2016 to as late as 2025; it is assumed that this target RPS must be maintained for all succeeding years.

For a number of states renewable energy capacity built before a legally specified year does not qualify for the RPS. In order to adjust the RPS constraint in the model for this, we calculate a parameter that represents the amount of renewable generation not eligible for the RPS. This parameter is assumed to be the quantity of electricity generation from renewables energy sources in the year prior to eligibility from the State Energy Data System (2010a).

8. Life Cycle Analysis

Life cycle analysis, which determines all of the emissions incurred from using a particular fuel for electricity generation is used to estimate the GHG emission resulting from the from coal, natural gas, and oil based generation (Table B7). These values are: These electricity sector Life Cycle emission are added to a GHG accounting equation that captures the life-cycle emissions across the agricultural, transportation, and electricity sectors.

9. Learning by Doing

The model allows for learning- by-doing based on cumulative production with a technology to reduce the costs of production in the case of wind based electricity and dedicated bio-power plants. The quantity of wind based generation or dedicated biomass generation is used to update the cost of generation from these sources based on a technology specific learning rate. The annual learning rate for wind generation is 8% and 15% for dedicated bio-power (McDonald and Schrattenholzer 2001).

Table B1: Electricity price and consumption

State	Average Price 2007 ($/MWh)	Average Price 2011 ($/MWh)	Total Consumption 2007 (Thou. MWh)	Total Consumption 2011 (Thou. MWh)
AL	76.6	92.4	91828	88995
AR	70.2	75.1	47055	47928
AZ	85.4	97.1	77193	74944
CA	128.4	130.8	264235	261942
CO	77.8	94.2	51299	53458
CT	164.4	163.5	34129	29859
DC	117.9	128.0	12110	11562
DE	113.8	115.1	11869	11483
FL	103.3	106.1	231085	225090
GA	78.6	96.1	137454	136371
IA	68.3	75.6	45270	45655
ID	50.7	64.4	23755	23272
IL	84.8	90.0	146055	142886
IN	65.2	80.3	109420	105818
KS	68.5	89.1	40166	40760
KY	58.6	72.0	92404	89538
LA	84.5	77.7	79567	86369
MA	151.6	141.1	57139	55570
MD	115.0	119.3	65391	63600
ME	145.9	125.8	11860	11415
MI	85.4	104.3	109297	105054
MN	74.5	86.8	68231	68533
MO	65.6	83.2	85533	84255
MS	81.0	88.7	48153	49338
MT	71.7	82.8	15532	13788
NC	78.3	86.5	131881	131085
ND	64.3	75.1	11906	13737
NE	62.8	78.8	28248	29676
NH	139.8	147.4	11236	10869
NJ	130.3	143.1	81934	76860
NM	74.9	88.4	22267	23042
NV	100.2	90.2	35643	33916
NY	152.2	158.9	148178	144047
OH	79.4	90.6	161771	154746
OK	73.0	78.2	55193	59847
OR	70.1	80.4	48697	47171
PA	91.1	104.8	151573	148757
RI	131.1	130.4	8013	7732
SC	71.8	88.0	81948	80489
SD	68.9	80.5	10603	11680
TN	70.9	93.0	106717	100733
TX	101.8	90.9	343829	376065
UT	64.4	71.6	27785	28859
VA	71.3	88.4	111570	110228
VT	120.4	138.0	5864	5550
WA	63.9	68.3	85742	93725
WI	85.0	102.4	71301	68612
WV	53.6	79.0	34184	31239
WY	53.3	66.2	15536	17418

Table B2: Demand and Supply Elasticities

Function	Estimates	Sources
Electricity Demand	-0.25	(Acton, Mitchell, and Sohlberg 1980; Dubin and McFadden 1984; EIA 2010b; Espey and Espey 2004; Reiss and White 2005)
	-0.25 to -0.7	
Natural Gas Supply	0.48	(Dahl and Duggan 1996; Fischer 2010)
	0.09 - 3.10	

Table B3: Demand and Supply Growth Rates

	Growth rate (%)	Source
Regional Electricity demand	0.7	(EIA 2010b)
State Coal Price	1.4	(EIA 2012)
Natural Gas Production	1.4	(EIA 2012)
Non-electricity Natural Gas Demand	0.4	(EIA 2012)

Table B4: Attributes of Existing Power Plant Capacity

Generation Technology	Total capacity (MW)	Average Capacity Factor	Average Heat rate (MMBtu /MWh)	O&M Costs ($/MWh)	Average Fuel Cost ($/MWh)	Average Cost ($/MWh)	Capacity Retirement Rate (Annual)	References
Existing capacity								
Coal	374067	0.59	10.42	5.50	21.83	27.33	0.27%	Capacity, capacity factor, and heat rate: EPA (USEPA 2010)[3]. O&M costs: (UCS 2011)[4]. Fuel price: (EIA 2010a).[5] Retirement Rate: (EIA, 2008-2010).[6]
Geothermal	3181	0.57		32.50		32.50	0.22%	
Hydroelectric	97031	0.30		5.90		5.90	0.01%	
Natural Gas	429740	0.16	9.90	5.20	70.85	76.05	0.75%	
Nuclear	107270	0.88		19.40		19.40		
Fuel Oil	33554	0.04	12.66	3.80	115.38	119.18	2.12%	
Other	2655	0.41		3.80		3.80	1.53%	
Solar	448	0.16		6.40		6.40		
Waste	1023	0.55		11.20		11.20		
Wind	15823	0.26		17.60		17.60	0.01%	

[3] In the model capacity is summed by technology type and CRD, a CRD weighted average heat rate is found by technology type, weighted by 2007 net generation.
[4] Fixed O&M cost that are given in $/MW are converted to $/MWh based on an average capacity factor by technology.
[5] These are delivered fuel prices for the electric power sector by state.
[6] Found by calculating the average of the annual retirement rate by power plant type from EIA Electric Power Annual 2008-2010.

Table B5: Attributes of New Power Plant Capacity

Generation Technology	Total capacity (MW)	Average Capacity Factor	Average Heat rate (MMBtu /MWh)	O&M, Levelized, or capital cost	Estimated Fuel Cost[7] ($/MWh)	Average Cost	Learning Rates (%)	References
New capacity								
Natural Gas			9.26	$37.8 /MWh	44.3	$82.1 /MWh		Heat rate: (UCS 2011)[8] Levelized cost: (AEO, 2010).[9]
Co-firing	0 - 37406[10]	0.59	10.42	$5.5/MWh +$120/kW	49.5	$55.0/MWh + $120/kW		Capacity, capacity factor, and heat rate for coal: EPA (2010).[11]
Co-product			125	n/a	n/a			Heat rate: (Humbird et al. 2011)[12]
Dedicated Biomass			17	$71.9 /MWh	80.5	$152.4 /MWh	10%	Heat rate: Qin et al. (2006),[13] levelized cost EIA (AEO, 2010)[14]
Wind				$148 /MWh		$148.0 /MWh	8%	Levelized cost EIA AEO (2010). [15] Data from EIA NEMS.[16]

[7] Using 2011 electricity sector natural gas price of $4.78/MMBtu, and a delivered and processed price of biomass of $90/MT.
[8] For conventional combustion turbine.
[9] The levelized cost used here is net of estimated fuel costs, and therefore represents capital, O&M, and transmission costs.
[10] It is assumed that co-firing may use up to 10% of existing coal capacity, corresponding with an equivalent decrease in coal capacity.
[11] Co-fired biomass is assumed to burn at the same efficiency as coal at that plant. Qin et al. (2006) finds that co-firing has about a 32% thermal efficiency for switchgrass at the 10% level.
[12] Converted from gallons based on 83 gallons per MT.
[13] Where 100% switchgrass feedstock is fired at 20% thermal efficiency.
[14] The levelized cost used here is net of estimated fuel costs, and therefore represents capital, O&M, and transmission costs.
[15] The levelized cost is used as a base cost parameter to calibrate the wind supply functions.
[16] Regional wind availability data were provided to the authors by the EIA, which are from intermediate results of the National Energy Modeling System (NEMS). These data are in the form of wind capacity by region available at multiples of a base cost.

Table B6: Learning Rates

Learning Curve parameter	Wind	Dedicated biomass	Data Sources
Initial Cost ($/MWh)	148	71.9	(EIA 2010b)
Learning rate (%)	8	15	(McDonald and Schrattenholzer 2001)
Initial stock of generation (M MWh)	383.0	776.2	Authors' estimate[17]

[17] Cumulative generation of all wind energy or bioenergy for all sectors, from 1990-2010, EIA detailed State Data System.

Table B7: Life-Cycle Emissions for Electricity Generation

	GHG Intensity with no Soil Carbon or iLUC	GHG Intensity with Soil Carbon but no iLUC[18]	iLUC[19]
Electricity (lbs co2e/MWh)			
Renewables			
Corn stover co-firing	107.79	107.79	0
Corn stover dedicated biomass	175.87	175.87	0
Wheat straw co-firing	122.11	122.11	0
Wheat straw dedicated biomass	199.23	199.23	0
Switchgrass co-firing	123.04	-242.80	109.65 (107.29-274.23)
Switchgrass dedicated biomass	200.74	-396.12	178.89 (65.76-168.09)
Miscanthus co-firing	46.41	-319.44	109.65 (107.29-274.23)
Miscanthus dedicated biomass	75.71	-586.61	178.89 (65.76-168.09)
Forest residue co-firing	0	-	0
Forest residue dedicated biomass	0	-	0
Wind	-	-	-
Fossil Fuels[20]			
Coal	2360	-	-
Natural Gas	1114.6	-	-
Fuel Oil	2425.1	-	-

[18] Carbon soil sequestration rates of are obtained from the DAYCENT model (Dwivedi et al. 2015), and are 8.8 MT CO2e/ha/year and 5.3 MT CO2e/ha/year for miscanthus and switchgrass, respectively.

[19] The effect of indirect land use change (iLUC) on biofuel GHG intensity is obtained from RFS II (EPA 2010) and we assume switchgrass-based biodiesel and biofuels derived from miscanthus all have the same iLUC effect as switchgrass-base ethanol does.

[20] Life-cycle emission for electricity generation from fossil fuels obtained from GREET (2013).

Table B8: US Natural Gas Wellhead prices

Year	Price ($/MMBtu)
2007	6.11
2008	7.79
2009	3.59
2010	4.38
2011	3.86

Table B9: Average Biofuel GHG Intensities at the National Level

	GHG Intensity with no Soil Carbon or iLUC	GHG Intensity with Soil Carbon but no iLUC[21]	iLUC[22]
Biofuel (lbs/MMBtu)			
Corn ethanol	141.79	135.72	70.55 (46.31–101.41)
Soybean diesel	106.62	81.71	94.81 (33.08–167.57)
Sugarcane ethanol[23]	60.64	58.43	8.82 (-11.00–26.45)
Corn stover ethanol	32.52	32.52	0
Corn stover diesel	30.73	30.73	0
Wheat straw ethanol	36.84	36.84	0
Wheat straw diesel	35.36	35.36	0
Switchgrass ethanol[24]	37.12	-73.25	33.08 (19.84–50.71)
Switchgrass diesel	37.26	-83.40	33.08 (19.84–50.71)
Miscanthus ethanol	14	-108.47	33.08 (19.84–50.71)
Miscanthus diesel	10.58	-123.32	33.08 (19.84–50.71)
Forest residue ethanol[25]	49.78	49.78	0
Forest residue diesel[26]	17.12	17.12	0
DDGS diesel[27]	28.28	28.28	0
Waste grease diesel[28]	29.94	29.94	0
Gasoline[29] (2005 baseline)	216.53		-
Diesel (2005 baseline)	213.88		-

[21] Carbon soil sequestration rates are obtained from the DAYCENT model (Dwivedi et al. 2015), and are 8.8 MT CO2e/ha/year and 5.3 MT CO2e/ha/year for miscanthus and switchgrass, respectively.

[22] The effect of indirect land use change (iLUC) on biofuel GHG intensity is obtained from RFS II (EPA 2010) and we assume switchgrass-based biodiesel and biofuels derived from miscanthus all have the same iLUC effect as switchgrass-base ethanol does.

[23] Obtained from Crago et al. (2010)

[24] These national averages exclude the states where switchgrass is unlikely to be commercially produced; these states are: all the ten western states, Minnesota, and Wisconsin.

[25] Obtained from CARB LCFS report (CARB 2009).

[26] Based on the GHG intensity value for stover-based diesel in RFS II final rule (EPA 2010).

[27] Based on the emissions from soybean oil and corn oil to diesel conversion and fuel transport GREET 1.8c.

[28] Obtained from RFS II (EPA 2010)

[29] Obtained from Rubin and Leiby (2013).

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