MEMORANDUM

TO: Clean and Renewable Energy Subcommittee members

FROM: Hal Nelson

CC: Donna Boysen, John Warmerdam, Tom Peterson

DATE: May 12th, 2008

RE: Energy Supply Assumptions

The purpose of this memo is to present the range of assumptions that need to be determined for the quantification process, as well to begin to gain some consensus on which assumptions should be used. This memo defines the assumptions and a follow-up memo will review the options selected so that everyone can be on the same page as the modeling moves forward. In terms of the process for development of these assumptions, I suggest that we proceed under the following steps. Members of the subcommittee who want to suggest data for the assumptions should send their recommendations to the subcommittee and the CCS technical team. We will compile the suggestions and facilitate a discussion on them in a later conference call to gain consensus on preferred assumptions.

Quantifying and forecasting reductions of CO_2 from the power sector adds another layer of complexity to an already complex sector. Assumptions are important in that they are drivers of the models' cost estimates of the policy proposals. Models are representations of reality, and require the best available data on likely futures. That being said, the future rarely looks like what models say it will (consider current oil prices). Thus, a premium should be placed on choosing assumptions that mesh with current conditions and near term forecasts, as well as assumptions that are generated using local or regional data rather than national level data.

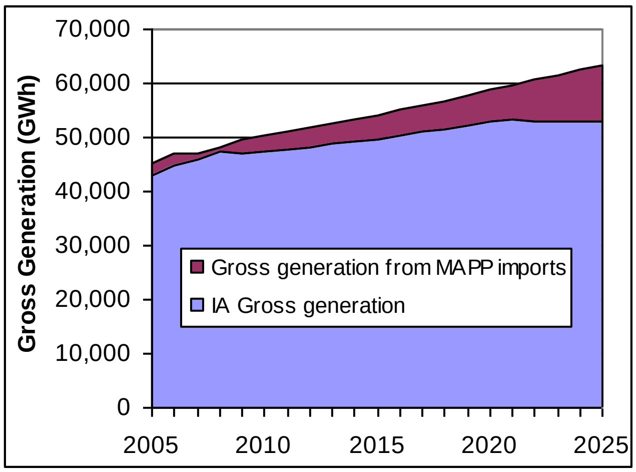
Load growth

The most important planning variable is load growth. Load growth impounds a host of additional assumptions including economic growth, energy efficiency deployment, migration, and others. The 2007 *Annual Energy Outlook* forecast shows the MAPP region demand growing at 1.1% year, while the IUB estimates for Midamerican and Interstate combined are 1.7% over the planning period. In contrast, the Energy Efficiency subcommittee is targeting energy efficiency deployment of 2% of sales by 2015 in several of its policy options. If the subcommittee decides that it wants to do sensitivity analysis, this is one parameter that is a likely candidate for a low-medium-high range to be established.

Forecast	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average
IA (MidAm&Interstate) Sales Forecast	2.79%	2.93%	1.76%	1.57%	1.40%	1.47%	1.52%	1.57%	1.57%	1.58%	1.64%	1.69%	1.58%	1.64%	1.56%	1.51%	1.55%	1.54%	1.71%
MAPP Sales Forecast	2.17%	1.66%	1.19%	1.21%	1.44%	1.18%	1.13%	1.15%	1.15%	0.80%	0.83%	1.00%	1.01%	0.79%	0.96%	0.77%	0.91%	0.93%	1.13%

Imports

The draft IA Forecast shows imports increasing from 5% to 20% of load by 2030. This is a result of the constraint in the Forecast that IA generation will only grow at the MAPP rate (1%). As a result, CO_2 emissions from imports climb from 1.5 MT in 2000 to almost 10 MT in 2030. The subcommittee can discuss whether the assumed constraint on the ability of IA to site new plant is congruent with current practices in the state. Similarly, does the assumption of the CO_2 intensity of .78 tonnes/MWh (1,700 lbs/MWh) for imports from the MAPP region seem reasonable?



New build mix and retirements

The subcommittee is requested to specify the mix of fossil and renewables technologies deployed to meet load growth. The table below from the IA Forecast shows the assumption that IA new build mirrors the MAPP region. The CRE subcommittee is requested to assess this assumption under two conditions:

1) A "No Policy" case based on planned additions under BAU: eg 50% coal, 40% gas, 10% wind.

2) The new build mix for the renewable policy options under discussion: eg: 75% wind, 20% biomass, etc.

Included in the new build mix should be any capacity retirements, and what the new build mix is then used to replace retirements.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	77%	78%	77%	76%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	77%	78%	78%	79%	79%
Nuclear	11%	10%	10%	10%	10%	10%	10%	10%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
Natural Gas	6%	2%	2%	4%	2%	2%	2%	2%	2%	2%	3%	3%	4%	3%	4%	4%	4%	3%	3%
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MSW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Biomass	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LFG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wind	4%	6%	7%	7%	7%	7%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Hydro	2%	3%	3%	3%	3%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Capital costs and capacity factors of new build

Estimates of capital costs and capacity factors for new generating capacity vary tremendously and the quantification process requires some guidance as to which estimates the CRE subcommittee prefers. Again, IA specific estimates are preferred. The following table from the *Annual Energy Outlook* 2007 shows the capital cost and O & M costs used by the National Energy Modeling System (NEMS) model.

Table 39. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2006 ($2005/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2006[3] (2005 $/kW)	Variable O&M[4] ($2005 mills/kWh)	Fixed O&M[5] ($2005/kW)	Heatrate in 2006 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWh)
Scrubbed Coal New[7]	2010	600	4	1,206	1.07	1.00	1,290	4.32	25.91	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2010	550	4	1,394	1.07	1.00	1,491	2.75	36.38	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,936	1.07	1.03	2,134	4.18	42.82	9,713	7,920
Conv Gas/Oil Comb Cycle	2009	250	3	574	1.05	1.00	603	1.94	11.75	7,163	6,800
Adv Gas/Oil Comb Cycle (CC)	2009	400	3	550	1.08	1.00	594	1.88	11.01	6,717	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,055	1.08	1.04	1,185	2.77	18.72	8,547	7,493
Conv Combustion Turbine[8]	2008	160	2	400	1.05	1.00	420	3.38	11.40	10,807	10,450
Adv Combustion Turbine	2008	230	2	379	1.05	1.00	398	2.98	9.91	9,166	8,550
Fuel Cells	2009	10	3	3,913	1.05	1.10	4,520	45.09	5.32	7,873	6,960
Advanced Nuclear	2014	1350	6	1,802	1.10	1.05	2,081	0.47	63.88	10,400	10,400
Distributed Generation -Base	2009	2	3	818	1.05	1.00	859	6.70	15.08	9,500	8,900
Distributed Generation -Peak	2008	1	2	983	1.05	1.00	1,032	6.70	15.08	10,634	9,880
Biomass	2010	80	4	1,714	1.07	1.02	1,869	2.96	50.18	8,911	8,911
MSW - Landfill Gas	2009	30	3	1,491	1.07	1.00	1,595	0.01	107.50	13,648	13,648
Geothermal[6,7]	2010	50	4	1,790	1.05	1.00	1,880	0.00	154.92	36,025	30,641
Conventional Hydropower[8]	2010	500	4	1,364	1.10	1.00	1,500	3.30	13.14	10,107	10,107
Wind	2009	50	3	1,127	1.07	1.00	1,206	0.00	28.51	10,280	10,280
Solar Thermal[7]	2009	100	3	2,675	1.07	1.10	3,149	0.00	53.43	10,280	10,280
Photovoltaic[7]	2008	5	2	4,114	1.05	1.10	4,751	0.00	10.99	10,280	10,280

Source: Assumptions to the AEO 2007, p. 77.[1]

Another consideration relates to the inclusion of learning curves or cost escalation factors for new capital equipment. The recent demand for wind turbines and other generation equipment has driven up their price in the short term. In the long term, some technologies are likely to continue to experience cost reductions on a kW basis due to economies of scale (production doubling, etc). Below is a table from the AEO 2007 that shows the figures used in the NEMS for learning curves.

[1] http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf

Table 72. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies in Three Cases (2004$/kW)

Technology	Year	Reference	High Renewables[1]	Low Renewables
Geothermal[2]	2010	1,675	1,675	1,709
	2020	2,392	2,392	2,572
	2030	2,298	2,308	2,572
Hydroelectric[2]	2010	1,485	1,441	1,500
	2020	1,426	1,344	1,485
	2030	1,396	1,235	1,485
Landfill Gas	2010	1,579	1,547	1,595
	2020	1,531	1,436	1,595
	2030	1,499	1,436	1,595
Photovoltaic[3]	2010	4,105	4,020	4,276
	2020	3,569	3,317	4,198
	2030	2,923	2,628	4,004
Solar Thermal[3]	2010	2,527	2,527	2,808
	2020	2,309	2,198	2,782
	2030	2,067	1,792	2,757
Biomass[4]	2010	1,833	1,729	1,852
	2020	1,721	1,516	1,777
	2030	1,534	1,304	1,646
Wind	2010	1,194	1,182	1,206
	2020	1,194	1,122	1,206
	2030	1,194	1,086	1,206

Source: Assumptions to the AEO 2007, p. 142

Renewables Incentives

What does the CRE subcommittee assume is going to happen to the federal production tax credit (PTC) and should it be included in the levelized cost estimates for renewables in the Policy Options? The federal Renewable Electricity Production Tax Credit has been around in some form since 1992 but seems to always be about to expire (currently December, 2008). The existing incentive for wind, closed-loop biomass and geothermal is 2.0¢/kWh. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources receives a 1.0¢/kWh credit. Also, the IA Renewable Energy Tax Credits under IA Code Chapters 476B/C provide tax incentives for renewable electricity.

Fuel Prices

The following table shows fuel prices for delivered costs in the MAPP region from the *AEO* 2007. The NEMS model has been criticized for its forecasts "mean reverting", or underestimating sustained fuel price increases and declines.[2] Given that oil prices are above $110 per barrel on the NYMEX futures market through 2015, it would appear that the NEMS is still providing forecasts that understate likely future energy price volatility. The 2008 *AEO* should be out within the next month with updated fuel price forecasts, but other forecasts are welcome.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel Prices (dollars per million Btu)																			
Coal	1.12	1.15	1.14	1.25	1.44	1.42	1.40	1.32	1.27	1.26	1.26	1.36	1.27	1.28	1.28	1.26	1.26	1.27	1.29
Natural Gas	7.25	6.82	6.27	5.97	5.60	5.44	5.19	5.23	5.17	5.26	5.47	5.36	5.30	5.43	5.38	5.50	5.63	5.69	5.68
Distillate Fuel Oil	15.86	11.62	10.89	10.03	9.31	8.88	8.65	8.40	8.39	8.30	8.54	8.64	8.91	8.94	9.09	9.18	9.12	9.22	9.20
Residual Fuel Oil	7.57	7.08	6.48	5.98	5.58	5.22	5.06	4.90	4.96	4.96	5.09	5.12	5.31	5.37	5.48	5.60	5.55	5.68	5.70
Biomass	1.43	1.72	1.80	1.79	1.81	1.85	1.85	1.87	1.88	1.88	1.92	1.94	1.94	1.89	1.88	1.87	1.89	1.92	1.92

[2] Bolinger, M., Wiser, R. (2005). Memo: Comparison of AEO 2006 Natural Gas Price Forecast to NYMEX Futures Prices. Berekely: LBNL. Also see: http://www.eia.doe.gov/oiaf/analysispaper/retrospective/retrospective_review.html