Memo-Draft

To: Alaska Forestry, Agriculture, and Waste Technical Working Group

From: The Center for Climate Strategies

Subject: Assumptions for FAW Mitigation Policy Options Quantification

Date: December 11, 2008

This memo summarizes key assumptions used to estimate the greenhouse gas (GHG) reductions and cost effectiveness for draft Forestry, Agriculture, and Waste (FAW) policy options. The quantification process is intended to support custom design and analysis of draft policy options, and provide both consistency and flexibility. The purpose of this memo is to present the assumptions used as part of the quantification process in order to ensure consistency between options and between subcommittees. Feedback on the assumptions is encouraged.

Quantifying reductions of GHG (particularly future reductions) is an inherently complex process and assumptions are important inputs into the quantification methodologies and models used to estimate policy costs and benefits. Models are representations of reality and require the best available data on likely futures. An emphasis should be placed on using assumptions that are based on the best available data using local or regional data (when available) rather than national level data.

Unless directed otherwise by the Alaska Climate Change Mitigation Advisory Group (CCMAG), CCS will estimate the full fuel or product cycle GHG reductions for each policy option, where data and methods are available to do so. In the AK GHG Inventory and Forecast (I&F), the only sector for which consumption-based emissions data are provided is the electricity consumption sector (and in the case of AK, these are equivalent to production based emissions since there is no import/export of electric power). In other sectors of the inventory, the GHG emissions are strictly those that occur within the state as a result of energy consumption or other GHG emission process (e.g. methane from landfilled waste). For example, for fuel combustion in the RCI and Transportation sectors, only the emissions associated with fuel combustion are provided, not those associated with the extraction, transport, processing, and distribution of each fuel (i.e. “full fuel cycle” emissions). Similarly, for waste management, only emissions associated with waste management processes in AK are included in the I&F (e.g. landfilling, waste combustion), not those associated with production and transportation of the initial packaging or product that became a component of the solid waste stream (i.e. “full product cycle” emissions).

In addressing full fuel/product cycle emission reductions, there are limitations that need to be understood. For example, for a policy that calls for implementation of technologies to efficiently use biomass for energy production, the GHG reductions associated with the full fuel cycles of the fossil fuels displaced would be considered; however, the GHG emissions associated with the manufacture and installation of the new biomass energy plant would not be addressed. This is due to the many complexities and data challenges of estimating these emissions. Similarly, for an option that covers higher levels of municipal solid waste recycling, the embedded GHG associated with recycled products/packaging are considered and compared to products/packaging made from virgin materials; however, the GHG emissions associated with the construction of material recovery facilities and other recycling infrastructure are not captured.

Development of consumption-based emission estimates (including embedded GHG from full fuel/product cycle assessments) for all sectors of the inventory are beyond the scope of this process. Indeed, in many cases, these types of inventory estimates would involve significant technical and data availability challenges. However, for some policy options, full fuel cycle/product emission reductions can be estimated, and it should be recognized that the portion of emission reductions that occur out of state as a result of in-state policies are not captured in the I&F. Some might see these methodological differences in emissions and emission reductions accounting as a disconnect; however, CCS believes that the CCMAG should consider taking credit for reductions that occur out of state as a result of actions taken within the state. Some common examples of where this accounting occurs:

- Fossil fuel consumption: inventory estimates are based only on the GHG emissions associated with the combustion of each fuel; full fuel cycle emission reductions are estimated using GHGs from combustion plus the embedded GHGs from extraction, transportation, processing, and distribution;
- Solid waste management: landfill methane emissions or total GHG emissions are associated only with waste combustion and decomposition; full product cycle emission reductions include the landfill/waste combustion emissions plus those associated with production of the packaging or product (i.e. net difference of use of virgin materials versus recycled materials);
- Biofuels consumption: for fossil fuel displacement benefits, the inventory includes only GHGs from fossil fuel combustion; full fuel cycle emission reductions are estimated using the fuel cycle gasoline/diesel emission factors compared to fuel cycle biofuel emission factors (captures total GHGs from fuel production, processing, and distribution).

Biomass Supply

The table below is a preliminary table that has been developed for AK on biomass availability. The source/reference for the value is indicated in the notes section. CCS will work with the FAW TWG to continue development of this table for AK, which will be needed to address not only FAW policy options, but biomass related options in other TWGs as well.

Biomass Resource	Annual Biomass Supply (Dry Tons)	Notes
Logging Residue	738,000	2005 NREL Report.1 Derived from the USDA Forest Service's Timber Product Output database for 2002.
Primary Mill Residue (Unused)	131,000	2005 NREL Report. Derived from the USDA Forest Service's Timber Product Output database for 2002, includes mill residues burned as waste or landfilled.
Secondary Mill Residue	2,000	2005 NREL Report. Derived from data on the number of businesses that was gathered from the U.S. Census Bureau, 2002 County Business Patterns. Includes woods scraps and sawdust from woodworking shops – furniture factories, container and pallet mills, and wholesale lumberyards.
Urban Wood Waste	65,000	2005 NREL Report. Includes MSW wood, utility tree trimming and/or private tree companies, and construction/demolition wood.
Agricultural Residue and Vegetable and Fruit Waste	0	2005 NREL Report. Estimated using 2002 total grain production, crop to residue ratio, moisture content, and taking into consideration the amount of residue left on the field for soil protection, grazing, and other agricultural activities.
Energy Crops	0	2005 NREL Report.
Willow and Hybrid Poplar or Other Fast-growing Hardwoods	0	2005 NREL Report.
Municipal Solid Waste (MSW) Fiber	TBD	Other than Urban Wood Waste. Will be forecast to 2025 based on input from TWG and DEC
Yard and Landscape Waste Debris	TBD	Other than Urban Wood Waste. Will be forecast to 2025 based on input from TWG and DEC
Total Annual Biomass Supply	**936,000**	

Emission Factors

Standard emissions factors for fuel feedstocks are calculated from the Alaska GHG Emissions Inventory and summarized below (note that these emission factors include CH_4 and N_2O emissions in addition to CO_2 emissions). Note that these emission factors are not full fuel cycle emission factors. The FAW TWG will use the values used by either the Energy Supply & Demand (ESD) TWG or the Transportation & Land Use (TLU) TWG depending on the fuel involved.

Feedstock	**(tCO_2e/MMBtu)**
Sub-bituminous coal	0.096
Natural gas	0.054
Residual oil	0.078
Diesel oil	0.073
Petroleum coke	0.100
LPG	0.063

[1] A. Milbrandt. *A Geographic Perspective on the Current Biomass Resource Availability in the United States.* Technical Report NREL/TP-560-39181. Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory, December 2005. Available at: www.nrel.gov/docs/fy06osti/39181.pdf.

Feedstock	(tCO_2e/MMBtu)
Refuse derived fuel (fossil)	0.043
MSW (fossil)	0.043
Refuse derived fuel (biomass)	0.002
MSW (biomass)	0.002
Wood, waste wood and sawdust	0.002
Nuclear	0.000
Landfill gas[2]	0.000
Wind	0.000
Solar/PV	0.000
Other	0.054
Oil	0.078
Waste solvent	0.073

The emissions factor for grid electricity was also taken from the draft AK I&F, derived by dividing total electricity consumption emissions in 2005 by electricity sales in 2005. This provided an Electricity Emissions Factor of 0.523 tCO_2e per MWh in 2005. Emission factors for future years will also be taken from the final I&F and used consistently across each TWG.

Fuel Prices

The following table shows fuel prices (in $/MMBtu) for costs taken from Annual Energy Outlook 2008 (Early Release)[3]. The FAW TWG will work with the ESD and TLU TWGs to assure that a consistent set of forecast fuel prices is being used.

Year	Distillate Fuel ($/MMBtu)	Natural Gas ($/MMBtu)	Coal ($/MMBtu)	Coal ($/ton)
2009	$13.25	$6.82	$1.20	$30.10
2010	$12.65	$6.36	$1.24	$30.99
2011	$12.11	$6.07	$1.24	$31.11
2012	$11.33	$5.86	$1.23	$30.67
2013	$10.68	$5.60	$1.22	$30.56
2014	$10.41	$5.43	$1.23	$30.66
2015	$9.83	$5.32	$1.22	$30.47
2016	$9.42	$5.29	$1.21	$30.28
2017	$9.43	$5.34	$1.22	$30.39
2018	$9.57	$5.39	$1.25	$31.21
2019	$9.71	$5.42	$1.25	$31.30
2020	$9.81	$5.24	$1.26	$31.51

[2] This includes carbon that is primarily biogenic; so except for very small amounts of methane and nitrous oxide would be considered non-GHG.
[3] Fuel cost (in $/MMBtu) come from Figure 1. Energy Prices 2006 dollars per million Btu from EIA AEO 2008, see http://www.eia.doe.gov/oiaf/aeo/prices.html.

Assumed cost of electricity is based on Future Pacific Census Division Electricity prices from the EIA Annual Energy Outlook (see http://www.eia.doe.gov/oiaf/aeo/supplement/index.html), illustrated below. As mentioned above for fuel prices, the FAW TWG will work with the ESD TWG to assure a common set of forecasted electricity prices.

U.S. Census Division 09 - Pacific	
Year	**All Sector Average Electricity Price (2005$ per kWh)**
2009	0.10
2010	0.10
2011	0.10
2012	0.10
2013	0.09
2014	0.09
2015	0.09
2016	0.09
2017	0.09
2018	0.09
2019	0.09
2020	0.09
2021	0.09
2022	0.09
2023	0.09
2024	0.09
2025	0.09

Capital costs and capacity factors

Estimates of capital costs and capacity factors for new generating capacity vary tremendously. 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. The FAW TWG will work with the ESD TWG to assure a common set of assumed costs for new generation.

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[5] ($2005 mills/kWh)	Fixed O&M[5] ($2005/kW)	Heatrate in 2006 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
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[5]	2008	160	2	400	1.05	1.00	420	3.36	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[6]	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.[4]

Renewable Incentives

Inclusion of the federal production tax credit (PTC) in the levelized cost estimates for renewables in the Policy Options needs to be considered. The federal Renewable Electricity Production Tax Credit has been around in some form since 1992 but seems always to be about to expire (extended to December 2009 by the Emergency Economic Stabilization Act of 2008 on October 3, 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.[5]

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4 http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf

5 "Closed-loop biomass" means "any organic material from a plant which is planted exclusively for purposes of being used at a qualified facility to produce electricity."

"Open-loop biomass" means:

"(i) any agricultural livestock waste nutrients, or

"(ii) any solid, nonhazardous, cellulosic waste material which is segregated from other waste materials and which is derived from -

"(I) any of the following forest-related resources: mill and harvesting residues, precommercial thinnings, slash, and brush,

"(II) solid wood waste materials, including waste pallets, crates, dunnage, manufacturing and construction wood wastes (other than pressure-treated, chemically-treated, or painted wood wastes), and landscape or right-of-way tree trimmings, but not including municipal solid waste, gas derived from the bio-degradation of solid waste, or paper which is commonly recycled, or

"(III) agriculture sources, including orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues.

"Such term shall not include closed-loop biomass or biomass burned in conjunction with fossil fuel (co-firing) beyond such fossil fuel required for startup and flame stabilization."

Biofuels

Full Fuel Cycle Emission Factors

The full fuel cycle emission factors are derived from the Argonne National Laboratory GREET 1.8b model for the year 2010 and utilize the model's default assumptions except where noted (downloadable from http://www.transportation.anl.gov/software/GREET/). The factors assume an average fuel economy of 100 miles/4.3 gallons (23.2 mpg) for gasoline-powered vehicles and 100 miles/3.6 gallons (27.8 mpg) for diesel-powered engines, based on the 2005 model year average. The full fuel-cycle emission factor for gasoline is 11.3 tCO_2e/1,000 gallons. This number assumes a mix of 50% conventional gasoline and 50% reformulated gasoline. The life-cycle emission factor for low-sulfur diesel is 11.3 tCO_2e/1,000 gallons.

The full fuel cycle emission factor for 100% corn ethanol is 9.1 tCO_2e/1,000 gallons. This value includes 195 gCO_2e /bushel emissions for land use change due to corn farming.

The full fuel cycle emission factor for cellulosic ethanol is 1.51 tCO_2e/1,000 gallons. This number assumes a mix of 25% herbaceous biomass, 25% forest residue, 25% corn stover, and 25% woody biomass (from farmed trees).

The full fuel cycle emission factor for soybean-based biodiesel is 0.667 tCO_2e/1,000 gallons.

Carbon emissions from land use change

Recent publications such as Searchinger, et al., 2008[6] (, have attempted to estimate the carbon emissions that result from land use being converted to cropland to grow crops for fuel. This is based on the argument that the conversion of current cropland from food/feed/fiber production in one part of the world will drop the food/feed/fiber supply on the world market and drive grassland or forest conversion to cropland in other parts of the world. There is still significant uncertainty regarding not only the overall argument, but also the corresponding levels of carbon emissions due to land use change. Hence, at this time emissions from land use change in developing nations are not incorporated into the overall quantification of GHG benefits.

Methods, Assumptions, and Data Sources for Quantitative Analysis

Waste Management Sector

CCS utilizes the EPA Waste Reduction Model (WARM) to estimate the life-cycle GHG benefit of waste diversion strategies, such as source reduction, recycling, and composting.[7] The

[6] Searchinger et al., Sciencexpress, "Use of U.S. Croplands for Biofuels Increases Greenhouse Gases through Emissions from Land Use Change," February 7, 2008).

[7] U.S. Environmental Protection Agency. WAste Reduction Model (WARM)." Version 8, May 2006. Available at: http://www.epa.gov/climatechange//wycd/waste/calculators/WARM_home.html. EPA created WARM to help solid waste planners and organizations track and voluntarily report GHG emission reductions from several different waste management practices. WARM is available as a Web-based calculator and as a Microsoft Excel spreadsheet. WARM calculates and totals GHG emissions of baseline and alternative waste management practices—source reduction, recycling, combustion, composting, and landfilling. The model calculates emissions in tCe, tCO_2e, and energy units (MMBtu) across a wide range of material types commonly found in MSW. For an explanation of the methodology, see the EPA report *Solid Waste Management and Greenhouse Gases: A Life-Cycle Assessment of*

business-as-usual (BAU) model inputs will be based on Alaska waste management data provided by DEC and the FAW TWG. The goals designed by the FAW TWG will be applied to the waste management projections completed by CCS and compared to the results of the BAU modeling to determine the incremental GHG benefit of increased waste reduction.

CCS will calculate the net cost-effectiveness for incremental waste diversion by considering the additional costs (collection costs, capital, operation and maintenance) and potential cost benefits (market value of recycled material, net tip-fee savings). For other states, CCS has used a value of $129/household for recycling program capital costs, based on an analysis in Vermont.[8] CCS will research the availability of capital cost data specific to Alaska to determine whether more state-specific data are available. Current US market prices for recycled materials are available from the RecycleNet.[9] This service reports current prices for materials such as scrap metal and scrap plastic, as well as, curbside recyclables, including newspapers, office paper, loose waste paper, PET, HDPE, aluminum, steel cans, and glass. If Alaska data are identified, these will be used to supplant the national data.

Emissions and Sinks, EPA530-R-02-006, May 2002. Available at: http://epa.gov/climatechange/wycd/waste/SWMGHGreport.html

[8] P. Calabrese, Cassella Waste Management, personal communication, S. Roe, CCS, 2007.

[9] RecycleNet Spot Market Pricing, http://www.scrapindex.com/index.html.