# Memo-Draft

**To:** Michigan Agriculture, Forestry and Waste Technical Work Group

**From:** The Center for Climate Strategies

**Subject:** Assumptions for Agriculture, Forestry and Waste Mitigation Policy Options

**Date:** August 2, 2008

This memo summarizes key assumptions used to estimate the greenhouse gas (GHG) impacts and cost effectiveness for draft Agriculture Forestry and Waste 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 Technical Work Groups (TWG). 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 Michigan Climate Action Council (MCAC), the Center for Climate Strategies (CCS) will estimate the lifecycle GHG reductions for each policy option, where data and methods are available to do so. In the MI GHG Inventory and Forecast (I&F), the only sector for which consumption-based emissions data are provided is the electricity consumption sector. In all 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 Residential, Commercial, and Industrial (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. Similarly, for waste management, only emissions associated with waste management processes in MI 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.

Development of consumption-based emission estimates (including embedded GHG from lifecycle 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, lifecycle 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 MCAC should consider taking credit for reductions that occur out of state as a result of actions taken within the state of MI. 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; lifecycle 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; lifecycle emission reductions include the landfill/waste combustion emissions plus those associated with production of the packaging or product (e.g. 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; lifecycle emission reductions are estimated using the lifecycle gasoline/diesel emission factors compared to lifecycle biofuel emission factors (captures total GHGs from fuel production, processing, and distribution).

## Biomass Supply

The table below indicates the biomass availability in Michigan. The source/reference for the value is indicated in the notes section. The AFW TWG will work to refine this initial assessment during the process.

| Biomass Resource | Annual Biomass Supply (dry tons) | Notes |
|---|---|---|
| Forest Residue | 1,275,000 | 2005 NREL Report[1]. Estimated using USDA Forest Service's Timber Product Output database for 2002, includes logging residues and other removals. |
| Primary Mill Residue (Unused) | 41,000 | 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 | 86,000 | 2005 NREL Report. Includes wood scraps and sawdust from woodworking shops— furniture factories, wood container and pallet mills, and wholesale lumberyards. Estimated using number of businesses from the U.S. Census Bureau, 2002 County Business Patterns and assumptions on the wood waste generated. |
| Urban Wood Waste | 1,196,000 | 2005 NREL Report. Includes MSW wood—wood chips, pallets, and yard waste; utility tree trimming and/or private tree companies; and construction/demolition wood. Data on the collected urban wood waste are not available; thus numerous assumptions were applied for estimation. |

[1] *A Geographic Perspective On The Current Biomass Resource Availability In The United States*, A. Milbrandt, Technical Report NREL/TP-560-39181, December 2005, Prepared under Task No. HY55.2200.

| Biomass Resource | Annual Biomass Supply (dry tons) | Notes |
|---|---|---|
| Agricultural Residue | 3,586,000 | 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. |
| Switchgrass | | 2005 NREL Report estimates a potential 1,451,000 dry tons per year of switchgrass could be grown on CRP lands. |
| Willow or Hybrid Poplar | | 2005 NREL Report estimates a potential 1,410,000 dry tons per year of willow or hybrid poplar could be grown on CRP lands. |
| Poultry Litter | TBD | |
| Municipal Solid Waste (MSW) Fiber | TBD | |
| Wood Pulp | TBD | |
| Yard & Landscape Waste Debris | TBD | |
| **Total Annual Biomass Supply** | **6,184,000** | |

### Land Value and Conservation Easement Costs

The AFW options assume Conservation Reserve Program (CRP) annual payments as a proxy for easement costs.

Total continuous CRP land annual payments for Michigan were $117.50 per acre as of March 2008. This payment includes annual incentive and maintenance allowance payments, but not one-time signing and practice incentive payments or payment reductions, such as for lands enrolled less than a full year and lands hayed or grazed (see http://www.fsa.usda.gov/Internet/FSA_File/mar2008.pdf).

### Land Use

The reduction in fossil diesel fuel use from the adoption of alternative land use or practices is 3.5 gallons/acre.[2] The life-cycle fossil diesel GHG emission factor is 12.31 $MtCO_2e$/1,000 gallons.[3]

[2] Reduction associated with conservation tillage compared with conventional tillage, at http://www.ctic.purdue.edu/Core4/CT/CRM/Benefits.html, accessed August 2006.

[3] Life-cycle emissions factor for fossil diesel from J. Hill et al., "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences*, 103(30):11206–11210. From the assessment used to evaluate U.S. soybean-based biodiesel life-cycle impacts. See http://www.pnas.org/cgi/content/full/103/30/11099

### Fertilizer

The following fertilizer cost information is taken from U.S. Department of Agriculture, Economic Research Service's U.S. fertilizer use and price information (see http://www.ers.usda.gov/Data/fertilizeruse/).

| Month/Year | Average U.S. farm prices of selected fertilizers | | | | | |
|---|---|---|---|---|---|---|
| | Anhydrous ammonia | Nitrogen solutions 30% | Urea 45-46% nitrogen | Ammonium nitrate | Sulfate of ammonium | Average |
| Apr 2007 | 523 | 277 | 453 | 382 | 288 | 385 |

The avoided life cycle GHG emissions (i.e. emissions associated with the production, transport, and energy consumption during application) were taken from Wood and Cowie[4]. The estimate provided for the U.S. (taken from West and Marland, 2001[5]) was 857.5 grams (g) $CO_2$e per kilogram of nitrogen (kgN)[6] or 0.778 $MtCO_2$e per ton of nitrogen (tN). This estimate was significantly lower than the estimates for European fertilizers (ranging from 5,339.9 to 7,615.9 $gCO_2$e/kgN). Wood and Cowie recognize that the estimate for the U.S. is low and suggested that part of this discrepancy could be explained by the exclusion of $N_2O$ emissions from the US estimate, which are significant component of GHG emissions.

### Renewable mix

The table below from the MI Forecast shows the expected mix of total Michigan electricity generation through 2025, as well as the mix if renewable generation. This assumption will help inform the potential mix of technologies deployed on farms to meet renewable energy requirements under AFW-7. eg: 75% wind, 20% biomass, etc.

| Fuel Type | 1990 | 1995 | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 |
|---|---|---|---|---|---|---|---|---|
| **Electricity - Production Based** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |
| Coal | 98% | 97% | 95% | 95% | 94% | 94% | 93% | 93% |
| Nuclear | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Natural Gas | 1% | 1% | 3% | 3% | 4% | 4% | 5% | 5% |
| Oil | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| MSW | 0.1% | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% |
| Biomass | 0.0% | 0.0% | 0.0% | 0.0% | 0.3% | 0.3% | 0.4% | 0.5% |

4 Sam Wood and Annette Cowie (2004) *A Review of Greenhouse Gas Emission Factors for Fertiliser Production* Research and Development Division, State Forests of New South Wales, Cooperative Research Centre for Greenhouse Accounting.

5 West, T. O. and Marland, G. 2001. *A Synthesis of Carbon Sequestration, Carbon Emissions and Net Carbon Flux in Agriculture: Comparing Tillage Practices in the United States.* Agriculture, Ecosystems and Environment 1812, 1-16.

6 These emission factors provide an estimate of the typical life cycle GHG emissions (including resource extraction, the transport of raw materials and products, and the fertilizer production processes) per unit weight of fertilizer produced (i.e., $gCO_2$e/kg fertilizer).

| **Fuel Type** | **1990** | **1995** | **2000** | **2005** | **2010** | **2015** | **2020** | **2025** |
|---|---|---|---|---|---|---|---|---|
| Landfill Gas (LFG) | 0.1% | 0.3% | 0.3% | 0.5% | 0.6% | 0.6% | 0.7% | 0.7% |
| Wind | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Hydroelectric | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Pumped Storage | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Electricity - Renewable Production Only** | **0.2%** | **0.6%** | **0.6%** | **0.7%** | **1.1%** | **1.1%** | **1.3%** | **1.4%** |
| MSW | 47% | 47% | 48% | 30% | 19% | 17% | 15% | 14% |
| Biomass | 7% | 8% | 7% | 6% | 30% | 30% | 30% | 36% |
| Landfill Gas (LFG) | 47% | 45% | 45% | 64% | 51% | 53% | 55% | 50% |
| Wind | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Hydroelectric | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Pumped Storage | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

### Emission Factors

Standard emissions factors for fuel feedstocks are calculated from the Michigan GHG Emissions Inventory and summarized below (note that these emission factors include CH4 and N2O emissions in addition to $CO_2$ emissions).

| **Steam Plants** | | | |
|---|---|---|---|
| **Fuel** | **Fuel use (Billion Btu)** | **Emissions (MMtCO2e)** | **Emission Factor (tCO2e/MMBtu)** |
| Non-lignite coal | 713,765 | 67.74 | 0.095 |
| Lignite coal | 0 | 0.00 | 0.000 |
| Natural Gas | 15,594 | 0.84 | 0.054 |
| Residual oil | 6,926 | 0.54 | 0.078 |
| Diesel oil | 1,446 | 0.11 | 0.076 |
| Petroleum coke | 87 | 0.01 | 0.115 |
| LFG | 0 | 0.00 | 0.000 |
| Refuse derived fuel/MSW | 0 | 0.00 | 0.000 |
| Biomass | 15,366 | 0.03 | 0.002 |
| Nuclear | 179,908 | 0.00 | 0.000 |
| Tire-derived Fuels | 1,843 | 0.16 | 0.087 |
| **Turbines** | | | |
| **Fuel** | **Fuel use (Billion Btu)** | **Emissions (MMtCO2e)** | **Emission Factor (tCO2e/MMBtu)** |
| Natural Gas | 14,693 | 0.79 | 0.054 |
| Diesel | 589 | 0.04 | 0.068 |
| Landfill Gas | 393 | 0.02 | 0.051 |
| Waste oils/solvents | 0 | 0.00 | 0.000 |

| Fuel | Fuel use (Billion Btu) | Emissions (MMtCO2e) | Emission Factor (tCO2e/MMBtu) |
|---|---|---|---|
| **Combined Cycle** | | | |
| Natural Gas | 13,727 | 0.74 | 0.054 |
| Diesel | 0 | 0.00 | 0.000 |
| Landfill Gas | 1,333 | 0.07 | 0.053 |
| **Engines** | | | |
| **Fuel** | **Fuel use (Billion Btu)** | **Emissions (MMtCO2e)** | **Emission Factor (tCO2e/MMBtu)** |
| Natural Gas | 124 | 0.01 | 0.081 |
| Diesel | 128 | 0.01 | 0.078 |
| Landfill Gas | 4,553 | 0.24 | 0.053 |
| LPG | 0 | 0.00 | 0.000 |
| Residual Oil | 3 | 0.00 | 0.000 |
| **Renewable** | | | |
| **Fuel** | **Fuel use (Billion Btu)** | **Emissions (MMtCO2e)** | **Emission Factor (tCO2e/MMBtu)** |
| Wind | 18 | 0.00 | 0.000 |
| Solar PV | 0 | 0.00 | 0.000 |
| Hydroelectric | 14,616 | 0.00 | 0.000 |
| ***Total*** | **985,111** | **71.36** | **0.072** |

The emissions factor for grid electricity was also taken from the Michigan inventory and forecast, derived by dividing total electricity consumption emissions in 2005 by electricity sales in 2005. This provided an Electricity Emissions Factor of 1.317 Metric Tons $CO_2$e per MWh.

### Fuel Prices

The following table shows fuel prices for delivered costs in the East Central Area Reliability Coordination Agreement region from the *AEO* 2007. The NEMS model has been criticized for its forecasts "mean reverting", or underestimating sustained fuel price increases and declines.[7] 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.

**Delivered Fuel Price (2005 dollars per million Btu)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 1.51 | 1.69 | 1.69 | 1.84 | 1.87 | 1.86 | 1.89 | 1.87 | 1.85 | 1.84 | 1.83 | 1.82 | 1.80 | 1.81 | 1.77 | 1.76 | 1.73 | 1.73 | 1.74 |

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

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas | 6.66 | 6.28 | 5.70 | 5.39 | 4.98 | 4.83 | 4.64 | 4.68 | 4.63 | 4.74 | 4.94 | 4.89 | 4.88 | 5.02 | 4.97 | 5.12 | 5.26 | 5.34 | 5.30 |
| Distillate Fuel Oil | 15.93 | 14.38 | 13.22 | 12.12 | 10.98 | 9.99 | 9.13 | 9.02 | 9.09 | 9.11 | 9.25 | 9.34 | 9.56 | 9.67 | 9.78 | 9.95 | 9.93 | 10.09 | 10.12 |
| Residual Fuel Oil | 8.23 | 7.65 | 7.05 | 6.55 | 6.16 | 5.83 | 5.67 | 5.51 | 5.57 | 5.57 | 5.70 | 5.73 | 5.92 | 5.98 | 6.09 | 6.22 | 6.16 | 6.29 | 6.31 |
| Biomass | 1.61 | 1.65 | 1.87 | 1.86 | 1.81 | 1.80 | 1.77 | 1.77 | 1.89 | 1.88 | 2.03 | 2.10 | 2.04 | 1.99 | 1.91 | 1.95 | 2.10 | 2.16 | 2.16 |

Assumed cost of electricity is based on Future East Central Area Reliability Coordination Agreement prices from the EIA Annual Energy Outlook (see http://www.eia.doe.gov/oiaf/aeo/supplement/index.html), illustrated below:

| East Central area Reliability Coordination Agreement - 01 | |
|---|---|
| Year | All Sector Average Electricity Price **(2005$** per kWh) |
| 2008 | 0.077 |
| 2009 | 0.076 |
| 2010 | 0.075 |
| 2011 | 0.073 |
| 2012 | 0.071 |
| 2013 | 0.071 |
| 2014 | 0.071 |
| 2015 | 0.071 |
| 2016 | 0.072 |
| 2017 | 0.073 |
| 2018 | 0.074 |
| 2019 | 0.075 |
| 2020 | 0.075 |
| 2021 | 0.076 |
| 2022 | 0.075 |
| 2023 | 0.076 |
| 2024 | 0.076 |
| 2025 | 0.076 |

## Capital costs and capacity factors

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, MI 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 | | 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/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Project Contingency Factor | Technological Optimism Factor[2] | | | | | |
| 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.[8]

### 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 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.

### Biofuels

*Fuel Life-Cycle Emission Factors*

The fuel life-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 life-cycle emission factor for gasoline is 11.3 metric tons $CO_2$e/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 metric tons $CO_2$e/1,000 gallons.

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

The life-cycle emission factor for 100% corn ethanol is 9.1 metric tons $CO_2$e/1,000 gallons. This value includes 195 g $CO_2$e /bushel emissions for land use change due to corn farming.

The life-cycle emission factor for cellulosic ethanol is 1.51 metric tons $CO_2$e/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 life-cycle emission factor for soybean-based biodiesel is 0.667 metric tons $CO_2$e/1,000 gallons.

*Carbon emissions from land use change*

Recent publications such as Searchinger, et al., 2008 (Searchinger et al., *Sciencexpress,* "Use of U.S. Croplands for Biofuels Increases Greenhouse Gases through Emissions from Land Use Change," February 7, 2008), 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 market and drive grassland or forest conversion to cropland in other parts of the world. There is still significant uncertainty regarding the value of carbon emissions due to land use change so at this juncture emissions from land use change are not incorporated into the quantification except those already included in the GREET model.