Paper #2-28

ENVIRONMENTAL FOOTPRINT ANALYSIS FRAMEWORK

Prepared for the Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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EXCUTIVE SUMMARY

All energy source developments can cause positive and negative environmental and community impacts. Those impacts can be categorized as affecting air, water, land, livestock, wildlife and habitat, visibility, and the community or quality of life resources. Combined effects of environmental impacts are defined as the environmental footprint (EF) which, for an energy development, can be addressed as a primary life-cycle assessment (LCA) of the energy source impacts from its production to its end use.

An equitable definition and comparative analysis of the EF for each of the energy options requires a complex methodology that must include: (a) A scalability filter to avoid making comparisons that are inappropriate; (b) A primary life-cycle approach that defines factors to be included and those that are excluded; (c) Consistent and compatible metrics to facilitate comparative analyses including risk so that both probable and consequential impacts are assessed; (d) Recognition that not all criteria for comparison are quantitative and that qualitative or semi-quantitative data must be analyzed in some cases; (e) An assumption that energy development is performed in substantial compliance with applicable environmental regulations; (f) An accounting for unique situational or locational factors; (g) The temporal nature of the impacts.

EF calculations are illustrated by comparison of LCA impacts for natural gas and wind as two different energy sources for electric-power generation. In addition, natural gas and biodiesel are compared as motor vehicle fuels. The principal impacts considered are surface (land use), air and water and the applicable metrics are for impacts per 1,000 megawatt-hours (MWh) of new electric-power generation or for impacts per 15,000 miles driven annually, as appropriate for the end use of the energy source. The LCA includes production of the energy source in the field, refining into a condition where it is ready for end use and, in the case of electric-power generation, the effects of the power plant. Comparative EF results are as follows:

End Use of Energy Source	Environmental Impact (Primary LCA)	Natural Gas EF	Biodiesel EF	Wind EF
Electric-Power Generation (1,000 MW of new capacity added to the grid)	Surface (Land Use)	702 acres	Not Applicable	1,943 acres
	Greenhouse Gas Emissions	814 tons CO2e	Not Applicable	335 tons CO2e
	Water (Consumption)	112,700 gallons	Not Applicable	Not Applicable
Transportation (per 15,000 miles driven by a Light-Duty Vehicle)	Surface (Land Use)	31 sq. feet (< 0.00076 acres)	274,428 sq. ft. (6.30 acres)	Not Applicable
	Air (Gas Emissions)	~12.75 lbs. NOx ~5.25 tons CO2e	~202 lbs. NOx ~4.93 tons CO2e	Not Applicable
	Water (Consumption)	258 gallons	120,000 gal	Not Applicable

Natural gas from shale has a lower surface (permanent disturbed land) impact than either wind power (electricity) or biodiesel (transportation fuel). For electric-power generation (1,000 MWh of new capacity added to the grid), the EF for natural gas with a 42 percent capacity factor includes 238 acres of well pads, 71 acres for gas processing and 393 acres for gas-fired power plants. The power-generation EF for wind involves a surface impact of 1,943acres (turbines and infrastructure only); the reduced nameplate capacity factor for wind turbines and the typical buffer zones associated with wind projects might increase the actual land (wind farm boundary) required to 102,000 acres or more. For transportation (15,000 miles driven), the EF for natural gas includes 1.2 acre for a single well and 0.37 acre for gas processing of that well, the combined attributes of which are sufficient to supply fuel to 2,228 light-duty vehicles or 31 square feet per vehicle, less surface area then is required to park the car. The EF for performance of biodiesel for one automobile includes 6.3 acres for soybean production and 0.0043 acres for refining thus 14,037 acres would be disturbed to power the equivalent 2,228 LDV.

For electric-power generation, additional water is used for cooling during fuel combustion and conversion although the volume depends on whether the power plant uses an open- or closed-loop cooling system (approximately 112 gal/MWh for a closed-loop system). As a transportation fuel, natural gas has substantially-reduced water impact because the rate of gas consumption is less than for power generation. For biodiesel manufactured from irrigated soybeans, the average water consumption is 800 gallons for every 100 miles traveled.

Air impacts involve more variables than some other potential impacts because emissions include listed (regulated) chemical and particulate-matter pollutants and greenhouse gases (GHGs, as equivalent carbon dioxide (CO2e). Although emissions from combustion of natural gas and biodiesel are more obvious, air emissions from wind power result from onsite construction of infrastructure needed to support turbines plus annual maintenance of those facilities.

In developing the EF examples, numerous deficiencies in data became apparent. First, it was found that much of the information and data needed for an EF analysis may exist, but not in the form required or in forms that are not easily accessible. Second, most attempts at EF analysis did not include risk-assessment scores as indicators of the likelihood of future environmental catastrophes involving individual energy sources. Finally, none of the examples of EF analysis included criteria for peer review of the outcomes.

Although the EF results are informative and instructive, it is recognized that they are limited to quantitative data and environmental impacts. Challenges remain for including qualitative data and community impacts. To provide for EF LCA inputs that are essential in making decisions that affect the future energy mix of North America, it is recommended that:

- The US Department of Energy (DOE), in consultation with other agencies, should develop a methodology for comparing the EFs of various energy sources, using a public process with input from all interested stakeholder groups.

- DOE should assess the availability of information and data needed to implement the EF methodology and fund and manage a program to collect and analyze the necessary data.

DOE should publish and regularly update a LCA of the EF of the energy sources expected to make a weighty contribution to the future North American energy economy, including the types of impacts listed above, taking into account variations by resource type and location, and discussing the uncertainties in the analysis.

INTRODUCTION

As the North American economy evolves in the coming decades, a host of decision makers will be determining the structure of the future energy economy. Thousands of such decisions are made every year regarding capital investments, research and development (R&D) expenditures, policy priorities, legislation, and regulatory requirements. Those energy-related decisions will result in the energy sources that will be used, both explicitly – namely, a decision on which energy source to use to generate electric power – and implicitly – that is, how a law or regulation will influence energy choices. While economics ultimately drives most energy decisions, the environmental implications of the decisions are becoming increasingly important. Environmental matters can affect operation economics, influence the vision of public and policy makers on energy production, require increased protective standards, enhance understanding of potential consequences, and delay or even halt projects. Environmental matters related to energy development and generation includes both adverse and beneficial effects to air, water, land, community, and quality of life resources. Those items classified as environmental matters are also intrinsically linked to operational matters – in how the issue is caused by an operation and how it might be resolved by a change in operations. Energy choices can have both negative and positive impacts on the environment at global, national, regional, state, and local levels.

Decisions about environmental matters potentially can affect energy projects in several ways:

- Increasing the cost of a project due to compliance requirements and accounting for the negative environmental externalities not yet priced in the energy source.
- Improving air and water quality by establishing pollutant emission and discharge standards.
- Restricting access to energy resources, through permit moratoria, land use restrictions, and timing restrictions on development activities.
- Reducing greenhouse gas emissions by heightening awareness to global climate change.
- Increasing efficiencies, recycling, conservation, and designing criteria for more sustainable generation, extraction, and transportation methods.
- Requiring permits and environmental impact statements for projects so that informed decisions are made.
- Increased recycling, treatment, conservation, and beneficial use of water in all life-cycle phases.

- Influencing policies that affect the ability to locate and operate energy projects, and tilt energy source decisions.
- Affecting the "social license" of and perception about the domestic energy industry.
- Markets accounting for the above factors and developing appropriate valuations and/or responses.

Therefore, it is important that those making energy source decisions reflect science-based, consistent, comparative information on the environmental impacts of each energy resource, otherwise known as the environmental footprint (EF).

The environmental footprint is used herein as the cradle-to-grave cumulative sum of incremental positive and negative environmental impacts of the process of developing, processing, transporting, and using an energy resource. A cradle-to-grave assessment considers the entire life cycle of a product or, in this case, an energy source; therefore it can be assessed following principles developed for life cycle assessments (LCA). LCA evaluates all stages of an energy source's life from the viewpoint that they are sequential and interdependent. LCA facilitates the appraisal of cumulative environmental impacts accruing during all stages in the energy source life cycle, capturing impacts not contemplated in more established examinations (e.g., raw material extraction, material transportation, material processing, ultimate material use, etc.) (SAIC, 2006). An LCA must assess each natural medium (air, water, and land) and resource inputs (energy, water, and other resources). It is challenging to combine the LCA for each medium and resource into a single environmental footprint (EF) analysis for each unique area. Decisions are needed on how to balance and compare the various impacts (i.e., is water use valued at a higher level than air emissions?). There are not strong methodologies for how to make an overall EF for energy sources across all media and all resource use.

To be of greatest value, the EF analysis would present impacts in a common set of metrics, under a series of main categories, such as resource consumption, land utilization, discharges (air & water), risk assessment, toxic potency, and energy expenditure. The decision makers will then have information to weigh against social factors such as job creation, job retention, national security, energy independence, wealth exportation, resource depletion, and other considerations to select the energy resource appropriate for the specific circumstance and national, regional and local priorities. An objective understanding of impacts will enhance the decision-making process.

This paper provides: 1) an EF analysis and LCA framework; 2) existing information on environmental impacts per energy resource; 3) the quantitative and qualitative consideration to develop comparable measurements of impact, uncertainties, and data complexities and gaps; 4) examples of calculations; and 5) recommendations on how to develop an EF analysis for energy sources.

The value of conducting an EF analysis includes support for planning and could be done in a transparent fashion involving interested stakeholders. That approach can increase an understanding of the issues and institutionalize an objective analysis in public and private decision making. A recent National Research Council (NRC) study entitled, "Hidden Cost of Energy: Unpriced Consequences of Energy Production and Use", specifically reports findings about health and environmental externalities from various energy types and calls for a life-cycle analysis of full fuel cycles (NRC, 2009). Additionally, an independent research study issued by the Applied Energy Studies Foundation titled "The Environmental Cost of Energy" identified the need for further in-depth analysis of environmental implications associated with the development of various renewable and nonrenewable energy source (AESF, 2010).

ENERGY SOURCE IMPACTS

A. Environmental Impacts

All energy source developments can cause positive and negative environmental and community impacts. Those impacts can be categorized as affecting air, water, land, livestock, wildlife and habitat, visibility, and the community or quality of life resources. The following sections briefly examine the potential impacts from the development and use of various energy resources.

(1) Impacts to Air

Air quality impacts include adverse influences to human health, livestock, wildlife, vegetation, and visibility. The US Environmental Protection Agency (EPA) holds authority over air quality through the Clean Air Act (CAA). Air pollution can affect human health, wildlife, and vegetation in different ways depending on the age and general health of the exposed humans, animals or plants, the type of pollutant, and amount or length of exposure. Air pollution impacts can be local (facility level) or regional (ozone, acid rain, or visibility impairment). Most sources of energy development emissions are from support activities that are needed to produce the resources plus the actually end-use of those resources (GWPC-ALL, 2009; IOGCC-ALL, 2008), including the following:

- Construction and mobile sources, including light duty vehicles, equipment and traffic (primarily dust and volatile organic compounds [VOCs]);
- Combustion and production operations, including flaring of excess natural gas at oil or gas well sites and processing facilities and production, storage, and processing equipment (criteria air pollutants, hazardous air pollutants [HAPs], and greenhouse gases [GHGs]);
- Burning fossil fuels at industrial, commercial and residential locations for energy, heat, cooking, or cooling (criteria air pollutants HAPs, VOCs, and GHGs); and
- Power plant stacks and cooling towers (steam, mercury, and heat).

Surface deposition of certain air pollutants will have adverse impacts to water bodies, sediments and soils. Greenhouse gas (GHG) emissions are the subject of ongoing scrutiny due to their potential contribution to climate change (Houghton et al., 2001).

(2) Impacts to Water

Impacts to water resources can result in quantitative and qualitative consequences for surface water and / or groundwater (GWPC-ALL, 2009; IOGCC-ALL, 2008):

- Water withdrawals can result in the
  - Reduction of surface water or stream flow, or decrease of groundwater levels in aquifers. Those flow reductions can cause adverse changes to aquatic habitats and species and negatively affect downstream and groundwater availability.
  - Impacts to water quality by discharges of various waste streams or from diversion returns, which can either increase or reduce water availability and alter quality depending on the assimilative capacity of the waters that receive the discharges.
  - Redistribution of water resources by withdrawing groundwater or surface water from one locale and subsequently discharging it elsewhere, including into a surface water body or subsurface disposal zone.
- Water consumption can result in the
  - Degradation of water quality by creating a loss of water of some initial quality through either direct or indirect activities (i.e., using freshwater for drilling fluids for oil, natural gas and geothermal wells).
  - Reduction or loss of available water by placing water into different areas within or external to the hydrologic cycle, including waste water disposal in underground injection control wells and water loss through evaporation (i.e., cooling towers at power plants).
- Water quality can be affected by
  - Chemical or physical interactions that change water quality, including mixing freshwater with process waters in mining operations or water contacting natural earthen materials or process chemicals during production of the energy resource.
  - Direct or indirect discharges of contaminants into water bodies, including permitted waste waters with elevated levels of contaminants, different pH values or temperatures relative to the receiving waters.
  - Construction and land clearing activities that result in increased erosion and storm water runoff which can increase the sediment load in surface water bodies.
  - Spills and leaks of chemicals and toxic materials used for the production of energy or created as a byproduct of energy production causing contamination of surface or subsurface water bodies.

(3) Impacts to the Land and Wildlife

Impacts to land include surface disturbance and soil quality. Sources and types of land impacts may result from the construction or use of infrastructure (GWPC-ALL, 2009; IOGCC-ALL, 2008) that includes:

- Roads, seismic exploration, utility corridors (to import energy and water into the site), pipelines and transmission lines (to export energy and water away from the site), water and waste water impoundments, energy generation sites, and facilities for oil and natural gas processing and distribution.

- Mine shaft entrances for subsurface mines, the removal of large areas of overburden for surface mines and the ancillary roads and surface facilities that support mines.

- Dams for hydroelectric projects disturbing the surface for the dam and associated generating facilities (not always contiguous) and land flooded by the upstream reservoir.

- Land for the growth and harvest of biofuel feedstocks (e.g., corn for ethanol, soy for biodiesel, biomass for biodiesel), causing soil erosion from land disturbance, irrigation, and runoff, and sedimentation in surface waters (streams, rivers, lakes, seas and oceans).

Surface disturbances are often minimized through interim and final reclamation activities.

Soil quality may be impacted by the intentional or unintentional release of chemicals (fuels, oils, fertilizer, herbicides, pesticides, etc.) or waste materials (cuttings, drilling muds, sludge, mine tailings, fly ash, wastewater, etc.) to land.

Surface activities can affect aquatic and terrestrial habitat and wildlife behavior (IOGCC-ALL, 2008) that includes:

- Disturbance to land and habitat, resulting in loss, fragmentation, and alteration (increased predation, invasive plant species) from activities necessary for energy resource extraction, production, processing and generation (including right-of-way corridors, power lines, pipelines, drill rigs, truck traffic, wind turbine erection, solar array clearing, surface mining, etc.).

- Increase in noise disturbance from construction and operation activities, which can impact wildlife over the short and long terms based on the level, frequency, and duration, depending on species sensitivity.

- Quantitative and qualitative changes in water resources can negatively (reduce water quality or quantity) and at times positively (habitat creation via lakes, ponds or engineered wetlands) affect wildlife (Illinois DNR, 2011).

(4) Community Impacts

Noise can affect both human health and quality of life. Causes of noise (IOGCC-ALL, 2008) include:

- The construction of energy-related equipment and facilities, where the duration is based on the size of the project (i.e., typically shorter than operational noises) and varies by work hours and timing of the activities.
- Operation activities which can vary considerably and affect the quality of life for nearby residents or recreational users to various degrees (i.e., man-made sounds like sirens and horns, traffic, equipment or engines and low-frequency sounds from wind turbines).

Impacts to the viewshed of landscapes (IOGCC-ALL, 2008) include:

- The skyline through placement of energy development infrastructure and equipment, which can be long-term (wind farm, cooling tower, tanks, or high voltage transmission line) or short-term (construction cranes and drilling rigs).
- Alteration of viewsheds, which includes construction and alteration of the land changing the viewshed (i.e., dams, high voltage transmission lines, pipeline corridors, or the placement of equipment and infrastructure associated with development of energy resources).
- Visibility impairment caused by air pollution.

Impacts resulting from traffic (GWPC-ALL, 2009; IOGCC-ALL, 2008) include:

- Changes to local traffic patterns by the creation of additional traffic flow, increase in or creation of new traffic burdens, increase in accidents and other incidents (increasing the burden on law enforcement).
- Increased burden on transportation infrastructure, including roadways, highways, bridges, and railroads, which is related to the level of energy resource development and level of heavy truck traffic that may exceed design standards for roadways and bridges, creating additional burdens on county or state funds to provide repairs.

Other impacts to community and quality of life (IOGCC-ALL, 2008) include:

- Installation of infrastructure that changes existing land use and could increase access to and use of land that can result in trespass or access to private areas.
- An increase in tax revenue and demand for local businesses, changes in property values and the job market, increased living expenses and reduced access to local equipment, and other materials associated with construction and development.

- Increased burdens on public services such as schools, social services, courts, police and fire, hospitals, and changes in the character of the community (Clougherty, 2010).

- Possible human health impacts (for certain of the previously mentioned environmental impacts). Contaminated air, water, and land can have physical health impacts, noise can cause health changes, and increased traffic accidents cause minor to fatal injuries (Witter et al., 2010). Social stressors and the stress associated with fear of exposure to unknown substances can have a range of negative physical and mental health effects. Evidence suggests that chronic stress can also increase susceptibility to other forms of pollution.

B. Energy Source Profiles

Environmental impacts associated with energy development are often viewed as negative; however, modern energy systems do not necessarily have an unfavorable impact on society. In fact the opposite is true and the advantages to civilization from energy systems have been immense. As these energy systems have matured, energy developers have recognized the need to protect the environment and have made considerable advances over the decades to reduce environmental effects. Those advances have been achieved through both technological innovations and public concerns leading to regulatory policy and requirements. The relentless market pressures to supply energy cheaper, faster, and better, coupled with a growing awareness of our interconnected environment, have resulted in numerous improvements and efficiencies that both protect the environment and enhance energy delivery. That ongoing parallel track is expected to continue and promises to deliver environmental sustainability while realizing cost-effective energy supplies.

Table 1 summarizes common environmental impacts for various key energy types which would be part of an environmental footprint analysis. General descriptions of potential environmental impacts associated with each energy source are included in **Appendix A.**

Table 1. Common Environmental Impacts by Energy Type.

Energy Source	Key Types of Impacts	Areas of Public Interest
Natural gas	Surface footprint (onshore and offshore), surface water from runoff, water use, air emissions, waste generation, exemptions, human health, water impacts, GHGs, wildlife habitat, aquifer drainage	Hydraulic fracturing
Oil	Surface footprint (onshore and offshore), surface water from runoff, water use, air emissions, waste generation, fish habitat, exemptions, human health, GHGs, aquatic ecosystem spills, wildlife habitat	Offshore spills
Coal	Surface footprint, surface water from runoff, water use, mountaintops, air emissions, waste generation, GHGs, aquatic habitat, topography, recreational areas	Climate change, mountain top mining
Oil Shale	Surface footprint, surface water from runoff, water use, air emissions, waste generation, GHGs, wildlife habitat, aquatic ecosystems	Energy and water use
Nuclear	Radioactive waste generation/storage, uranium mining necessary for feedstock, radioactivity releases, human health	Waste disposal, public safety
Solar	Surface footprint, waste generation, water use, hazardous material	Chemicals used in

Energy Source	Key Types of Impacts	Areas of Public Interest
	disposal, wildlife habitat,	processing
Wind	Surface footprint (onshore and offshore), surface water from runoff, water use, air emissions, waste generation, wildlife habitat, noise, visual, avian & bat deaths, marine mammals	Visual, noise, health, birds / bat deaths
Geothermal	Surface footprint, sensitive environments, wastes, water quality, wildlife habitat, subsidence	Availability
Hydroelectric	Habitat disturbance, river system changes, land inundation, aquatic ecosystems, fisheries,	Aquatic wildlife and habitat impacts
Biofuels / Biomass	Surface footprint, surface water from runoff, soils, aquatic systems, water use, carbon balance, air emissions, GHGs, waste generation, wildlife habitat, human food chain	Social, energy requirement

METHODOLOGY: LAYING THE FRAMEWORK FOR COMPARATIVE ANALYSIS

The "environmental footprint" analysis, coupled with the LCA used in this section, refers to the cradle-to-grave cumulative impact of incremental environmental impacts (both beneficial and adverse) that occur throughout the entire process of developing and using a given energy source. A consistent methodology is key to equitably comparing the environmental footprint of energy types. Several terms are used to define the effective comparative evaluation of the most relevant issues and allow the less relevant or quantifiable issues to be outside of evaluation. These fundamental considerations include:

- Scalability.
- Metrics.
- Regulatory compliance.
- Unique considerations.

The LCA approach outlined herein relies on the use of appropriate boundaries and metrics for each energy source and impact type as described in the following subsections.

A. Life Cycle Assessment

LCA identifies the framework by which the evaluation of cradle-to-grave direct and cumulative environmental impacts for a given set of resources may be performed consistently under the "environmental footprint" analysis for various energy sources. Metrics of impacts to multiple resources can be combined into a holistic picture of the "environmental footprint" of any energy source type. The environmental footprint can be defined as the breadth of incremental impacts necessary to adequately compare the footprint of source types (SAIC, 2006). Policy makers can use such analyses to weigh the impacts and benefits of various energy sources in developing national, regional and local energy policy.

For instance, policy makers may wish to evaluate the sensibility of requiring that by a specified date 20 percent of the nation's electrical needs must be provided by wind power. To evaluate the environmental consequences of such a decision, an LCA can be used to compare the environmental footprint of the necessary amount of wind power and other energy sources. The increase in the desired power type could then be evaluated to predict the likely environmental consequence of the contemplated development versus that of an alternative energy source or of existing power generation (i.e., the status quo).

An LCA for energy (SAIC, 2006) can include, but is not limited to, an examination of:

- Extraction of the raw resource, including:
    - Drilling oil or natural gas wells and transportation to a processing facility or the end user.
    - Mining of coal or uranium and transportation to a processing facility.
    - Constructing a solar or wind farm and transmission to the end user.
    - Farming of biofuels feedstocks (e.g., algae, corn, soy, switch grass, wood) and transportation to the end user.
- Processing, manufacturing, and conversion, including:
    - Ethanol from corn.
    - Biodiesel from soy.
    - Uranium ore into fuel rods.
    - Oil or natural gas into commercial fuels.
- Energy end use, re-use, and maintenance, including use of:
    - Coal to generate electricity and transmission of electric-power to the end user.
    - Natural gas to generate electricity and transmission of electric-power to the end user.
    - Nuclear fuel to generate electricity and transmission of electric-power to the end user.
    - Biodiesel or compressed natural gas to power vehicles.
    - Petroleum-derived gasoline or diesel to power vehicles.

- Electricity to power vehicles.

- Management of emissions, effluent, and waste, including:

Produced water and hydraulic fracture produced water from oil or gas drilling and production.

- Spent nuclear fuel wastes.
- Spent semi-conductor solar panels.
- Spent lubricating and cooling oils from wind turbines.
- Mine tails and spoils.

In developing an LCA, the following boundaries must be chosen: 1) baseline year; and 2) level of comprehensiveness to adequately define a life cycle. The baseline year can be established based upon the validity of the historical data. The appropriate level of detail could include the primary life-cycle parameters including the energy necessary to drill the well or mine the coal. A primary life-cycle parameter is the "sequence of activities [that] directly contributes to making, using, or disposing of the product or material" (SAIC, 2006). The primary assessment includes an evaluation of the environmental impacts from extraction to final end use, including processing, transportation, distribution, and waste streams generated along the way.

Secondary life-cycle parameters include activities such as the manufacture of the blades for a wind turbine, the manufacture of the drilling rig for a natural gas well, or the manufacture of semi-conductor panels for a solar farm (SAIC, 2006). Performing a secondary life-cycle assessment can be extremely complex. Deciding which factors to include or exclude may be subjective and difficult to apply consistently across energy sources.

A primary LCA is the most realistic approach for obtaining a comparable assessment level. Figure 1 presents process-based primary LCA of energy resources, including inputs (raw materials, energy, and water) and outputs (air emissions, water discharges, surface impacts, biological changes and noise and visual impacts). Each energy source must be evaluated to the same level of detail. The policy maker must define and justify the limits of the analysis and assure an appropriate peer review.

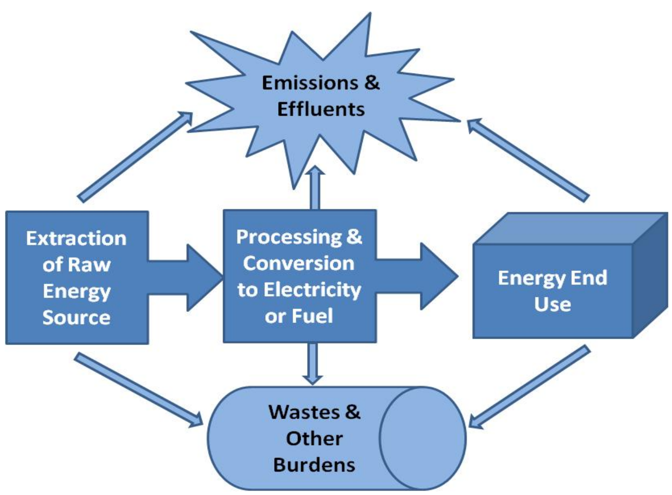


Figure 1. Life Cycle Assessment (NRC, 2009).

B. Scalability

The comparison between energy sources arguably needs to include scalability. Scalability means whether the energy source can meaningfully contribute to the current North American electrical or fuel needs (i.e., grid, industrial combustion, routine daily heating, and transportation). Energy sources that are not yet scalable and only exist in an experimental capacity (e.g., hydrogen cell technology) or are limited to local application (e.g., roof-top solar power) cannot realistically be compared to other scalable sources. It is most appropriate to compare one scalable source to another scalable source and is also potentially misleading. It is less defensible to compare a scalable source to a non-scalable source of energy.

C. Metrics

A consistent, objective and quantitative set of measurements or units (i.e., metrics) is important to ensure an effective comparison of dissimilar energy sources. Most of the energy sources included herein are capable of generating electricity, with the exception of corn-ethanol and biodiesel. Therefore, the unit of 1,000 megawatt-hours (MWh), which is commonly referenced in the electric-power industry, is a useful comparative metric for the performance of fuels in the context of electric-power generation. The impact (e.g., surface disturbance, air emissions, etc.) associated with generating 1,000 MWh from one energy source versus another can be compared using a metric such as acres disturbed per 1,000 MWh generated or tons of CO2 emitted per 1,000 MWh generated. For heating fuels, environmental impacts assessed on a basis of one million British thermal units (MMBtu) basis also would be appropriate. For transportation, assessment units for environmental impacts per mile driven (for example pounds of CO emitted per 100 miles driven) would be appropriate. The use of these assessment units allows for scaling considerations which facilitates the comparison of evolving technologies to existing technologies. Because some renewable sources produce energy in specific forms (e.g., electricity or transportation fuels), comparisons should be made by determining the environmental footprint associated with delivering that form of energy based on its end use.

These calculations could also account for the relative quality of fuels. Different grades of coal will have different Btu contents. Measurements based on heat or electrical power produced account for the thermal or thermal-equivalent energy content of each energy source.

Some impact types cannot easily be quantified and some assessments may be constrained to semi-quantitative or even qualitative terms. That constraint may be especially true for impacts related to quality of life. Not all environmental impacts are similar nor can all environmental impacts readily be placed into quantifiable terms. However, where quantitative assessments are possible, they should be associated with a standard metric, or measure, in order to make valid comparisons.

D. Environmental Regulatory Compliance

Different industries have different compliance requirements and levels of compliance attainment, including different environmental impacts resulting from noncompliance. For purposes of the environmental footprint analysis, an assumption of compliance is essential since it would be difficult to assign a level of non-compliance and then evaluate the environmental impact of those non-compliant activities across the various industries If that reality is to be reflected in the EF analysis, a consistent methodology for including risk must be identified and accepted.

The majority of practices that result in environmental impacts associated with the production and consumption of energy are governed by federal and state laws and regulations that limit the degree or intensity of the impacts and may impose mandatory control or mitigation measures. Oil and natural gas extraction and coal and uranium mining operations are subject to federal, state, and local regulations that are intended to limit the environmental impacts from those activities. The CAA regulates emissions from electrical power generating facilities and industrial manufacturing plants. The Clean Water Act (CWA) and Safe Drinking Water Act (SDWA) address impacts to surface and ground water. Emissions from automobiles and other motor vehicles are regulated at the state and federal levels. These regulations are assumed in the footprint analysis to be effective in achieving their goals of protecting human health and the environment based on the science employed during their development. Since enactment, those regulations and policies have done much to minimize the magnitude of environmental impacts. Including a risk factor in the EF analysis to account for the differences in noncompliance-caused impacts would be helpful for assessing the effect of anthropogenic actions.

E. Unique and Additional Considerations

It is generally recognized that not all energy sources are appropriate in all locations. The sun does not shine with the same reliability in all parts of the world. Likewise, the distribution of consistent, forceful wind is not uniform. Soil type and weather conditions affect areas where biomass plants can be grown under natural conditions. Oil, gas, and coal deposits are only found in certain geographical locations. Those natural variations mean that energy sources may have greater, lesser, or simply different environmental impacts depending upon where that resource is or can be located. Such factors must be considered when comparing different energy sources to each other or in comparing one energy source in different locations. For example, the environmental impacts and concerns of oil drilling in the offshore Arctic are different from those of oil drilling in the offshore Gulf of Mexico. Different land types or locations will have different sensitivities to impacts; for instance, some desert, tundra, and wetland landscapes may be more sensitive to impact and so may require a longer period of time to recover.

Impacts to resources such as fresh water and clear air can also be magnified in high population density areas where the number of receptors is maximized. For instance, changes to air quality may push pollutant levels over critical non-attainment thresholds in areas with high population densities where other anthropogenic impacts already exist. On the other hand, small changes in air quality may be very noticeable in pristine areas such as Class I airsheds.

The temporal nature of impacts should also be considered. Environmental impacts can be short-term, long-term, temporary, or permanent and can vary greatly over time. Temporary visual impacts associated with drilling for natural gas and oil differ from the permanent visual impacts associated with wind farms. The time dimension of changes to the chemistry of the atmosphere from combustion of fossil fuels is also a consideration. Impacts on the global environment that are essentially permanent in the scale of human existence are driving a host of energy policy decisions at the state and federal levels that will have a growing influence on energy choices. Other impacts are reversible or can be remediated. A photovoltaic solar array constructed in an open landscape can easily be reclaimed when the solar array's productive life has ended while the impacts of mountaintop mining are often not reclaimable to pre-existing conditions. The environmental impacts of biofuels and biomass include land use for farming. This requires a continual land disturbance causing loss of soil, surface runoff, sedimentation buildup, and continual chemical use in fertilizers and pesticides. Wind and gas development creates an initial disturbance to the land that may be more permanent (i.e., roads and site construction), but may be partially reclaimed, have a more minor ongoing impact (i.e., traffic), and have limited recurring replacement requirements (i.e., wind turbines).

The nature of the resource being developed and the technology that will be used to develop it must be taken into account when doing EF analysis. Shallow conventional oil and natural gas development involves different drilling and production techniques than the development of unconventional petroleum reservoirs (e.g., coal bed natural gas, shale gas, shale oil); resource extraction methods are different and waste by-products can also differ in both quantity and quality.

Some natural resources can be accessed from remote locations. Oil or gas wells can be drilled directionally to reach reservoirs located under sensitive environments (e.g., wetlands, tundra, lakes, or deserts) or under sensitive locations (e.g., historic landmarks or parklands). Similarly, underground mining can take place beneath areas where direct surface mining may not be acceptable (e.g., under towns and cities).

Energy sources will not be developed if they are not economically practical unless some form of subsidy is attached to their development. Any comparison of resources and exploitation approaches must consider the overall economics, including any required subsidies, for the comparison to be meaningful.

It is evident that unique and sometimes intangible variables must be included in a comprehensive analysis of energy-source alternatives. It is also apparent that in some cases those variables can be defined by quantitative metrics, whereas in other cases qualitative comparison may be the only means possible.

A measurement of environmental consequences should be assessed at a common end point and from a common form, such as assessing the environmental consequences for sources used to generate electricity to the point where the electricity it is ready to be placed on the grid. Understanding of the boundary issues to be included in an analysis is critical to the development of an assessment producing comparable results. This becomes particularly evident when assessing highly dissimilar sources of energy (e.g., concentrated versus dispersed generation and use, direct generation and use versus energy that requires intermediate processing to use). Hence, the varied nature of the resources used to generate energy creates a need to develop common methodologies for assessment.

The level of data detail and quality of the data which can be obtained for analysis may be a limiting factor. Data may be varied or non-existent, depending on the energy source or environmental media being analyzed. Activities associated with the development of non-renewable resources have been studied and assessed in various documents developed by federal agencies such as the Bureau of Land Management (BLM) and US Forest Service. Such assessments do not appear to be available for other resources or for all of the impacts of interest.

Data exist regarding environmental impacts for specific locations in which resource development is occurring. The data are maintained by a variety of regulatory authorities and for various purposes but those data cannot always be applied or extrapolated to other locations. For instance, assessments of environment impacts for development of oil and natural gas resources in the Rocky Mountain Front region of the US would not necessarily be applicable to the Gulf Coast region. Data sources also can become outdated due to changing technologies, resources, and regulations. Each of those data-related factors will influence the level of detail possible for a data-driven assessment.

F. Methodology: Summary

The process leading to an equitable definition and comparative analysis of the EF for each of the energy options requires a highly complex methodology that must include:

- A scalability filter to avoid making comparisons that are inappropriate.
- A primary life-cycle approach to defining the limits of factors to be included and those that are excluded.
- Consistent and compatible metrics to facilitate comparative analyses including risk so that both probable and consequential impacts are assessed.
- Recognition that not all criteria for comparison are quantitative and that qualitative or semi-quantitative data must be analyzed in some cases.
- An assumption that energy development is performed in substantial compliance with applicable environmental regulations.
- An accounting for unique situational or locational factors.
- The temporal nature of the impacts.

Those factors must be equitably analyzed within and among energy development scenarios to objectively describe and compare the various energy resources. It is obvious that the EF analysis can become complex, due to the myriad of factors, variations and methodology issues. The analysis needs to have clearly defined boundaries and assumptions will need to be made and documented. There is no existing comprehensive EF analysis for energy resources and not all of the data may have been collected to date, but a certain amount of data exists with various sources.

A comprehensive, objective EF analysis will support sound public policy to serve the needs of a prosperous and growing society. Undertaking an effort to determine the appropriate methodology and establish a system to collect the necessary information would provide sound analytic results on environmental impacts for policy decisions. This would involve all interested stakeholders through dialogues in public forums to ensure a variety of viewpoints and issues can be heard and discussed. The following sections suggest an approach for conducting such a process and provide an EF analysis example including the issues and gaps involved.

FOOTPRINT ANALYSIS ILLUSTRATIONS

The following examples, including the comparisons and calculations, are hypothetical and are provided only as illustrations of how an analysis can be conducted. Another source of potential information is the NRC's "Hidden Cost of Energy" report (NRC, 209), which recommends a life-cycle assessment for fuels.

A. Primary Life Cycles

(1) Natural Gas Primary Life Cycle

The life cycle of natural gas (NG) includes the development, transportation, and consumption of the resources. Natural gas can be developed from a conventional well, coalbed formation, shale formation, or as a by-product of oil production. It can be produced on land, offshore, near an urban environment, or on rural farmland, private surface, or federally administered land. Approaches to developing natural gas can affect the magnitude of the impacts and necessary activities. The example presented below is for natural gas as a fuel for electric-power generation and for transportation and illustrates potential magnitudes of the environmental footprint for an LCA. Table 2 identifies the primary life-cycle stages, phases and the activities that lead to various resource impacts.

Table 2. Natural Gas Primary Life Cycle.

Stages	Phases	Activities
Extraction of Raw Energy	Exploration	Surface Examinations & Seismic Evaluations Magnetometer & Gravimeter Surveys Drill Exploratory Wells 2D &3D Simulations and 4D Reservoir Geomechanics
	Planning	Economic Analysis Permitting Field Logistics (equipment type, spacing, pad locations, roads, utilities, gathering lines, delivery routes, compressor stations)
	Development	Infrastructure Construction Activities Well Drilling (vertical or horizontal; single or multi-well pads) Fracturing (high volume, standard, CO_2) Water Transport (trucks, temporary pipelines, source drainage) Well Completion (casing, wellhead, lifting equipment installation) Disposal (cuttings, site wastes, naturally occurring radioactive materials [NORM]) Water Treatment (flowback)
Processing	Production	Well Type Dependent (NG wells, NG condensate wells, NG associated with oil) Well Monitoring Produced Water Removal and Treatment Stimulation (acidizing, re-fracturing, etc.) Field Processing (Scrubbers, heaters, glycol dehydration) Gathering (compression, heating, field transfer)
	Centralized Processing	Oil, Condensate & Water Removal Separation of Natural Gas Liquids Sulfur & Carbon Dioxide Removal (sweetening plants)

Stages	Phases	Activities
Transmission & Distribution	Interstate Pipeline System	Construction of New Pipelines Pipeline Inspection & Safety Emergency Response Compressor Stations Metering Stations, Control Stations & Supervisory Control and Data Acquisition (SCADA) Systems
	Storage	Underground Storage Facilities (depleted reservoirs, salt caverns, aquifers) Natural Gas Injection (unrecoverable gas, base gas, working gas) Gas Extraction
	Distribution System	Local Distribution Companies (citygate transfer) Installation of New Distribution Lines Transportation of NG (interstate pipelines to households and businesses) Local Compressor Stations & Depressurized Stations Scrubbers and Filters Odorant (Mercaptan) Addition SCADA Systems & One-call Systems Individual Use Meters (Meter-reading personnel & electronic meters)
Energy End Use	Electrical Generation	Steam Generation Units (efficiency 33-35%) Centralized Gas Turbines (efficiency 30-35%) Combined Cycle Units (efficiency 50-60%) Distributed Generation (efficiency 21-40%) Combined Heat and Power Systems (efficiency 45-80%) Microturbines (efficiency 60-80%) Gas Fired Reciprocating Engines (efficiency 25-45%)
	Fuel	Commercial Space Heating (Direct & Indirect) Residential Heating Cooling (Chillers, Absorption, Desiccant), Cooking & Drying Waste Treatment and Incineration Infrared Heating Units & Direct Contact Water Heaters Co-firing Technologies
	Transportation Fuel (CNG)	Public Refueling Facilities Depot Based Refueling Vehicle Refueling Appliances LNG Tanker Truck Delivery Fleet Vehicles (airports, public transportation, school buses, delivery trucks, train) Indoor Vehicles (forklifts, lift trucks) Personal Vehicles Gallon of Gasoline Equivalent (GGE) (32 mpg Honda Civic GX)

(2) Onshore Wind Farm Primary Life Cycle

This LCA encompasses the primary life cycle of the wind farm, including the transport, erection and infrastructure associated with constructing and maintaining the wind farm and the ultimate disposal of the turbine. The LCA does not include the raw material extraction, processing of raw materials, manufacturing of the wind turbines, and associated transportation. This example applies to large-scale (1.5-megawatt [MW] turbines) onshore – not offshore – wind farms. Table 3 identifies the primary life-cycle stages, phases and the activities that lead to various resource impacts.

Table 3. Wind Farm Primary Life Cycle.

Stages	Phases	Activities
Extraction of Raw Energy	Exploration	Surface Examinations Wind Flow Analyses
	Planning	Economic Analysis Permitting Field Logistics (equipment type, spacing, pad locations, roads, utilities, power lines, delivery routes, electrical substations, transformers, etc.)
	Erection	Infrastructure Construction Activities Transportation of Turbine Parts to Farm (tower, blades, nacelle) Foundation Construction On-site Assembly (Crane)
Processing	Maintenance	Periodic Maintenance Activities (gear lubrication, part replacement, transmission fluid change, transformer station upgrades, blade replacement, etc.)
Transmission & Distribution	Interstate Powerline System	Construction of New Power Line Rights-of-Way Right-of-Way Inspection and Safety Emergency Response Transformer Stations Metering Stations
	Distribution System	Local Distribution Companies
Energy End Use	Electrical Generation	Yaw System Operations

B. Impact Metrics

(1) Surface Impacts

Natural Gas

The average surface disturbance associated with the extraction of natural gas is dependent on the type of development. The disturbances mentioned in various environmental impact documents, including drilling pad and support infrastructure, are generally as follows:

- Coalbed Methane (Natural Gas) (vertical well) – 2.0 acres/well (BLM, 2006).
- Shale Gas (horizontal well) – 1.23 acres/well based on 7.4 acres of disturbance for an average six-well pad site (GWPC-ALL, 2009).
- Conventional Gas – 1.56 acres/well (Whitsitt, 2004).
- Deep Gas – 6.71 acres/well (BLM, 2008).

To determine the amount of surface disturbance associated with the natural gas production needed to power an electric generating facility the methodology in Table 4 can be used.

Table 4. Methodology for Determining Surface Disturbance Associated with Natural Gas.

Action	Description for Natural Gas
Energy produced	Average production rate of gas per well calculated on the life expectancy of the well considering the decline curve
Acres disturbed	Per well including pipelines and compressor stations; calculate a unit “fuel” per acre disturbed
Conversion factor	Using a standard Btu to MWh conversion factor of 3,412,000 Btu/MWh, determine the number of MWh potentially produced (EIA, 2010c) (The Btu to MWh conversion efficiency will depend on the type of technology used for actual comparisons)
Gas calculation	Calculate the amount of natural gas necessary to generate a given annual MWh of electricity equal to the other sources so a comparative analysis can be conducted
Calculate acres per unit of gas	Determine the total acreage disturbed to produce the natural gas necessary to create the annual MW for the analysis
Include Gas Plant or Processing Facility	
Acres disturbed	Disturbance by the gas plant or processing facilities necessary to prepare gas for use
Scale to a power plant	Calculate the number of processing facilities (acreage) necessary to process the volume of natural gas necessary to generate the given annual MW for the analysis – note: this may be a fraction of a single facility (the incremental surface disturbance from this process necessary to produce that quantity)
Include Power Plant	
Acres disturbed	Disturbance by power plant used to generate the electricity (assume combined cycle)
Apply capacity	Apply the appropriate generating plant capacity factor to account for the fact that many plants do not operate at full capacity

Action	Description for Natural Gas
Scale to MWh	Calculate the number of facilities (acreage) necessary to generate the desired annual MWh of electricity (may be a fraction of a single facility)
Sum total acres	Sum the total acres disturbed by production, fuel processing, and electrical generation for total acreage disturbed for the generation of designated MWh of electricity

The following are examples of unique considerations for natural gas in this EF analysis example:

- Regional pipelines or transmission lines are acknowledged surface disturbances, but it is difficult to provide an average distance from source to user that would have universal applicability so this is not included in this example.

- There are existing wells; however new wells are drilled annually to maintain a continuous supply of natural gas at current levels and to augment the existing portfolio (about 19,000 new wells per year and a total of 493,100 producing wells today) (EIA, 2011).

NATURAL GAS EXAMPLE: SHALE GAS WELLS

Acreage Disturbed. The development of the Barnett Shale in Dallas/Fort Worth, Texas, is a proxy for the parameters typical of shale gas development. The disturbance for each shale-gas well pad is 7.4 acres, accounting for the pad (including production facilities) and the incremental contribution from roads and utilities (GWPC-ALL, 2009). That acreage takes into account interim reclamation of the well and longer-term disturbance present during operating activities. Each well pad can support from four to eight wells; therefore, the per-well surface disturbance is approximately 1.23 acres (ac) for a 6-well pad.

In 2007, there were 7,311 producing Barnett wells (Texas RRC, 2011a) with an annual production of 1,104 billion cubic feet (Bcf) of gas (Texas RRC, 2011b), corresponding to an average rate per well of 151,005 thousand cubic feet (mcf) annually The use of an annualized average production rate per well takes into account the fact that at any given time, different wells are producing from different points on their decline curves; newer wells will produce substantially more, while older wells may produce substantially less.

Calculations for the Generation of 1,000 MWh of Electrical Power. The heat (Btu) content of natural gas is approximately 1,021,000 Btu per mcf although the specific Btu content may vary by the quality of the natural gas. In addition, a thermal-conversion efficiency factor is needed for each technology that uses gas to generate electricity. For this scenario the generation of 1 kilowatt-hour (kWh) of electricity requires 3,412 Btu (EIA, 2010c). Based on these conversion factors, 1 mcf of natural gas will yield 299.2 kWh (0.299 MWh) of electrical power. The generation of 1,000 MWh of electricity will require the delivery of 3,342 mcf of natural gas. Based on the average annual production for a Barnett shale well noted above, the generation of 1,000 MWh annually (8,760 hours) would require 194 wells. Note that the production averages represent the amount of natural gas that is delivered to the pipeline and therefore any upstream losses from venting, flaring, or leaks are realized in the production numbers. Based on an average disturbance of 1.23 ac per well, the generation of 1,000 MWh will disturb 238 ac (annualized).

The surface disturbance for a given production rate of oil or gas over time is dependent on several factors. The production decline rate over the productive life of individual oil or gas wells and the fact that oil or gas wells may produce at lesser rates for several decades means that at any given point in time numerous wells are producing at various stages of maturity. Just as new wells are drilled, old wells are retired from production ("plugged and abandoned" is the industry phrase). When wells are retired the well site equipment is removed and the well pad is reclaimed to pre-existing conditions (this is based on the assumption of a current well operating in compliance with current regulations). The overall surface disturbance is not cumulative or permanent. Reclamation takes place as old wells are retired, and the entire oil or gas field or region is not fully disturbed in its entirety at any one point in time.

Additional Post-Production Facility Surface Disturbance Acreage. The average gas processing plant and typical quantity of gas process was done by using the Elk Basin Gas Plant as a proxy for a typical midsized gas processing terminal. The acreage of this facility is 21.25 acres and it is capable of treating up to 24,000 mcf/day (Anadarko 2008), yielding an average surface disturbance of 0.02125 acre per mcf/hour. At this average a facility capable of processing the 3,342 mcf/hour required to generate 1,000 MW every hour would be approximately 71 acres.

Gas-Fired Power Plant Surface Disturbance. There are 472 combined-cycle power plants listed in the EIA Annual Electric Generator Report for 2008. These plants were divided into 10 groups based on nameplate capacity from smallest to largest, each having approximately 47 plants. Each group was analyzed and the mean nameplate capacity for that group identified. The mean for each group was used to identify a representative plant with the nameplate capacity closest to the mean. Each of these ten representative plants was analyzed using Google Earth online software (http://www.google.com/earth/index.html) to approximate their surface disturbance. The 10 representative gas-fired combined-cycle power plants used in the analysis are identified in (**Table 5**). The average acreage disturbed per MW was found to be 0.165 acre, meaning that a 1,000 MW facility would require approximately 165 acres.

Table 5. Estimated Surface Disturbances of Example Gas-Fired Power Plants.

Electric-Power Generation Facility	Estimated Facility Acres	Location	Generating Units on Location	Nameplate Capacity (MW)	Unit Types
Lederle Laboratories	~1	Rockland, NY	5	23.4	CT/CA
Sterling Power Plant	~1	Oneida, NY	2	64.2	CT/CA
Foster Wheeler Martinez	24	Contra Costa, CA	3	113.5	CT/CA
Grays Ferry Cogeneration	18.8	Philadelphia, PA	2	192.6	CT/CA
Las Vegas Cogeneration LP II	11	Clark, NV	6	297.6	CT/CA
Arvah B. Hopkins	93.3	Leon, FL	2	446.7	CT/CA

Electric-Power Generation Facility	Estimated Facility Acres	Location	Generating Units on Location	Nameplate Capacity (MW)	Unit Types
Putnam	30.2	Putnam, FL	6	580	CT/CA
Dogwood Energy Facility	48.8	Cass, MO	3	677	CT/CA
Barry	217	Mobile, AL	5	900.7	CT/CA
Dynegy-Moss Landing	333	Monterey, CA	6	1398	CT/CA
Average:	**77.81**		**Average:**	**469.37**	

CT/CA – Combined Cycle Combustion Turbine / Combined Cycle Steam
Source: Acreage Google Earth, © 2010., Nameplate Capacity and Generating Units - Form EIA-860, "Annual Electric Generator Report," - Generator (Existing) File, Existing Generating Units in the United States by State, Company and Plant, 2008

The average capacity factor for combined cycle gas-fired power plants from 2003 to 2008 has steadily increased from 33.5 to 42 percent (EIA, 2010b), meaning that the plant produced at its maximum capacity for the equivalent of 42 percent of the time. Multiple power plants of the average nameplate capacity in Table 5 would be needed to generate 1,000 MWh of electrical power. In order to provide fully comparable acreage disturbance numbers for the different energy sources, the acreage from the power plants must also be considered. Gas wells are producing at the annualized rate regardless of whether a given power plant is operational or not. This natural gas is available to be used at another power plant when the initial plant is not operational or is not operating at full capacity. Therefore, it is not necessary to increase the number of gas wells to produce the 1,000 MWh.

The capacity factor percentage was divided into the 165 acres required for a 1,000-MW facility and yielded acreage of 393. Combined additional surface disturbance due to post production processing facilities and power plants is 464 acres. The combined disturbance for production, processing, and electrical generation via natural gas is 702 acres. It is important to understand that just as the gas well disturbance does not recur every year in a cumulative sense, the disturbance from the power plants is also a constant over its useful lifetime and is not a cumulative disturbance.

Based on preliminary analysis the surface disturbance required to add 8,760,000 MWh annually to the grid or a new 1,000MW-capacity power plant at full capacity utilizing natural gas would require the following disturbance depending on the supply source (AESF, 2010):

- Coalbed Methane (Natural Gas) – 2,414 acres
- Conventional Gas – 2,258 acres
- Shale Gas – 702 acres

<u>Calculations for the Generation of Natural Gas to Run a Light Duty Vehicle for One Year</u>

Natural gas as a transportation fuel is becoming more popular as the price of gasoline and diesel increase (U.S. Energy Information Administration, 2010a). To determine the amount of surface disturbance associated with operating a light-duty vehicle (LDV) for one year or approximately 15,000 miles (FuelEconomy.gov, 2011), one can use the calculations conducted for electrical generation and modify them based on the gasoline gallon equivalence (GGE) for natural gas. The GGE for compressed natural gas (CNG) is 126.67 cubic feet (3.587 m^3). This is derived by comparing the base Btu value for a gallon of gasoline at 114,100 Btu to that of compressed natural gas at 900 Btu/cubic ft or about 5.7 lbs. of compressed natural gas (CNG) (Gable and Gable, 2011; Alternative Fuels & Advanced Vehicle Data Center, 2010).

A 2005 Honda Civic CNG car gets 26 city and 31 highway miles per gallon for a 4 cylinder 1.7 L engine (FuelEconomy.gov, 2010a). Using this as a base vehicle one can calculate the needed quantity of natural gas to operate the vehicle for an average year. Assuming that the car is driven 45 percent highway and 55 percent city and a total of 15,000 miles (FuelEconomy.gov, 2010a), the required fuel amount need for one year would be:

[(0.45 x 15000)/31 mpg] x 126.67 cu ft = 27,581 cu ft

[(0.55 x 15000)/26 mpg] x 126.67 cu ft = 40,193 cu ft

Total of 67,774 cu ft (67.774 mcf) or 1,920 cu m

Based on these calculations, the average Barnett Shale natural gas well producing 151,005 mcf annually would provide enough natural gas to operate 2,228 Honda Civics [151,005 mcf/67.77 mcf]. The surface disturbances associated with that level of development would be equal to the 1.23 acres per well divided by 2,228 cars or 0.00055 acres per car. The disturbance for processing would be based on the natural gas processing calculations conducted for surface disturbance associated with a power plant. The Elk basin 21.25 acre facility processes 24,000mcf/day, therefore this facility processes enough gas annually to power 129,260 natural gas vehicles [(24,000mcf x 365)/67.77mcf] or approximately 0.00016 acres per vehicle [21.25 acres/129,260 vehicles]. The total surface disturbance needed to provide enough natural gas to power one vehicle per year would be 0.00071 acres or 31 square feet [0.00055 acres + 0.00016 acres], less space than is required to park the vehicle. It is acknowledged that the amount of natural gas lost from the processing facility to the fueling station, if any, should be added to the amount consumed by the cars. Also, any natural gas leakage from the vehicles should be factored in to the calculation, but for now this data remains elusive.

Wind Power

It is necessary to follow the same basic methodology as described for natural gas to determine the amount of surface disturbance associated with a wind turbines for a specific amount of annualized electric-power generation. The key parameters are nameplate capacity and acreage disturbed.

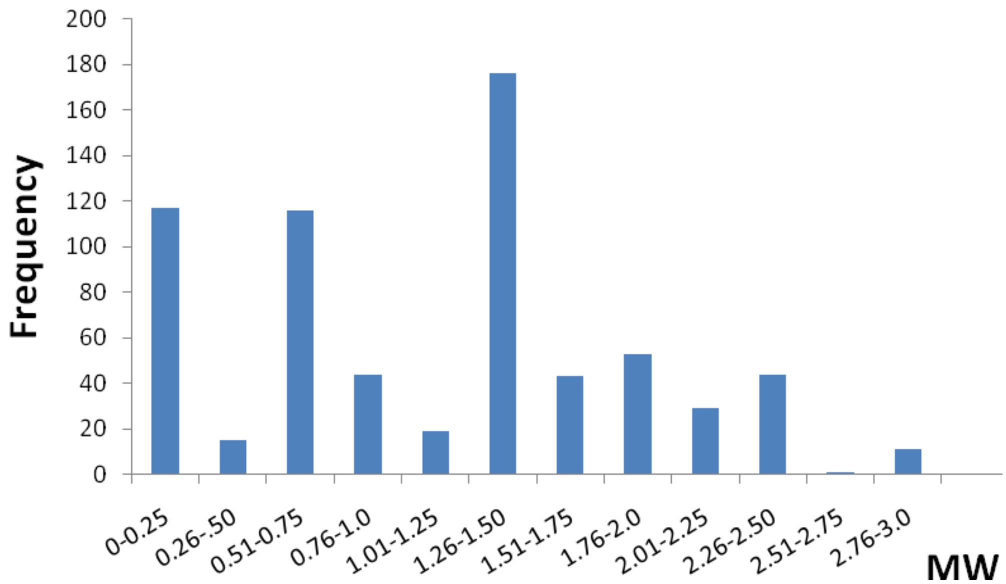


Figure 2. Wind Generator Frequency Plot.
Source: American Wind Energy Association (AWEA), "Resources: U.S. Wind Energy Projects" (2010), http://www.awea.org/projects (accessed January 2010).

Figure 2 presents a frequency distribution plot of wind turbine generator nameplate capacity of all wind power projects (668 wind farms located in 40 states) in active operation between 2001 and 2009 in the U.S., based on data obtained from the American Wind Energy Association (AWEA) (American Wind Energy Association, 2010). The mode or most frequently used turbine size is approximately 1.5 MW. The typical 1.5 MW generator has an approximate 70 meter (m) rotor diameter (Iowa Energy Center, 2007). These basic generator specifications were used in the following calculations.

According to BLM's Programmatic Environmental Impact Statement (PEIS) for wind power (BLM, 2005), the actual land disturbance (tower pad plus associated roads and supporting buildings) is less than 2 percent of the total leased (developed) land and approximately 0.52 to 0.68 acre per MW of disturbed land (Table 6). Note that it is not clear if those numbers includes incremental portions of power collection lines and substation. Denholm et al. (2009) found an average total land use for wind farms of 34 hectares (84 acres) per MW of nameplate capacity which is higher than the value of 36 ac/MW (=66.3 ac/1.84 MW) implied by the data in Table 6.

Table 6. Representative Wind Farms (BLM, 2005).

Project	Total Capacity	# Turbines	Total Leased Acreage	Disturbed Acreage
Nine Canyon Wind Project	*69 MW*	*49*	*5,120 ac*	*47 ac*
Wild Horse Wind Project	*312 MW*	*158*	*8,600 ac*	*165 ac*
Average Capacity per Generator		1.84 MW		
Average Total Leased Acreage per generator			66.3 ac	

Project	Total Capacity	# Turbines	Total Leased Acreage	Disturbed Acreage
Average Disturbed Acreage per generator				1.02 ac
Average Disturbed Acreage per MW Generated				0.55 ac
Average Total Acreage per MW of Nameplate Capacity				36 ac

WIND POWER EXAMPLE: A 1,000 MW WIND FARM

Acreage Disturbed. For a 1,000-MW wind farm developed using 1.5-MW turbines, approximately 667 turbines would be required. Assuming 1.02 acres per turbine represents the actual surface disturbance, the generic wind farm would disturb approximately 680 acres. In other words, approximately 2 percent of the total leased area (31,784 ac) is disturbed; this is consistent with the information provided in the BLM PEIS (BLM, 2005).

Continuity of Power Generation. Power generated by a wind turbine will vary because the wind does not always blow and the velocity of the wind when it blows is not consistent. The relative rate at which wind turbines generate at nameplate capacity is estimated at 35 percent (referred to as nameplate capacity factor). This does not mean that the turbine generates power 35 percent of the time and no power for 65 percent of the time; in fact, a turbine may be generating as much as 50 to 80 percent of the time, but not at full capacity (McDonald et al., 2009; Interwest Energy Alliance, 2011). This does not factor in the efficiency with which the turbine converts the energy from the wind into electricity that can be delivered to the grid. It is simply a reflection of the availability of wind as a resource for electricity generation at the stated nameplate capacity.

Based on a 35 percent nameplate capacity factor, the wind farm required to generate a consistent 1,000 MWh of power would involve a total of 1,905 turbines (=1,000/(1.5*0.35)) with a disturbed area of 1,943 acres (=1,905*1.02), or approximately 3 sq. mi. However, the actual land area leased would be expected to fall within the range of 102,800 acres (=1,000*36/0.35), based on scaling from Table 6, to 240,000 acres (=1,000*84/0.35), based on scaling from Denholm et al. (2009).

Biofuel

Biofuels are included here as a resource comparable to natural gas as a transportation fuel. The most common sources of oil for biodiesel production in the US are soybean oil and yellow grease (primarily, recycled cooking oil from restaurants) (Radich, 2004). Blends of biodiesel and petroleum diesel are designated with the letter "B," followed by the volumetric percentage of biodiesel in the blend: B20, the blend most often evaluated, contains 20 percent biodiesel and 80 percent petroleum diesel; B100 is pure biodiesel. Subsequent analyses presented here are focused on biodiesel fuel derived from soybeans and used as fuel in a LDV.

Data pertaining to the production of soybeans is shown in Table 7 below (U.S. Department of Agriculture).

Table 7. Soybean Production Data, 2004-2009.

Exhibit 9: Soybean Production Data, 2004-2009						
Year	**Planted All Purposes 1**	**Harvested 1**	**Yield 2**	**Production 3**	**Price per Unit 4**	**Value of production 5**
2009	77,451	76,407.00	44.00	3,361,028		
2008	75,718	74,681.00	39.70	2,967,007	9.25	27,398,638
2007	64,741	64,146.00	41.20	2,677,117	10.10	26,974,406
2006	75,522	74,602.00	42.70	3,196,726	6.43	20,468,267
2005	72,032	71,251.00	43.00	3,068,342	5.66	17,297,137
2004	75,208.00	73,958.00	42.20	3,123,790	5.74	17,895,510
	Average: 75,208	Average: 72,508	Average: 42.13	Average: 3,065,668		

The following are the Unit(s) used above.
1 - thousand acres 2 - bushel 3 - thousand bushels 4 - dols / bu 5 - thousand dollars
Sources: USDA, National Agricultural Statistics Service, Crop Production 2010 Annual Summary, January 2011 ISSN: 1057-7823, http://usda.mannlib.cornell.edu/usda/current/CropProdSu/CropProdSu-01-12-2011_new_format.txt ; ibid, 2007 Annual Summary, January 2008 Cr Pr 2-1 (08); ibid, 2006 Annual Summary, January 2007 Cr Pr 2-1 (07); http://usda.mannlib.cornell.edu/MannUsda/viewDocumentInfo.do;jsessionid=E02908A3773043ACE24014BC9D28BF5A?documentID=1047

The average annual production of soybeans in the United States from 2004 to 2009 is 42.13 bushels per acre. One bushel of soybeans can produce 11.28 pounds of soybean oil (FAPRI, 2006). For one gallon of biodiesel, 7.7 lbs. of unrefined soybean oil are required (FAPRI, 2006). The heating value of biodiesel (B100) is 118,296 Btu/gal, or 4,968,432 Btu per barrel (bbl) (National Biodiesel Board, 2005). Therefore, the GGE is 0.96 gallon of biodiesel per gallon of gasoline, whereas regular diesel is 0.88 GGE based on 129,500 Btu/gal.

BIODIESEL EXAMPLE: DIESEL-POWERED LDV

Acreage Disturbed. The LDV selected for the biodiesel footprint calculations is the Volkswagen Golf Turbo Diesel (2002) which is a comparable to the Honda Civic (used as the LDV in the natural gas example) and is listed at 42 mpg city and 49 mpg highway for normal petroleum diesel as fuel (FuelEconomy.gov, 2010b). The energy content per gallon of biodiesel is approximately 11 percent lower than that of petroleum diesel. Vehicles running on B100 are therefore expected to achieve 11 percent fewer miles per gallon of fuel. Therefore, for the following calculations fuel efficiency is reduced to 37 mpg city and 44 mpg highway for the 15,000-mile annual usage (same annual usage as in natural gas example):

((0.45 x 15000)/44 mpg) x 7.7 lbs. = 1,181 lbs. soybeans

((0.55 x 15000)/37 mpg) x 7.7 lbs. = 1,717 lbs. soybeans

(2,898 lbs. /11.28 lbs.) / 40.76 bushels = 6.3 acres/year

Therefore, 6.3 acres of land would be devoted to growing soybeans to provide the annual biodiesel fuel for each diesel-powered LDV.

Additional Post Production Facility Surface Disturbance Acreage. The average gas processing plant and typical quantity of gas process was found by using Google Earth online software to approximate the surface disturbance of six biodiesel refineries located throughout the US (Table 8). The average land area disturbed per barrel per hour of refining capacity was found to be 0.42 acre. For an average fuel efficiency of 40 mpg, and a corresponding volumetric requirement of 375 gal over 15,000 miles driven, the refining footprint would be 0.00043acres/automobile (=39.4/(34,583,332/375)).

Table 8. Biodiesel Refinery Surface Disturbance.

Refinery	Acres	State	Annual Production (gal)	Bbls per hour
Owensboro Grain	19.54	KY	50,000,000	135.90
Cargill	23.62	IA	37,500,000	101.92
Mid America Biofuels	2.93	MO	30,000,000	81.54
Minnesota Soy Bean Processors	90.70	MN	30,000,000	81.54
Peter Cremer NA	18.76	OH	30,000,000	81.54
AGP	80.58	MO	30,000,000	81.54
	Average: 39.4		**34,583,332**	**Average: 94.00**

(2) Air Quality Impacts

Natural Gas

The exhaust emissions from the fuel production and transportation activities necessary to bring the natural gas to the power plant are key to calculating the emissions associated with the development stage in the primary LCA. Emissions include exhaust and fugitive releases associated with all exploration, planning and development activities. Environmental Impact Statements and other existing analyses representing natural gas development are sources of relevant emissions data.

Emissions used here are based on the amounts emitted to produce a given unit of electrical energy (MWh) using natural gas and pulverized coal as the electric-power plant fuels. The analysis was limited by publicly available data which do not include all life-cycle phases or applications. In general, emissions from producing and transporting fuels are small compared to those from burning the fuels to produce electricity. **Table 9** shows the LCA air emissions from raw material extraction, raw material transport, and energy conversion for both natural gas (NGCC plant w/o CCS) and coal (pulverized coal plant w/o CCS) for electric generation in lbs./MWh.(NREL 2010a & 2010b)

Table 9 shows that there are air emissions associated with every stage of the LCA. The largest emissions for natural gas originate from combustion sources in transporting the gas down the pipeline. The largest emissions for coal originate at the plant during combustion of the fuel.

Greenhouse Gases

A change in the methodology employed by the EPA led to a substantial upward revision of estimates of GHG emissions attributable to "Natural Gas Systems" which are defined as the combination of wells, processing facilities, and all transmission and distribution pipelines (EPA, 2010, 2011). Using the year 2008 as an example, EPA (2010) reported 96.4 million metric tons of carbon dioxide equivalent (MMtCO2e) methane emissions from Natural Gas Systems but EPA in 2011 revised the figure to 211.8 MMtCO2e or approximately 3 percent of the total CO_2 equivalent emissions in the United States (EPA 2010). Among the methodology changes adopted during 2010-2011, EPA added emissions estimated for liquid well unloading, completion and workover of unconventional gas wells, and associated hydraulic fracturing work.

For purposes of calculating the air-emissions portion of the EF, one approach to accommodating EPA's revised opinion on natural gas is to update a previous life-cycle analysis of GHG emissions from natural gas and coal use in the power sector (EPA, 2011). Starting with the analysis by Jaramillo et al. (2007), which compared the life-cycle air emissions of coal and different forms of natural gas used for electrical generation, the new EF analysis (NPC Study) presented here adds the impact from EPA's additional methane emissions attributed to natural gas production and transportation. Based upon the boundaries and assumptions of this updated life-cycle analysis, modern natural gas-fired power plants are at least 50 percent lower in GHG emissions than coal-fired plants.

The following boundaries and assumptions are used in the new analysis:

- Direct combustion and fugitive and vented emissions from the production/extraction, processing, transportation, and electrical generation using both coal and gas are included.
- To ensure a fair representation of the current power production sector, promising technologies which are not generally deployed (like carbon capture and sequestration (CCS) or integrated gas combined cycle (IGCC)) are not included.
- Emissions related to construction and decommissioning of the facilities are not included.
- A global warming potential (GWP)[1] of 25 for methane rather than 21 which was used by Jaramillo et al. (2007) and is based on the Intergovernmental Panel on Climate Change (IPCC)'s Second Assessment Report (SAR) is used.

The EF fuel-based analysis for natural gas and coal primarily considers the following emitting components:

- Upstream CO2 from combustion – compressors and process equipment used to produce, process and transport the gas, including indirect emissions from electricity consumption;
- Fugitive and vented methane emissions from the field and power-generation processes.
- Non-combustion CO2 released from the processes – CO2 that is removed from the raw natural gas and vented.
- End-use combustion – the CO2 released from the end-use combustion of the natural gas.

The Jaramillo et al. (2007) estimates of upstream CO2 emissions from fuel and electricity consumed for coal mining were based upon 1997 data, which are updated to 2007 for the new analysis. After applying the above updates and adjustments and normalizing the results to CO2e/MMBtu, Table 10 compares the results from the new analysis for the two fuel types.

[1] A 100-year time horizon GWP value from 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4). For methane, the GWPs range from 72 (for 20 year time horizon) to 7.6 (500 year time horizon). See Table 2.14 (http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter2.pdf). 100 year time horizon is the commonly adopted for various regulations (e.g. AB32, EPA Reporting Rule) and legislative proposals (e.g. 111th Congress). The 100-year time horizon is also the estimate employed by the EPA and EIA in its emissions estimates and projections.

Table 10. : Comparison of Fuel and Upstream Emissions (lb. CO2e/MMBtu).

Emission Source	Natural Gas	Coal
Methane Emissions (Fugitive and Vented)	18	7.9
Upstream Combustion	9.1	5.0
Raw Material Combustion & Venting	2.6	--
Fuel Combustion	117	209
Total	147	222

The GHG emissions of both fuels are dominated by the CO2 produced by fuel combustion (Table 10). Thus, the EPA's increased methane estimates (2011) from fugitive and venting emissions have a relatively small impact on the total GHG emission levels.

The next step in the EF analysis is to consider GHG emissions for each fuel from the generation of electricity which requires an assessment of the efficiency of electric power plants with the comparable results shown in lb. CO2e/MWh. Table 11 depicts the results of this comparison for three different heat rates (thermal conversion efficiencies) for each fuel type.

Table 11. Comparison of LCA Electricity Emission Rates

Natural Gas		Coal	
Heat Rate (Btu/kWh)	NPC Study (lb. CO_2e/MWh)	Heat Rate (Btu/kWh)	NPC Study (lb. CO_2e/MWh)
5,884	866	9,224	2047
12,189	1794	11,377	2524
7000	1030	9,000	1997

The resultant GHG emissions for natural gas are roughly one-half those of coal for each heat rate (Table 10). Figure 4 provides a comparative analysis of the results from the new life-cycle analysis (NPC Study) with results as reported by Jaramillo, et al., the National Energy Technology Laboratory (NETL) and the Pace analysis for the Center for LNG (CLNG) (Pace, 2009). After accounting for higher GWPs for methane and also higher EPA methane emission factors, the new analysis estimates for natural gas combined cycle (NGCC) were comparable to estimates from NETL. The Jaramillo estimates were not adjusted for the new EPA emissions but were adjusted to account for the higher GWPs. The Pace/CLNG had the lowest estimates for NGCC and employed GWPs from the IPCC second assessment report.

For natural gas used as fuel for electric-power generation, the increased EPA methane emission factors applied to the Jaramillo et al. (2007) analysis increases the GHG emissions in the LCA by about 6 percent. For efficiencies typical of new coal and gas-fired plants, the gas-fired plants are about 50 percent lower in GHGs than coal plants on life-cycle basis with an efficient super critical pulverized coal plant and about 60 percent lower relative to an inefficient pulverized coal plant. In regard to the true GHG emissions from Natural Gas Systems, the EPA (2011) estimates should be considered subject to revision once actual measurements become available. Nationwide efforts are ongoing to document process and fugitive emissions of methane as part of preparations in anticipation of future mandatory reporting of GHG emissions by the oil and gas industries to the E PA. Those baseline measurements should become essential in realistic benchmarking of GHG emissions from different fuel sources, including gas and coal.

The generating technology and fuel choice have a large influence on the resulting air emissions for each MWh of electricity produced (Fig. 4). Figure 5 compares the emissions, in pounds, of five major air pollutants – NO_x, PM, SO_2, VOC, and CO – for natural gas, from the generation of one MWh of electricity.

Additional air pollutants can be emitted from various activities associated with bringing natural gas to market. Therefore, to the extent that data and standards exist, those other pollutants should be included in more expansive EF analyses.

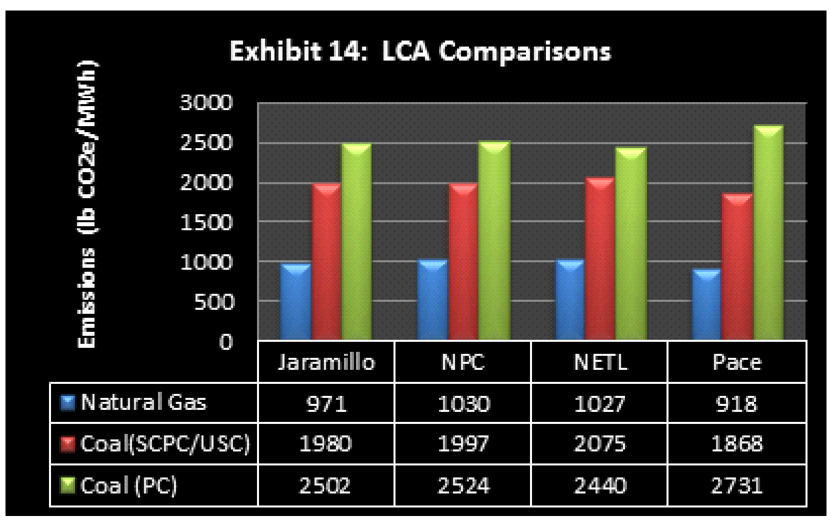


Figure 4. Comparison of emission estimates for natural gas and coal used as fuel for electric-power generation (Pace, 2009).

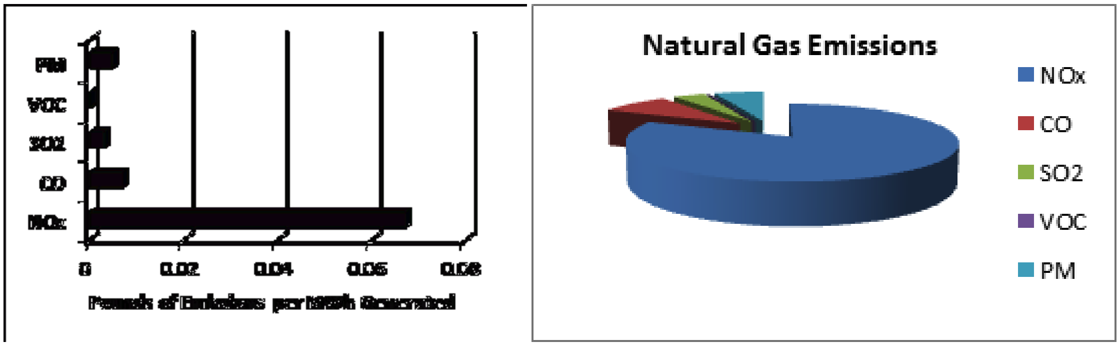
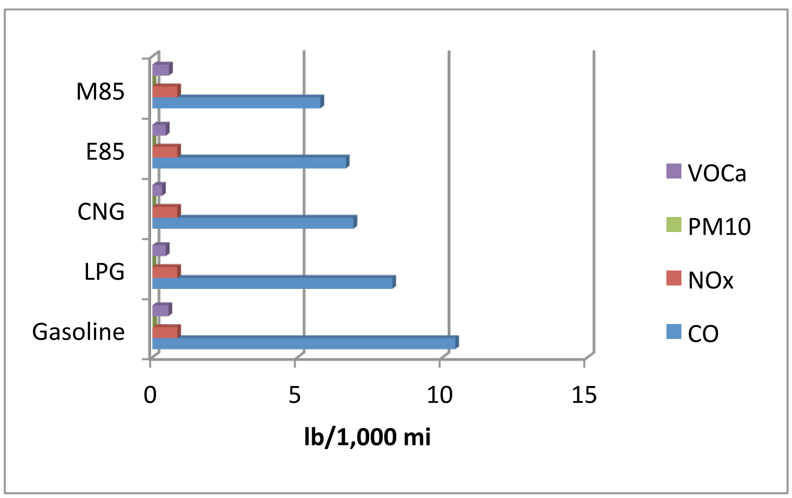


Figure 5. Emissions for Natural Gas for Electric Power (pounds/MWh) (EIA, 2010d).
Source: National Renewable Energy Laboratory (NREL), "Table 3-3 Life Cycle Analyses: Natural Gas Combined Cycle (NGCC) Power Plant," DOE/NETL-403/110509 (September 2010), available at http://www.netl.doe.gov/energy-analyses/pubs/NGCC_LCA_Report_093010.pdf (accessed March 18, 2011).

Transportation Fuel

Transportation accounts for approximately 30 percent of the US consumption of energy (U.S. Energy Information Administration, 2010e). Most of the emissions from transportation are from fuel combustion, including gasoline or diesel fuel, ethanol, methanol, and electricity generation for hybrid or electric cars. The main policy debate regarding fuels and transportation involves the efficiency of LDVs, including cars and light trucks, and the fuels used.



a - May contain ethane.

Figure 6. Example of Energy End Use – Comparison of Light Duty Vehicle (LDV) Emissions Based upon Fuel Type (pounds per 1,000 miles) (Delucchi et al., 2006).
Source: Mark Delucchi (with assistance from Quanlu Wang and Raju Ceerla), *Emissions of Criteria Pollutants, Toxic Air Pollutants, and Greenhouse Gases, from the Use of Alternative Transportation Modes and Fuels*, UCD-ITS-RR-96-12, rev. and reformatted ed. (Davis, CA: Institute of Transportation Studies, University of California, Davis, 2006), Table 14.

Figure 6 compares the emissions of four air pollutants for five fuels. Emissions from gasoline are greater than those from every other fuel type; the others in descending order are liquefied petroleum gas (LPG), CNG, E85 (fuel consisting of 85% ethanol and 15% gasoline), and M85 (fuel consisting of 85% methanol and 15% gasoline) (NRC, 2009; Delucchi et al., 2006;

Guttikunda, 2010; E85, 2011). Carbon monoxide emissions dominate over the other air pollutants for every fuel type, followed by NOx.

Figure 7 shows just the carbon monoxide data and compares emissions for the five fuels. The emissions per vehicle apply to over 250 million gasoline-fueled LDVs that are on the road in the US (BTS, 2010). For example, if each LDV that emits about ten pounds of CO over 1,000 miles, the cumulative emissions comprises over 1.2 million tons of CO. LDVs also emit greenhouse gases, primarily CO_2, methane, and nitrous oxide (NRC, 2009). Figure 8 compares GHG emissions from four major transportation fuels in CO_2 equivalents. These GHG emissions are based upon the GREET model Emission Factors for LDA in 2005[2] Gasoline emits the most GHGs (in CO_2 equivalents) and CNG the least.

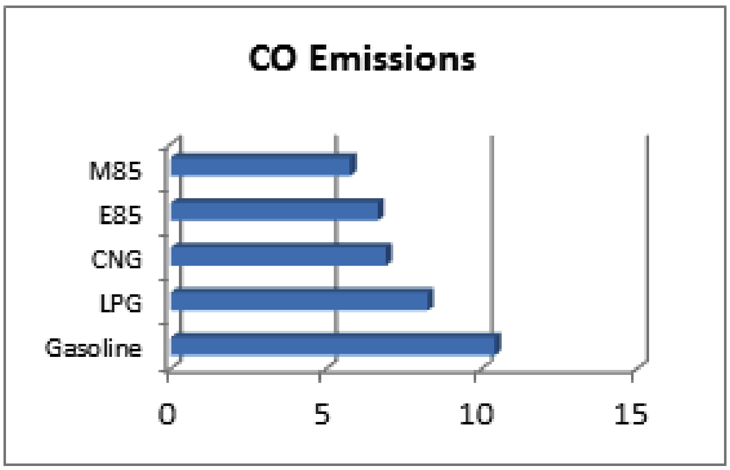


Figure 7. Comparison of Light Duty Vehicles CO Emissions (lb./1000mi).
Source: Same as Figure 6

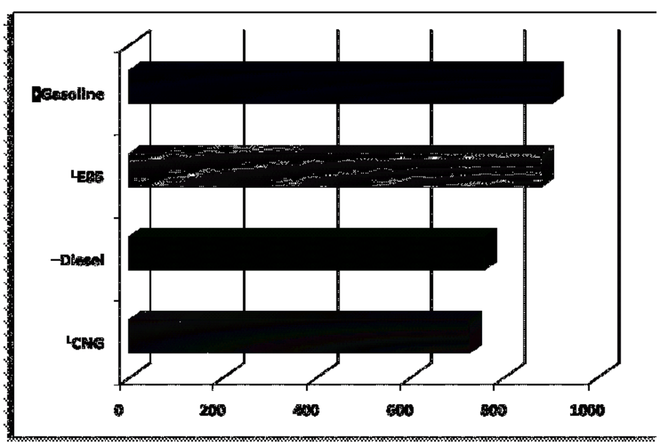


Figure 8. GHG Emissions from Transportation Fuels (pounds of CO_2e per 1,000 miles traveled) (NRC, 2009). Source: Board on Environmental Studies and Toxicology, et al., Hidden Costs of Energy, Table D-3.

[2] Argonne National Laboratory, The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
(GREET) Model, http://www.transportation.anl.gov/modeling_simulation/GREET/.

Natural Gas. Emissions from natural gas-powered vehicles are usually lower than those from gasoline-powered vehicles (TIAX, 2007). For example, the Honda Civic GX fueled on compressed natural gas (CNG) creates 95 percent less emissions of non-methane hydrocarbons, and 75 percent less emissions of NOx than its gasoline twin. Dedicated NG vehicles generate very little evaporative emissions during fueling and use whereas with gasoline vehicles, evaporative and fueling emissions account for a measureable portion of the emissions associated with operating a vehicle (SAIC, 2006). NG vehicles generally provide the following reductions as compared with of gasoline vehicles:

- Carbon monoxide (CO) by 70%-90%
- Non-methane organic gas (NMOG) by 50%-75%
- Nitrogen oxides (NOx) by 75%-95%
- Carbon dioxide (CO2) by 20%-30% (NRC, 2009).

Per unit of energy, natural gas contains less carbon than any other fossil fuel, and thus produces lower CO2 emissions per vehicle-mile traveled. While NG vehicles emit methane, any increase in methane emissions is more than offset by a substantial reduction in CO2 emissions compared to other fuels. Recent analyses estimate that NG vehicles produce up to 20-30 percent less GHG emissions than comparable diesel and gasoline fueled vehicles (TIAX, 2007). In the full life-cycle analysis prepared for the EF analysis, additional EF elements will include emissions for upstream contributions from natural gas delivery and production systems.

Biofuels. About 11 percent of the weight of B100 is oxygen. The presence of oxygen in biodiesel improves combustion and reduces hydrocarbon, CO, and particulate emissions. Oxygenated fuels also tend to increase NOx emissions. Engine tests have confirmed the expected increases and decreases of each exhaust component from engines without emissions controls (NREL, 2001). Adding cetane enhancers – di-tert-butyl peroxide at 1 percent or 2-ethylhexyl nitrate at 0.5 percent – can reduce NOx emissions from biodiesel (NREL, 2001).

Nitrogen oxide emissions from biodiesel blends could possibly be reduced by blending with kerosene or Fischer-Tropsch (synthetic) diesel. Kerosene blended with 40 percent biodiesel has estimated emissions of NOx no higher than those of petroleum diesel, as does Fischer-Tropsch diesel blended with as much as 54 percent biodiesel (McCormick et al., 2003). Those results imply that Fischer-Tropsch diesel or kerosene could be used to reduce NOx emissions from blends containing 20 percent biodiesel, although the researchers did not investigate those possibilities.

Wind Power

The air emissions released during the primary life cycle of electricity generated from wind are limited to the surface examination, transportation, erection, infrastructure construction, maintenance, and replacement or decommissioning of the individual turbines. The construction of a wind turbine pad includes the building of a foundation and the erection of the turbine. The foundation is made on site and in general is based on the weight and configuration of the proposed turbine, the expected maximum wind speed, and the soil characteristics at the site. A typical foundation for a 1.5 MW turbine consists of a hole filled with concrete in a inverted "T" configuration approximately 15 m diameter and 2 to 3.5 m deep. This requires from 130 to 240 cu m of concrete for the foundation (Berndt, 2004).

The erection phase includes the transportation of the different parts of the turbine to the site and the erection of these parts by crane in order to assemble the turbine. Therefore, the resource used is mainly fuel and the amount of diesel has been calculated at 1,673 gallons (Nalukowe et al., 2006). The CO2 emissions from a gallon of diesel as calculated on the EPA Emission Fact website is as follows:

> CO2 emissions from a gallon of diesel = 2,778 grams x 0.99 (oxidation factor) x (44/12) (ratio of molecular weight CO2/C) = 10,084 grams = 10.1 kg/gallon = 22.2 pounds/gallon (EPA, 2005).

The estimated total CO2 emitted from the erection activities is 37,140 pounds (=1,673*22.2) or18.6 tons.

The operation of the wind farm requires almost no resources since the turbine uses the energy contained in the wind to produce electricity without emitting any kind of pollutant. Nevertheless, some energy is needed for a yaw system operation, which is used for turning the wind turbine rotor against the wind. For lack of specific data, yaw-system energy use is not included in the total energy consumption calculation. The emissions from the maintenance are mainly fuel consumption from transporting the technicians, spare parts and lubricants from turbine to maintenance shop for regular checkups. The amount of diesel used for maintenance over the 20-year life of a single turbine has been calculated to be 317.01 gallons (Nalukowe et al., 2006).

To calculate the pounds of CO2 emitted by a 1000 MW wind farm annually, the turbine numbers from the surface disturbance and divide by the annual production can be used:

> 1,905 turbines x (317.01/20) = 30,195 gallons x (22.2 pounds) = 670,300 pounds (335 tons) of CO2 annually.

Note that the extremely detailed accounting of emissions during the erection phase of a wind turbine is a prime example of the level of detail required to conduct a full EF analysis. Similar activity would occur with the development of other energy resources, i.e., natural gas well maintenance, nuclear power plant construction, etc., and should quantified in the full analysis.

(3) Water Impacts

The following sections analyze the relative water intensity (amount of water needed) per unit of energy produced and various fuels and electric generation options for raw fuels, electric power, and transportation fuels. The analyses consider the gallons of water needed per unit of energy in order to facilitate a comparison of like fuels or electric generation options.

Natural Gas

Intensity of water use (amount of water needed to accomplish energy delivery) is measured as the gallons of water needed per unit of energy. The analysis utilized the same primary-level LCA as was used to develop impacts for air emissions and surface disturbances. As such, the approach includes water used for extraction and processing of natural gas which includes drilling and completion activities (hydraulic fracturing) in shale gas and in conventional production for purposes other than in the fracturing processes.

An analysis of the raw fuel impact includes the extracted natural gas that is processed and used to generate electricity. The production or extraction of natural gas is typically is measured by volume (mcf) or energy content (Btu). All comparisons made were an evaluation of the gallons of water used to generate a volume of natural gas, so the data are presented below as gallons of water used per MMBtu. All calculations were performed using US Department of Energy (DOE) conversion factors. The values calculated and presented in Table 11 are independent of location because water demands related to transportation were not included in the considerations; in practice, distribution of fuel from source to end user would vary with distance between source and end-user.

As derived for the analysis of surface impacts, generation of 1,000 MWh of electricity requires 3,342 mcf of natural gas. Using as a model water sink, a shale-gas well that uses 3.8 gallons/mcf (Table 12), the 1,000-MWh would require 12,700 gallons of water (=[(3,342*3.8 gallons).

The conversion of the raw fuels to electricity in the United States is primarily performed in thermoelectric power plants (hydrocarbon fuels) and hydroelectric power plants (water as "fuel") (EIA, 2010b). While hydroelectric power plants use direct energy from water to generate electricity, thermoelectric power plants use a transfer of energy from the burning of raw fuel sources to heat water to generate steam. Steam is then used to turn a turbine on a generator, which produces the electricity. The process of generating electricity in a thermoelectric power plant varies in efficiency because of the different technologies that may be used to go from the raw fuel to the turning of the generator's turbine. Combined research by the University of Texas and Environmental Defense Fund reported efficiencies of 33 percent for nuclear turbines, and between 26 percent and 50 percent for raw fuel-fired power plants (Stillwell et al., 2009). Remaining energy generated is lost as waste-heat to cooling water or flue gases for the fossil fuel power plants and nuclear turbines.

Table 12. Water Intensity of Raw Fuels (Natural Gas) (Mantell, 2009).

Energy Resource	Gallons of Water Used per MMBTU Produced	Processes Included
Deep Shale Gas	0.6 – 3.8	Drilling, hydraulic fracturing, processing, and transportation
Other Natural Gas	1 – 3	Drilling, processing, and pipeline transportation
Coal • no slurry transport • with slurry transport	 2 – 8 13 - 32	Mining, washing, and slurry transport as indicated
Nuclear (processed uranium ready to use in power plant)	8 – 14	Mining, milling, enrichment, and fuel fabrication
Conventional Oil	8 – 20	Drilling/completion, production, and refining
Synfuel – Coal Gasification	11 – 26	Mining, washing, and processing into synthetic gas
Petroleum from Oil Shale • Surface retorting • In situ retorting	 22 – 56 15 – 27	Extraction and refining
Petroleum from Tar Sands (Oil Sands)	27 – 68	Extraction and refining
Synfuel – Coal Liquid (Fischer – Tropsch)	49 – 78	Mining, washing, processing from coal to gas liquid and refining
Enhanced Oil Recovery	21 – 2,500	Oil recovery and refining
Fuel Ethanol (irrigated corn)	2,500 – 29,100 (avg. 11,100)	Growth of feedstock, irrigation and processing
Biodiesel (irrigated soy)	14,000 – 75,000 (avg. 45,000)	Growth of feedstock, irrigation and processing
Hydrogen • Steam reforming • Electrolysis	 43 100 – 200	Production and cooling water

In addition to being used in thermoelectric power plants to generate steam, water is also used in cooling systems. There are two types of cooling systems primarily used in the thermoelectric power plants in the United States: open-loop cooling systems in which water that has been used in the cooling process in the power generation process is returned to a water body outside of the plant; and closed-loop cooling systems in which the water in the plant's cooling system is cooled and re-used. Water used in a power plant's cooling system falls into two categories:

- Water withdrawn: Water that has been removed from its source (surface water, groundwater or other) for use.
- Water consumed: Withdrawn water that is lost in the process of creating electricity due to evaporation (discharged water is not considered consumed water because it is returned) (Mantell, 2009).

The use of open- versus closed-loop cooling systems will affect the water intensity of different power plants. An open-loop system will have a larger water withdrawal but, because this water is returned, the water consumption is lower. In contrast, a closed-loop cooling system will have lower water withdrawals but, because the water remains in the system, the water consumption is higher than an open-loop system (DOE, 2006). In assessing the water intensity of the different power plants and cooling systems, water use was standardized to gallons of water used per MWh generated (gal/MWh). This standardization allows for the comparison and assessment of the water intensities of the different facility types to a common basis.

Figures 10-11 compare different power plants by fuel type as well as by cooling system type. The table presents water withdrawals and water consumption rates for the cooling systems as well as water consumption rates for other uses. Other uses of water include other cooling loads, emissions control, equipment washing and sanitation (DOE, 2006).

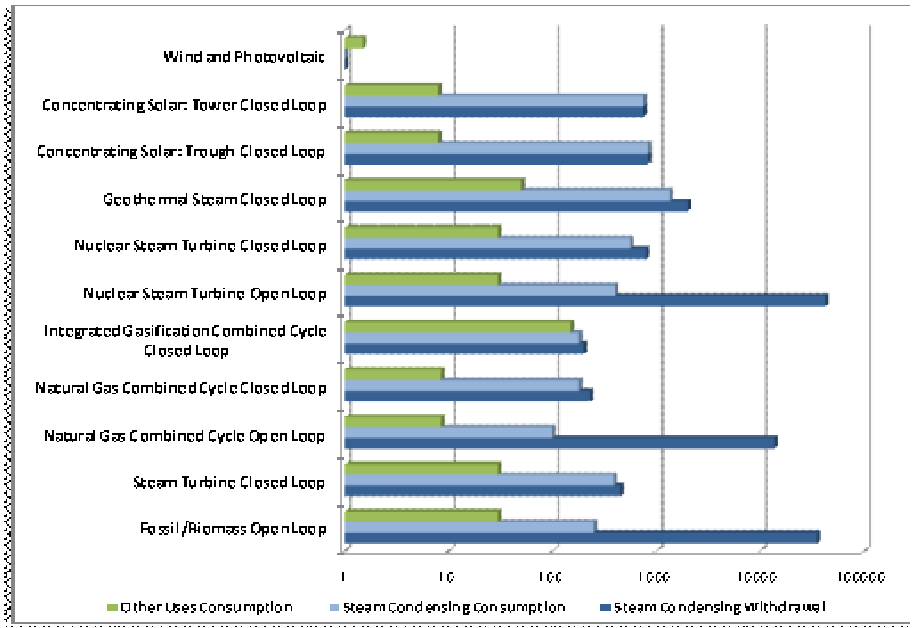
Figure 10. Water Intensity for Electric Power Generation (DOE, 2006).

Plant Type	Cooling Process	Water Use Intensity (gal/MWh)		
		Steam Condensing		Other Uses*
		Withdrawal	Consumption	Consumption
Fossil/Biomass Steam Turbine	Open Loop	20,000-50,000	200-300	~30
	Closed Loop	300-600	300-480	
Natural Gas Combined Cycle	Open Loop	7,500-20,000	100	7-10
	Closed Loop	230	180	
Integrated Gasification Combined Cycle	Closed Loop	200	180	150**
Carbon Sequestration	~25 percent increase in water withdrawal and consumption			
Nuclear Steam Turbine	Open Loop	25,000-60,000	~400	~30
	Closed Loop	500-1,100	400-720	
Geothermal Steam	Closed Loop	2,000	1,350	50
Concentrating Solar: Trough	Closed Loop	760-920	760-920	8
Concentrating Solar: Tower	Closed Loop	~750	~750	8
Wind and Photovoltaic	N/A	0	0	1-2

*Includes water for other cooling loads, emissions control, equipment washing, and sanitation.

** Including process water

Figure 11. Water Use Intensity for Electric Power Generation (gal/MWh) (DOE, 2006).



Power plants with closed-loop cooling systems have water withdrawals that average about 10 percent that of the open-loop cooling systems regardless of the raw fuel source (Fig. 10). Of the closed-looped plants, those which use a gas fuel source, either the natural gas combined or coal synfuel-integrated gasification cycle plants, have the lowest average combined water intensity at 420 gal/MWh and 530 gal/MWh (Fig. 11). While those plants on average consume between 70 percent and 90 percent of the water withdrawn, the overall water withdrawal rates average 50 percent or less of the water withdrawal rates of the other closed-loop plants and 10 percent or less of the withdrawal rates of the open-loop power plants.

The ratio of water consumed from the water withdrawn is a reflection of the efficiency of the plant in generating steam that can be directly applied to the turbine and can be used as measure to assess plant efficiency as it relates to the fuel combustion temperature (Torcellini et al., 2003). Fuel type affects the water consumption as well for many of those plants because fuels combust at different temperatures and generate different waste products (off-gases versus pure steam).

The water withdrawals for the open-loop cooling system power plants are on average one to two orders of magnitude greater than the closed-loop plants (Fig. 10). Natural gas open-loop power plants have the lowest water withdrawal range (maximum water withdrawal rate 20,000 gal/MWh) and on average natural gas open-loop power plants are lower than the minimum average water withdrawal rate for an open-loop power plant that uses fossil/biomass fuel (20,000 gal/MWh) or nuclear fuel (25,000 gal/MWh) (DOE, 2006). The water consumption rates for those open-loop power plants average less than 1 percent of the water withdrawals, so while those systems divert a much larger volume of water for temporary use, more than 99 percent of that water is returned and can be used downstream.

Water Intensity of Transportation Fuels

While the primary transportation fuels of the United States have long been the petroleum-based fossil fuels, gasoline and diesel, there has been a movement to develop non-conventional fuels for the future. The non-conventional transportation fuels include biofuels, hydrogen and electric powering for vehicles, CNG, and synthetic fuels derived from coal and non-conventional petroleum fuels from oil shales and tar sands (Mantell, 2009). In order to facilitate an equitable comparison of the water intensities of the different transportation fuels, the water intensity of a fuel was treated as the number of gallons of water used per 100 miles driven (gal/100 miles driven) which was adopted from previous work performed by King and Webber (2008). Similar to the water intensity of the fuels used to generate electricity, the transportation fuels have both water withdrawn and water consumed data, which have previously been defined.

For the water-related EF analysis there were a number of assumptions made using water-intensity parameters developed by King and Webber (2008):

- Water consumption for refining was calculated at 1-2.5 gallons of water per gallon of product.
- Water withdrawal for refining was calculated at 12.5 gallons of water per gallon of product.
- Future oil shale technologies could cut water consumption in half. (1-3 gal/gal) (OPR, 2007).
- Electric vehicle energy usage = 37 kWh/100 miles. Overall water intensity of electricity used = 0.465 gal/kilowatt-hour (kWh) consumption and 21.4 gal/kWh withdrawal.
- Water used for corn irrigation varies widely, ranging from 80 gal/gal ethanol (in New Jersey) to 1,600 gal/gal ethanol (in Arizona).
- For corn, input energy in farming is allocated separately to grain, stover, and co-products, with an average of 80 percent allocated for corn grain for ethanol, and 54 percent allocated to stover for ethanol when the grain is used for food.
- Water for ethanol processing is 3.5-6.0 gal. water per gal ethanol from grain and 7.3 gal/gal from stover.
- E85 fuel efficiency = 15.1 miles per gallon (mpg), 26 percent less than gasoline.

Figure 12 depicts calculated ranges for water consumed and water withdrawn for various transportation fuels (King and Webber, 2008) except for the biofuels, which are presented separately in the Figure 13. In general, traditional fossil transportation fuels (gasoline and diesel) have a relatively low average water consumption rate of 5-11 gals/100 miles driven and 7-14 gals/100 miles driven. Since gasoline and diesel are the most widely used transportation fuels, those two fuels represent an excellent starting point for the comparison of other fuels.

Fuel	Consumption	Withdrawal	Comments
Gasoline	7-14	63	
Diesel	5-11	46	
Oil Shale	15-37	71-86	Mining and retorting: 2-5 gal/gal of product. Future technologies could halve the water consumption.
Oil Sands	20-46	76-95	Mining and retorting: 3-7 gal/gal of product. Based on Canadian Oil Sands.
Fischer-Tropsch Diesel from Coal	19-58	19-58	
Fischer-Tropsch Diesel from Gas	12-43	12-43	Includes 1 gal/100 miles for hydraulic fracturing.
Plug-in Electric Vehicles – Electricity from Fossil Fuels	24	780	
Plug-in Electric Vehicles – Electricity from Renewables	0	0	
Hydrogen Fuel Cell – H2 from Natural Gas	6	7	Using methane steam reforming.
Hydrogen Fuel Cell – H2 from Water	42	1300	Using electrolysis and electricity from fossil fuels.
Hydrogen Fuel Cell – H2 from Water	3	3	Using electrolysis and electricity from renewable resources.
CNG – Electric Compression	6-7	13-21	5.9 scf/mile
CNG – Gas Compression	3	3	

Figure 12. Transportation Fuels (gallons of water per 100 miles traveled) (King and Webber, 2008).

Fuel		Consumption	Withdrawal
Biofuels: Ethanol (E85) from corn	Corn Grain: Irrigated	130-6,200 (avg.=2,800)	690-11,000 (avg.=3,600)
	Corn Grain: Non-Irrigated	15-35 (avg.=25)	33-56 (avg.=41)
	Corn Stover: Irrigated	260-4600 (avg.=1,900)	560-6300 (avg.=2,300)
	Corn Stover: Non-Irrigated	25	41
	Grain and Stover from the Same Plant, Irrigated	160-3800 (avg.=1,100	340-5,100 (avg.=1,600)
	Grain and Stover from the Same Plant: Non-Irrigated	22-38	41-56
Biofuels: Soy Biodiesel	Irrigated	60-2,400 (avg.=800)	110-2,600 (avg.=1,000)
	Non-Irrigated	1-2	3-12

Figure 13. Transportation Bio-Fuels (gallons of water per 100 miles traveled) (King and Webber, 2008).

There are three fuel types which have average water consumption intensities lower than gasoline or diesel: hydrogen fuel cells, plug-in electric from renewables, and compressed natural gas. For those fuels the water intensity can vary based on the processing fuel. For CNG, which uses gas compression, the water consumed is 3 gal/100 miles driven, while the water consumed for electric compression is around 6-7 gal/100 miles driven.

For hydrogen fuel cells, the method of hydrogen acquisition can affect the consumed water intensity with values ranging from 3 gal/100 miles driven if renewable energy sources are used to 6 gal/100 miles driven when methane steam reforming is used. When conventional fossil fuels are used for hydrogen electrolysis the water consumption intensity increases by 7 to 14 times up to 42 gal/100 miles driven. There is also one biofuel, biodiesel from non-irrigated soybeans, which has average water consumption intensity below gasoline or diesel. Biodiesel from non-irrigated soybeans has a water consumption value between 1 and 2 gal/ 100 miles driven.

Using the shale-play source of natural gas employed in the surface-impact analysis, an average per-well production of 151,005 mcf was found to support 2,228 LDVs that each drive 15,000 miles annually. The corresponding EF for water, for each 15,000 miles driven, then would be 258 gallons of water (=[(151,005*3.8)/2,228]

Wind

Water is not generally consumed in large quantities for the construction, erection or maintenance of wind farms. It is possible to calculate the water used to mix the concrete and for other relatively small uses but the majority of these activities would be considered secondary life-cycle operations and cumulatively would not amount to a substantial contribution over the anticipated 20-year life of a typical wind turbine.

(4) Community Impacts

Potential impacts to communities associated with the development phase of natural gas include:

- Increased truck traffic to support the drilling and fracturing operations.
- Short-term noise and visual changes.
- Altering rural landscape.
- Creation of permanent and temporary jobs.
- Influx of workers and possible increase in crime.
- Increased housing demand and prices.
- Stress on county services (road repair, water treatment) and local school systems.

- Loss of recreation access to certain areas.
- Potential effect on the health of the local population (Witter et al., 2010).
- Disturbance of cultural or historical resources.
- Encroachment of industry on existing water rights.

These community impacts are difficult to quantify. For example, it is difficult to quantify the impact felt by community members even if truck traffic can be assessed. A method to evaluate the magnitude of those impacts to the community is needed to ensure those impacts are included in the EF analysis. To clearly understand the footprint of each energy source the impacts should be expressed in both scientific terms and in terms of and societal relevance. The latter can be used with the environmental categories to account for the community's opinion on the importance of each environmental impact. The societal factors could be derived from third-party research or national polling data to reflect a weight for calculating final environmental footprint impact numbers. Certain societal factors envisioned are risk, wastes, quality of life, and perhaps resource consumption.

CONCLUSIONS AND RECOMMENDATIONS

An LCA environmental footprint analysis is key to making sound decisions about the future of the North American energy economy. The discussion and examples presented in the current report demonstrate the importance of having science-based, consistent, comparative information and data as the foundations for decisions that affect future investments in energy development and use. It also demonstrates the complexity and uncertainty involved in conducting such analyses. Furthermore, the information and data that are needed for complete LCA are often not available, at least in a form that is suitable for comparative analysis.

An accepted methodology to provide the necessary EF and LCA results does not currently exist. In order to have a widely accepted approach to developing of the required information, there is a need for a transparent and inclusive process for developing a standard methodology. An acceptable and meaningful methodology should:

- Include all aspects of the energy life cycle.
- Define the boundaries of the analysis.
- Recognize the different end uses of energy forms.
- Calculate impacts on a common basis for each end use.
- Account for variations in the energy resources.
- Recognize and incorporate uncertainties.
- Incorporate federal and state regulatory requirements.
- Incorporate impacts that cannot be quantified but are important to include in making energy choices.

Stakeholders can be involved in developing the methodology, assessing the availability of and developing a program to gather the needed data and information.

The need for a transparent, accessible, inclusive, widely accepted process suggests that the EF and LCA methodology development should be managed by a Federal agency. The DOE is likely the most logical agency to fund and oversee this important work. The following findings and recommendations result from the consideration of those method-development needs.

A. Findings

- The environmental footprint (EF), on a life-cycle basis, of the available energy sources should be taken into account when making decisions that affect the future energy mix of North America.

- The EF should be measured on a comparable basis so that decision-makers have scientifically sound, comparable, and consistent information to factor into their decisions.

- The development of a defensible, peer-reviewed methodology is needed to develop the required EF information.

- Much of the information and data needed for an EF analysis may exist, but not in the form required or in one that is easily accessible.

- A possible enhancement to the EF analysis would be a risk assessment score for each energy source as an indicator of the likelihood of future environmental catastrophes.

B. Recommendations

- The US Department of Energy (DOE), in consultation with other agencies, should develop a methodology for comparing the life-cycle environmental footprint (EF) of various energy sources, using a public process with input from all interested stakeholder groups.

- DOE should assess the availability of the information and data needed to implement the EF methodology and fund and manage a program to collect and analyze the necessary data.

- DOE should publish and regularly update a life-cycle assessment (LCA) of the environmental footprint of the energy sources expected to make a weighty contribution to the future North American energy economy, including the types of impacts listed above, taking into account variations by resource type and location, and discussing the uncertainties in the analysis.

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