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Direct Carbon Fuel Cells: Assessment of their Potential as Solid Carbon Fuel Based Power Generation Systems

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Disclaimer

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Direct Carbon Fuel Cells: Assessment of their Potential as Solid Carbon Fuel Based Power Generation Systems

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Introduction

Small-scale experimental work at Lawrence Livermore National Laboratory (LLNL) has confirmed that a direct carbon fuel cell (DCFC) containing a molten carbonate electrolyte completely reacts solid elemental carbon with atmospheric oxygen contained in ambient air at a temperature of 650-800 °C. The efficiency of conversion of the chemical energy in the fuel to DC electricity is 75-80% and is a result of zero entropy change for this reaction and the fixed chemical potentials of C and CO2. This is about twice as efficient as other forms power production processes that utilize solid fuels such as petroleum coke or coal. These range from 30-40% for coal fired conventional subcritical or supercritical boilers to 38-42% for IGCC plants.

A wide range of carbon-rich solids including activated carbons derived from natural gas, petroleum coke, raw coal, and deeply de-ashed coal have been evaluated with similar conversion results. The rate of electricity production has been shown to correlate with disorder in the carbon structure.

This report provides a preliminary independent assessment of the economic potential of DCFC for competitive power generation. This assessment was conducted as part of a Director's Research Committee Review of DCFC held at Lawrence Livermore National Laboratory (LLNL) on April 9, 2004.

The key question that this assessment addresses is whether this technology, which appears to be very promising from a scientific standpoint, has the potential to be successfully scaled up to a system that can compete with currently available power generation systems that serve existing electricity markets. These markets span a wide spectrum in terms of the amount of power to be delivered and the competitive cost in that market. For example, DCFC technology can be used for the personal power market where the current competition for delivery of kilowatts of electricity is storage batteries, for the distributed generation market where the competition for on-site power generation in the range of 0.5 to 50 MW is small engines fueled with natural gas or liquid fuels or in the bulk power markets supplied usually by remote central station power plants with capacities of 250-1250 MW that deliver electricity to customers via the transmission and distribution grid.

New power generation technology must be able to offer a significant cost advantage over existing technologies serving the same market to attract the interest of investors that are needed to provide funding for the development, demonstration, and commercialization of the technology. That path is both lengthy and expensive. One of the key drivers for any new power generation technology is the relative amount of pollutant emissions of all types, particularly those that are currently regulated or may soon be regulated. The new focus on greenhouse gas emissions offers a window of opportunity to DCFC technology because of its much higher conversion efficiency and the production of a very concentrated stream of CO2 in the product gas. This should offer a major competitive advantage if CO2 emissions are constrained by regulation in the future. The cost of CO2 capture, liquefaction, and pressurization has the potential to be much less costly with DCFC technology compared to other currently available forms of fossil fuel power generation.

Potential DCFC Markets

Personal Power Market

LLNL is pursing applications of DCFC technology in the military market where the value of the power is mission dependent and much higher that in distributed generation and bulk power applications. The competitive sources of power to meet the demands of this market are batteries, direct methanol fuel cells, and high and low temperature hydrogen fuel cells. The competitive position of DCFC in this market will not be discussed in this review.

Distributed Generation Market

The distributed generation market has a broad span of power capacities. The most likely potential applications of DCFC in this market are at small and medium size industrial sites where 5-50 MW systems could be utilized. The major driver for the installation of on-site power generating equipment is the avoidance of the Transmission and Delivery (T&D) costs that typically are in the range of 1.5 to 3 ¢/kWh. In California, where electricity costs are relatively high, the T&D total is 3.5 ¢/kWh. The assumption has been made that the personnel at this type of site have the capability for handling a solid fuel and operating the anode gas treating equipment that would be necessary for petroleum coke and coal derived fuels.

Bulk Power Market

In this market, power is produced at large-scale plants of 250-1250 MW that deliver power to their customers via the T&D grid. The large scale of operation provides significant economies of production. Usually, there are multiple power generating units at a single site that can share pollution control equipment. In the event that CO2 emission controls are implemented in the future, the large amount of CO2 produced at a single site would be more economically pipelined to a permanent storage site than would be possible at a distributed generation site.

An Idealized DCFC

Figure 1 shows an idealized DCFC. Solid fuel is fed to an anode. The chemical energy in the feed is totally converted either to electricity (75-80%), heat, or small gas molecules (CO_2, COS, H_2, nitrogen compounds). Only preheated ambient air is fed to the cathode. In conventional molten carbonate fuel cells that consume hydrogen at the anode, carbon dioxide must be recycled to the cathode. Residual ash remains in the electrolyte to be removed by subsequent batch processing.

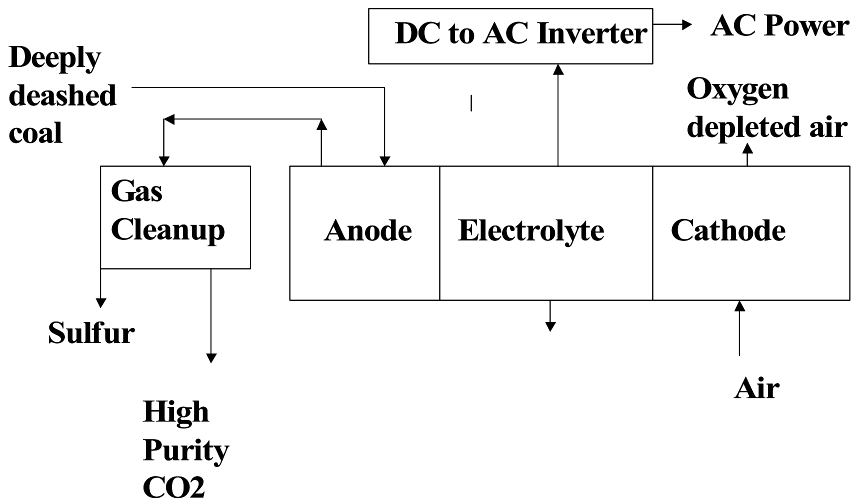

Figure 1. The DCFC converts idealized deeply de-ashed coal to electricity, using an air feed to the cathode.

Review of Current Power Production Technology

Natural Gas Fired Combined Cycle Power Plants (NGCC)

Most of the power generation equipment installed recently in the US has been natural gas fueled simple cycle gas turbines to provide peak load power and combined cycles to produce base load power. The majority of these units were installed to serve the peak load market where high power prices compensate for the cost of natural gas, which is significantly higher than coal. A smaller number of combined cycle units were installed, often in conjunction with an industrial customer for waste steam energy. Most of these plants were installed when natural gas prices were $2.50/MMBtu and were expected to remain at the level for the next two decades. However recent increases of natural gas prices to levels of about $5/MMbtu has idled much of this capacity since it cannot be dispatched in competition with old coal fired plants that have been amortized and have a fuel cost of about $1/MMBtu. Although these new plants are very clean in comparison to coal-fired plants, retrofitting them for CO2 control will be expensive because the concentration of CO2 in the effluent gas is less than 5%.

Supercritical Pulverized Coal Power Plants (SCPC)

Almost all of the power produced from coal in the United States, amounting to about 56% of the total, is produced in conventional boilers, primarily at subcritical steam conditions. A relatively small number of these boilers operate at supercritical steam conditions. The average age of this capacity is in the range of 30-35 years. Increasing numbers of these existing units are being equipped with SO2 and NOx emission control equipment to comply with current emission control regulations. Figure 2 is a simplified sketch of a conventional coal fired power plant. Retrofitting these plants for control of CO2 emissions will be expensive since the concentration of CO2 in the atmospheric pressure product gas is about 14%

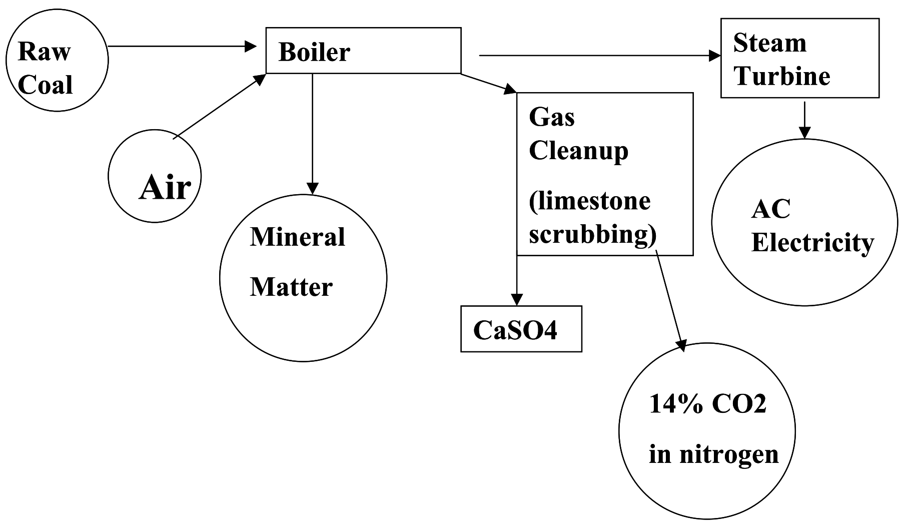

Figure 2. Supercritical Boiler Technology

Integrated Gasification Combined Cycle Power Plants (IGCC)

Integrated Gasification Combined Cycle (IGCC) power plants have long been considered as a potential replacement for conventional coal fired generation since pollutant emissions are much lower because gas cleanup is done on higher pressure streams of gases that contain more concentrated levels of pollutants than the stack gas from coal fired boilers. Figure 3 is a simplified sketch of an IGCC plant. This technology is still early on its learning curve with only 4 plants, each between 250 and 330 MW, now in operation worldwide. The relatively low recent market demand for any type of coal fired plants, coupled with the higher initial capital cost of IGCC plants has precluded significant commercial market penetration as yet.

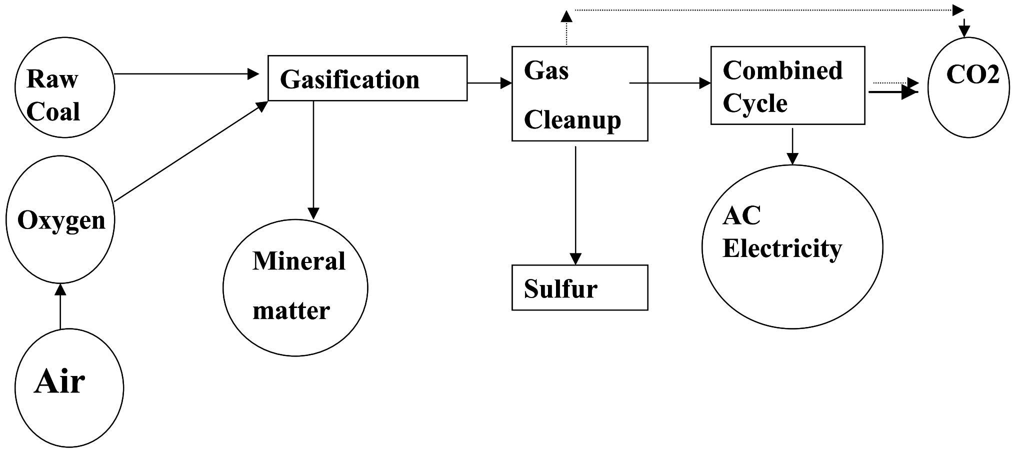

Figure 3. Integrated Gasification Combined Cycle

Impact of CO2 Separation on Conventional Power Production Costs

If CO2 emission controls are implemented, the relative power production costs of the technologies described above change markedly. This is a result of the additional equipment that must be added and the additional power required to operate the additional equipment. In NGCC or SCPC plants, CO2 must be recovered from a dilute stack gas stream at atmospheric pressure. In IGCC plants, CO2 can be removed from the product gas prior to combustion by reacting the fuel gas (a mixture consisting primarily of CO, CO2 and hydrogen) with water to convert the product gas to a mixture of only hydrogen and CO2. The CO2, which is at a high concentration in the pressurized gas stream, is then separated from that mixture and the remaining almost-pure hydrogen is then burned in the turbine, leaving little or no CO2 in the stack gas.

Direct Carbon Fuel Cell Power Plants (DCFC)

Flowsheets previously proposed by LLNL for DCFC power plants, as shown in Figure 4, included carbonization to remove volatile materials from coal. This technology has been used to manufacture coal-derived coke for the steel industry. It is not a particularly clean technology and has many environmental problems, primarily associated with coal tars. The approach previously suggested for dealing with coal tars in a DCFC power plant was to add a pyrolysis system and crack the tars to fuel gas. The fuel gas was then converted to power in another fuel cell

The large number of process steps is likely to result in a power plant that is likely to be both expensive and difficult to operate. These characteristics would make it difficult for DCFC technology to compete in either the distributed generation or central station power markets.

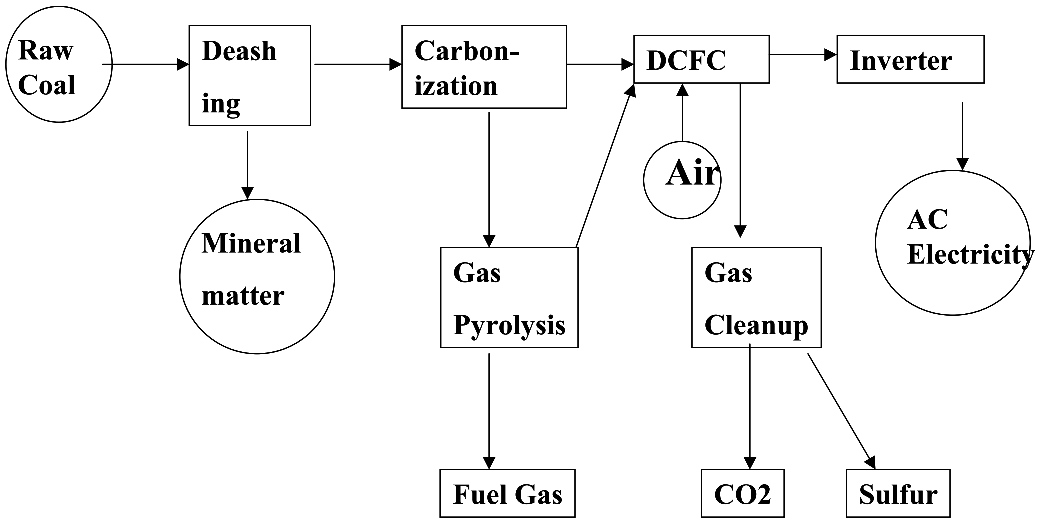

Figure 4. DCFC with deep coal cleaning and external pyrolysis

Figure 5 shows a simplified DCFC power plant where the carbonization and gas pyrolysis steps have been eliminated. However the DCFC for this flowsheet must be designed to cope with any volatile material in the coal-derived feed.

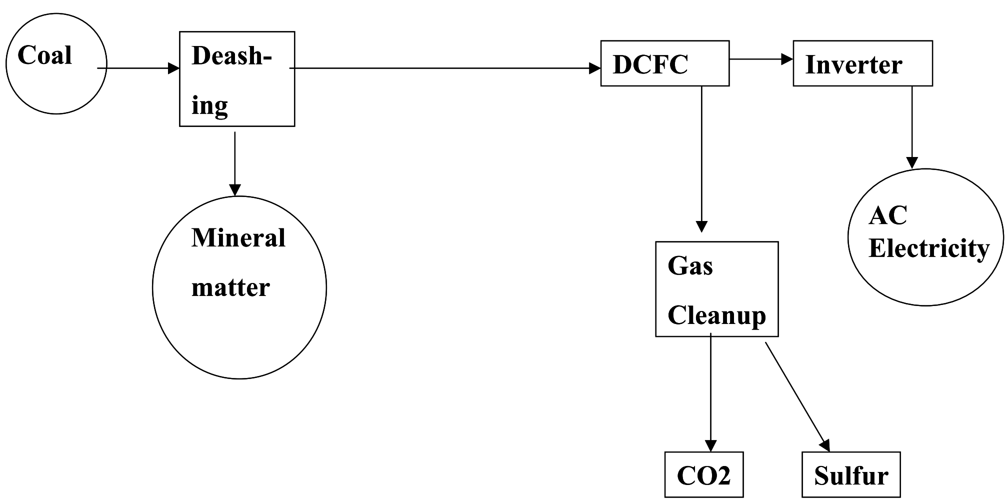

Figure 5. DCFC simplified

One of the key potential advantages of a DCFC power plant is that it would produce an almost pure CO_2 stream from the anode, albeit at atmospheric pressure. This would simplify the gas cleaning system in a power plant. Because of its high efficiency, it also produces about half the CO_2 as conventional coal fired power plants would produce per net MWH of power generated. In comparison with a natural gas combined cycle it would produce about 25% less CO_2, because it will operate at about 75 % HHV efficiency, compared to 55% for the NGCC. Furthermore, it is able to use a solid fuel, which is projected to have a lower overall fuel cost per kWh of electricity produced.

Assessment of Competitiveness

The key question that is addressed by this report is what is the potential relative cost of power from a new, simplified DCFC power plant relative to current fossil-fueled options such as natural gas combined cycle (NGCC), supercritical pulverized coal (SCPC), and Integrated Gasification Combined Cycle (IGCC) power plants. The values used in these calculations for coal to bus bar, Higher Heating Value (HHV) efficiency, total installed plant capital cost fuel costs, O&M costs and approximate added power costs for the addition of sequestration equipment are shown in Table 1. For simplicity the added cost of fuel for these plants where CO2 capture, liquefaction, and pressurization is utilized was not adjusted across the range of fuel prices.

The objective of this exercise was to use a very simple approach to determine where the cost of DCFC produced power would lie relative to currently commercial power generation options. This simple approach was taken due to the very early state of development of the DCFC technology. A very wide range of potential capital costs was used to cover reasonable limits for the assumed installed costs for a DCFC power plant. The lower limit of $400/kW has been set by DOE as the target for its SECA program to develop a low-cost modular Solid Oxide Fuel Cell (SOFC). The upper level of $4000/kW is the current cost of a 200 kW Phosphoric Acid Fuel Cell (PAFC) power plant. Petroleum coke at refineries has a near zero value. The capital cost, efficiencies, O&M costs, and the additional cost for CO2 capture, liquefaction, and pressurization were based on information taken from EPRI Report 1000316 " Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal". The additional cost for sequestration for the DCFC system was assumed at half of that for an IGCC system since both produce a concentrated CO2 stream and the potential overall efficiency of the DCFC system is almost twice that of the IGCC system.

Table 1. Parameter Range for Assessment of Competitiveness of Various Technologies for Commercial Power Production from New Plants

Technology	Efficiency, HHV	Capital Cost, $/kW	Fuel Cost Range, $/MMBTU	O&M ¢/kWh	Additional Cost for CO2 Capture, Liquefaction, and Pressurization ¢/kWh
NGCC	55	550	2 - 7	0.26	2.3
SCPC	40	1280	0 - 2	0.99	3.3
IGCC	45	1420	0 - 2	0.82	1.3
DCFC	75	400-4000	0 - 6	~1	0.7 (Assumed)

Table 2 lists approximate ranges of prices for solid carbon fuels of various types that could be used as fuel for a DCFC system.

Table 2. Solid Carbon Fuel Prices

Fuel	Price, $/MMBTU
Waste carbon black	0+
Petroleum coke	0 - 0.5
Conventionally washed coal	0.75 -1.25
Deeply de-ashed coal	~3
Deeply de-ashed coal and pyrolyzed coal	3++ - 6

Electricity generated on-site to meet the needs of a customer at that site competes against central station power delivered through the T&D grid. The range of T&D charges is usually between 1.5 and 3 ¢/kWh. Figure 6 shows how DCFC power compares with central station power delivered to the same site at T&D charges of 0, 1.5, and 3 ¢/kWh. The 0 ¢/kWh lines are basically there for reference to show the cost of generation at the central station site. In all cases, the plants are assumed to produce power for 7000 hours per year at full rated capacity. The annual capital charges were calculated as 15% of total installed plant cost. Detailed tabulations of these costs are presented in Appendix Tables A.1 through A.4.

From Figure 6, it can be determined that DCFC power generated on-site in plants costing less than about $1700/kW with fuel at $3/MMBtu (as projected for UCC which is discussed later in this report and in Appendix B) would cost about 6 ¢/kWh. This is about the same as the cost of power delivered from central station plants at a T&D cost of 1.5¢/kWh, produced by from SCPC or IGCC plants with a fuel cost of $1/MMBtu, or NGCC plants with a fuel cost of $5/MMBtu. If T&D costs were 3 ¢/kWh for the central station power, their delivered power costs would be 7.5 ¢/kWh, about the same as produced from DCFC plants costing $2400/kW.

It can also be determined from Figure 6 that DCFC power generated on-site in plants costing less than about $1000/kW with fuel at $3/MMBtu (as projected for UCC) would cost about 4.5 ¢/kWh. This is about the same as the cost of power produced at central station SCPC or IGCC plants with a fuel cost of $1/MMBtu, or NGCC plants with a fuel cost of $5/MMBtu. This indicates that for the central station market DCFC power could be competitive if the cost of the DCFC power plant was below about $1000/kWh.

This information is summarized in Table 3.

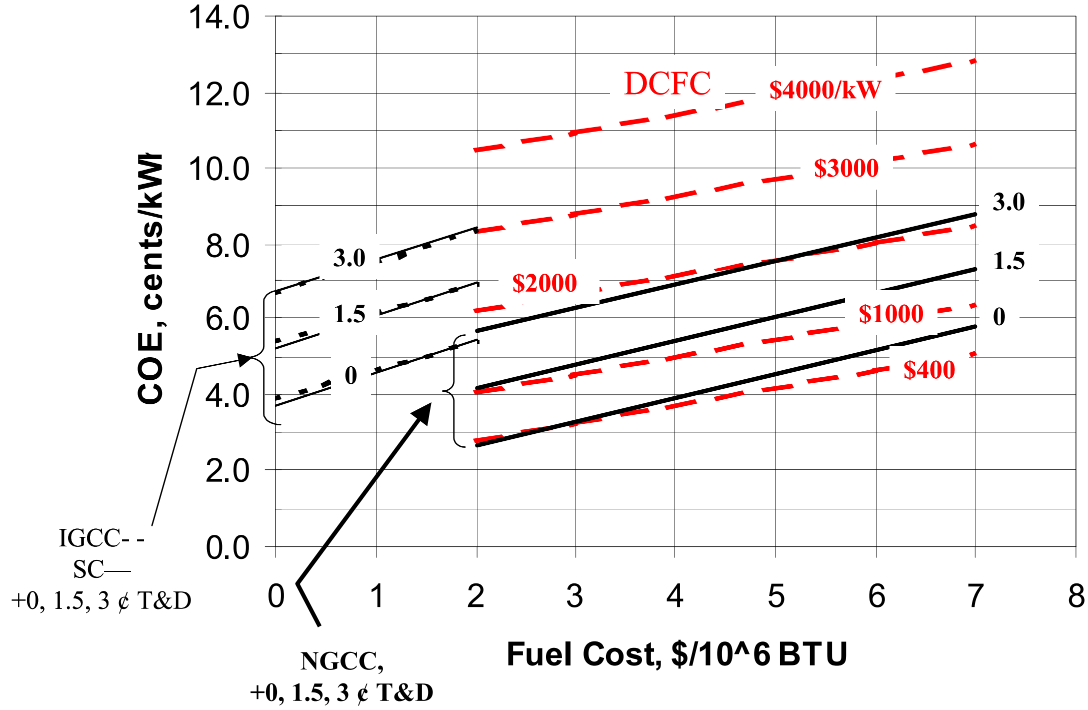

Figure 6. Comparison of Fossil Fuel Generated Power Costs Without CO2 Capture, Liquefaction and Pressurization

Table 3. DCFC Cost Comparison (Without CO2 Capture, Liquefaction and Pressurization)

At about $1700/kW capital cost with $3/MMBTU fuel, newly installed DCFC distributed base load power would be competitive with conventional fossil-fueled central station power when T&D costs are 1.5 ¢/kWh. If T&D costs are 3 ¢/kWh, the allowable DCFC capital cost increases to $2400/kW. If DCFC capital costs were about $1000/kW, DCFC power could compete with other central station plants options, independent of T&D costs

Technology	**Efficiency, HHV**	**Capital Coat, $/kW**	**Fuel Cost. $/MMBtu**	**Electricity, Cost at Power Plant, ¢/kWh**	**Electricity Cost at Power Plant plus 1.5¢/kWh for T&D**	**Electricity Cost at Power Plant plus 3¢/kWh for T&D**
NGCC Central Station	55	550	5	4.54	6.04	7.54
SCPC Central Station	40	1280	1	4.58	6.08	7.58
IGCC Central Station	45	1420	1	4.62	6.12	7.52
DCFC Distributed	75	1000	3	4.52 (Zero T&D)		
DCFC Distributed	75	1700	3		6.02 (Zero T&D)	
DCFC Distributed	75	2400	3			7.52 (Zero T&D)

In those cases being considered for new, future power plants where carbon dioxide capture, liquefaction, and pressurization equipment must be added, the cost of electricity increases, as noted before in Table 1, by 2.3 ¢/kWh for NGCC power plants, 3.3 ¢/kWh for SCPC power plants, and 1.3 ¢/kWh for IGCC power plants. As explained previously, the incremental cost for DCFC power plants has been assumed as 0.7 ¢/kWh. A simplified set of costs was calculated for these cases and the results are plotted in Figure 7.

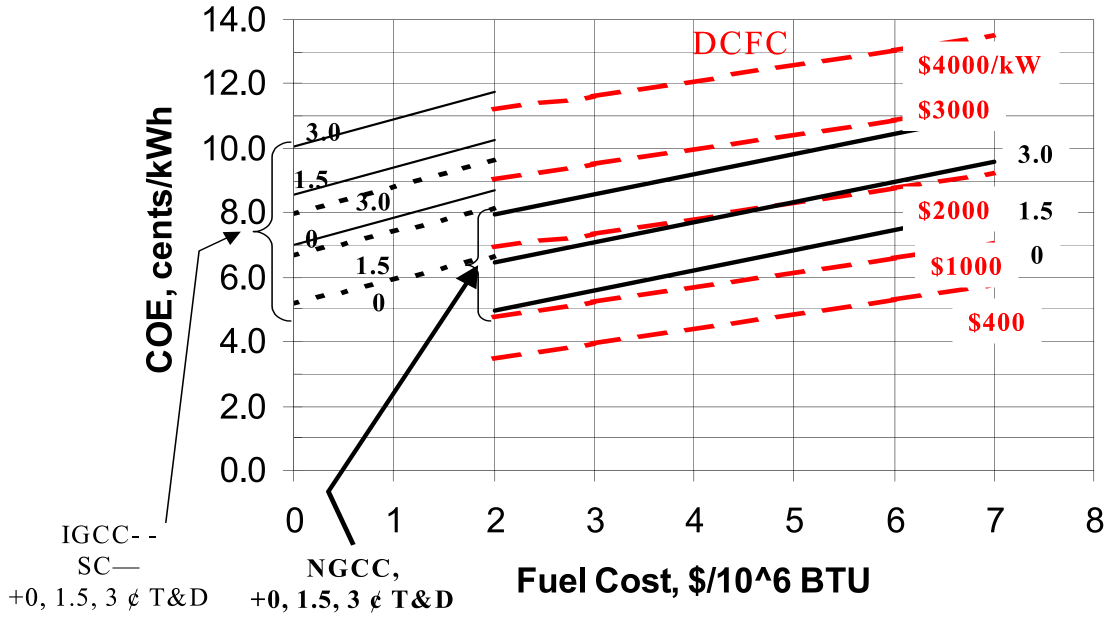

Figure 7. Comparison of Fossil Fuel Generated Power Costs Without CO2 Capture, Liquefaction and Pressurization

From Figure 7, it can be determined that DCFC power generated in a central station plant costing less than about $1300/kW that includes carbon capture, liquefaction, and pressurization with fuel at $3/MMBtu (as projected for UCC) would cost about 5.9 ¢/kWh. This is about the same as the cost of power delivered from a central station plant IGCC with CO2 capture and about 1 ¢/kWh less than power from a NGCC plant with a fuel cost of $5/MMBtu, and 2 ¢/kWh less than power produced from an SCPC plant with a fuel cost of $1/MMBtu, both equipped with CO2 capture equipment.

As noted previously, in the absence of CO2 separation, liquefaction and pressurization, DCFC generated power would have to be produced at 4.5 ¢/kWh to be competitive the cost of generating power in a central station. This required a maximum allowable DCFC cost of about $1000/kW. The requirement for CO2 separation, liquefaction and pressurization, improves the relative competitive position for DCFC and allows the DCFC power plant cost to rise to about $1300/kW to be competitive with the best alternative for central station power production, namely IGCC.

In distributed generation market applications for DCFC power in situations where CO2 separation, liquefaction and pressurization are required, the allowable price for an on-site DCFC power plant increase to \$2000/kW and \$2700/kW respectively if T&D costs are 1.5 and 3 ¢/kWh respectively. Although the cost situation appears more favorable, finding sites for disposal of the CO2 from a distributed power plant is likely to be more difficult since the quantity of CO2 to be moved is far less than from a central station plant and the cost of pipelining it to a distant permanent storage site may be prohibitive. If storage of CO2 from distributed generation sites is required, it is likely that the disposal will have to be either on-site in deep aquifers or unmineable coal seams, or in relatively close formations of the same type. This information is summarized in Table 4.

Table 4. DCFC Cost Comparison With CO2 Capture, Liquefaction and Pressurization

At about \$2000/kW capital cost with \$3/MMBTU fuel, newly installed DCFC distributed base load power would be competitive with conventional fossil-fueled central station power when T&D costs are 1.5 ¢/kWh. If T&D costs are 3 ¢/kWh, the allowable DCFC capital cost increases to \$2700/kW. If DCFC capital costs were about \$1300/kW, DCFC power could compete with other central station plants options, independent of T&D costs

Technology	Efficiency, HHV	Capital Coat, \$/kW	Fuel Cost. \$/MMBtu	Electricity, Cost at Power Plant with CO2 capture, liquefaction and pressurization, ¢/kWh	Electricity Cost at Power Plant with CO2 capture, liquefaction and pressurization, plus 1.5¢/kWh for T&D	Electricity Cost at Power Plant with CO2 capture, liquefaction and pressurization, plus 3¢/kWh for T&D
NGCC Central Station	55	550	5	6.84	8.34	9.84
SCPC Central Station	40	1280	1	7.88	9.38	10.88
IGCC Central Station	45	1420	1	5.92	7.42	8.92
DCFC Distributed	75	1300	3	5.85 (Zero T&D)		
DCFC Distributed	75	2000	3		7.38 (Zero T&D)	
DCFC Distributed	75	2700	3			8.89 (Zero T&D)

Preliminary Conclusions from Simple Economic Analysis

Table 5 presents estimated costs of various plant sections of a complete DCFC power plant. The estimates for the solid fuel feeding, gas clean-up, and CO2 liquefaction and compression were estimated based on information in EPRI Report 1000316. The estimated inverter costs are consistent with those now used in currently offered PAFC and MCFC 200 kW fuel cell power plants.

The purpose of this exercise is to assess what the allowable DCFC plant section power would have to cost to compete with other existing power generation options and to compare that number with the very preliminary estimate of $250/kW developed by LLNL for the cost of the DCFC power plant section.

Table 5. Allowable DCFC Section Costs for A Complete DCFC Power Plants

Case	DCFC Power Plant Without CO2 Capture, Liquefaction, And Pressurization, Estimated Capital Cost, $/kW	DCFC Power Plant With CO2 Capture, Liquefaction, And Pressurization, Estimated Capital Cost, $/kW
Plant Section		
Solid Fuel Feeding and Distribution	50 - 100	50 - 100
Gas Cleanup (sulfur and nitrogen) and CO2 capture	50 - 100	50 - 100
DC to AC Inverter	300 - 400	300 - 400
CO2 Liquefaction and Compression		50 - 100
Total Cost of Balance of Plant for DCFC Power Plant	400 - 600	450 - 700
Allowable capital cost of DCFC section of power plant for distributed generation market if central station power required a 1.5 ¢/kWh T&D charge	1100-1300 (Allowable total DCFC power plant cost = $1700/kW)	1300-1550 (Allowable total DCFC power plant cost = $2000/kW)
Allowable capital cost of DCFC section of power plant for distributed generation market if central station power required a 3 ¢/kWh T&D charge	1800-2000 (Allowable total DCFC power plant cost = $2400/kW)	2000-2250 (Allowable total DCFC power plant cost = $2700/kW)
Allowable DCFC capital cost for central station generation market	400-600 (Allowable total DCFC power plant cost = $1000/kW)	600-850 (Allowable total DCFC power plant cost = $1300/kW)

It appears from this summary that DCFC power plants are very likely to be able to compete in the distributed generation segment of the power market in the range of 5 to 50 MW at industrial sites. If may even be possible for DCDC power plants to compete for the central station market if the DCFC total installed plant costs are <$1000/kW where

CO_2 capture, liquefaction and pressurization are not required and <$1300/kW where they are required. This would limit DCFC section costs to $400-600/kW where CO_2 capture, liquefaction, and pressurization are required and $600-850/kW where they are not required. In all cases, these values for the DCFC section are above the $250/kW currently projected by the LLNL staff as the cost of the DCFC section.

The Key Technical Issues That Must Be Addressed For Potential Commercial Success

The history of fuel cell development is filled with many examples of initial cost projections that were put forward by developers based on their estimates of what the price of their fuel cell product would have to be to compete with other forms of available generation in the markets that they were trying to enter. In the previous section, a summary has been presented of what the allowable fuel cell costs would have to be to enter various markets. This report shows that the projected DCFC section costs appear to be reasonable in terms of competitive market requirements. Furthermore, it appears from that analysis that the most promising market segment to focus on in the near term is the 5-50 MW distributed generation market without considering the issue of CO_2 emission.

The key technical issues can be divided arbitrarily into fuel related and stack related issues. The following discussion is extensive in terms of the fuel related issues and limited to a listing of the stack related issues. Discussions of the latter are best left to LLNL staff.

Fuel Related Issues

Fuel

The preferred feedstock for such a DCFC is a solid carbon free of ash and volatile materials. Activated carbon manufactured from natural gas by pyrolysis reactions can meet these criteria. However, its cost is a strong function of the price of natural gas, which at current levels may limit its utilization to small-scale personal power applications where the value of the electricity is high. Some off-specification activated carbon is produced that only has value as a material that can be blended with on-specification material in a small proportion. This fuel source can support personal power applications, but is too limited for a significant number of distributed power applications for bulk power applications. It has been estimated that there are 1.5 million tons of this material available annually in the US. At a calculated heat rate of 4549 (or 3412/.75) Btu/kWh for a DCFC, and a heat content of 15,000 Btu/pound, this quantity of fuel could be used for about 1800 MW of power at 80% capacity factor. This is small compared to the approximately 300,000 MW of coal fired generation capacity currently in place.

Petroleum coke, which has no volatile material, contains on average a total of about 2000 ppm (0.2 wt%) of vanadium plus nickel along with much smaller amounts of iron and other metallic elements. Annual production in the US is over 30 million tons and would support about 36,000 MW of DCFC generation using the same criteria that were used for the carbon black case above. This could replace about 10% of the current coal fired fleet of about 300,000 MW.

This leaves coal as the most likely important source of fuel if a significant market for DCFC power plants develops. However coal contains a significant amount of ash, usually about 10% or less after normal washing at the coal production site, and a significant amount of volatile material. Pretreatment of coke can minimize both the ash and volatile matter. However, this has a significant cost associated with it.

The preferred coal-derived feedstock for this DCFC is a deeply de-ashed coal with an ash content of less than 0.5 wt% and preferably below 0.1 wt% to lengthen the period between having to reprocess the electrolyte to remove the ash. It has been assumed that electrolyte impurities can build up to 10% before reprocessing is thought to be necessary. With an ash content of less than 0.1 wt% in the feed coal, the electrolyte reprocessing cycle would be on a cycle of approximately 900 days.

LLNL previously published conceptual flowsheets for a DCFC system that included both deashing and pyrolysis steps to remove volatile matter. It has recently proposed to the LLNL team that they consider simplifying the flowsheet by eliminating the pyrolysis step and redesigning the system so that all the coal including the volatile matter can be converted in the fuel cell. A deeply de-ashed coal, containing about 0.1 wt% ash was obtained from the UltraClean Coal (UCC) development program in Australia. Initial results are reportedly very promising. Appendix B contains a flowsheet of the UCC process (Figure B-1), which involves caustic leaching to remove ash, and information about the composition of the product (Table B-1). The target price of UCC is about $3/MMbtu. Other deeply de-ashed coals, with ash contents of 0.5 wt.% can be obtained by other physical (deep hydraulic cleaning – University of Kentucky Coal and Energy Research Center) and chemical cleaning (CENfuel acid leaching) processes at costs that are also estimated to be about the same of UCC.

Feedstock Distribution

Each fuel cell must be fed at least periodically, but not necessarily continuously, with a supply of fresh carbon. If the feed contains volatile matter as it does when coal is the feedstock, it must be removed prior to feeding to the cell or able to be processed within the cell. The concern is that the volatile matter that is liberated from the coal as it heats up within the cell will condense on the cooler feed coal in another part of the feed system, causing particles of coal to agglomerate and interfering with steady feeding of coal to the cell.

This is one of the design challenges that must be overcome. Mild oxidation of the coal has been shown to markedly reduce the amount of volatile material liberated from coal. Experimental confirmation of ability to feed the cell without agglomeration in the feed system is required.

Anode Gas Processing

The anode gas is primarily CO2 along with sulfur and nitrogen compounds. The issue with the CO2 leaving the fuel cell is that it passes through at least part of the bed of carbon that is being fed to the cell. Control of temperature and time within this zone is necessary to avoid the Boudouard reaction where CO2 reacts with carbon to produce carbon monoxide. It should be noted that in the small scale, single cell experiments that have been done to date that the product gases are very low in CO.

The other issue that removal of sulfur containing compounds (COS, H2S, etc) and nitrogen containing compounds other than N2 (i.e. NH3, HCN, etc.) in a primarily CO2 stream remain to be worked out. It is likely that such a scheme can be developed using combinations of existing technology. One of the approaches that has been considered of hydrolyzing COS with H2O to H2S may be equilibrium limited because of the presence of a high concentration of CO2 in that stream, which is one of the reaction products.

DCFC Stack Related Issues

- Cell area scaleup
- Heat removal
- Fuel contact over entire current collector surface
- Fuel wetting by electrolyte
- Performance degradation as a result of electrolyte contamination
- Electrolyte purification and re-injection processes
- Cathode identity and performance

Technology Milestones That Need to be Accomplished Over the Next One to Two Years

There are several items of experimental work and process engineering that need to be accomplished in the near-term to support future development of DCFC technology.
It is important to identify the sulfur and nitrogen compounds present in the anode gas product and to close the material balance around the current small-scale experimental cell. This information is needed to support a process engineering analysis to define the requirements for a product gas clean-up system. That system is likely to require several steps to remove sulfur and nitrogen compounds to required levels.

There are a number of initial scale-up developments that are necessary to ensure that the program is credible in terms of eligibility for any significant amount of demonstration program funding. These include:

- Multi-cell demonstration (three or more cells)
- Multi-cell demonstration with periodic fuel recharging – 100 hours continuous operation to show that the fuel system will not plug up

- Multi-cell demonstration with periodic fuel recharging -- 1000 hours continuous operation to demonstrate a reasonable voltage decline rate
- Electrolyte purification and recharging

DOE Position Relative to DCFC

Over the past few years DOE has sponsored some exploratory work to investigate various aspects of science related to DCFC. However, the primary current emphasis in the DOE fuel cell program is on SECA, the Solid-state Energy Conversion Alliance. The objective of the SECA program is the development of modular, 5 kW, SOFC fuel cells with a targeted cost of $400/kW. The FY04 SECA budget is $46 million. DOE's total budget request for FY05 for all of its fuel cell program is $23 million, which is only half on what it is spending on SECA alone in FY04.

With the current major commitment to the SECA program, DOE is unwilling to commit to another major fuel cell development program at this time. Their position is that they will be willing to consider funding the scale-up of DCFC technology only after a 1 kW prototype has been successfully demonstrated and a complete economic analysis has been performed under the sponsorship of other entities.

Conclusions

- The small-scale, single-cell experimental program to date has confirmed that DCFC electrochemistry completely converts solid carbon fuel by reaction with air to CO2 and electricity with 75-80% efficiency

- Preliminary and relatively simplistic economic analysis indicates that the cost of the DCFC section of the power plant projected by LLNL is much lower than would be required for DCFC power plants to be competitive for the small industrial plant distributed power generation market of 5-50 MW.

- That same type of analysis indicates that if CO2 emissions are implemented, then DCFC technology is more likely to become competitive for central station applications.

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APPENDICES

Appendix A

Table A-1 Cost of Electricity - Natural Gas Combined Cycle Central Station Power Plant

Assumptions
- 55% efficiency (HHV)
- Base load operation, 80% capacity factor (7000 hours per year)
- \$550/kW installed capital cost
- 15% cost of capital, 1.18cent/kWh capital charges
- 0.26 cent/kWh O&M cost

Fuel cost, \$/MMBtu	Fuel charges, ¢/kWh	O&M charges, ¢/kWh	Capital charges, ¢/kWh	Total electricity cost at power plant, ¢/kWh	Plus 1.5 ¢/kWh added for T&D	Plus 3 ¢/kWh added for T&D
2	1.24	0.26	1.18	2.68	4.18	5.68
3	1.86	0.26	1.18	3.30	4.80	6.30
4	2.48	0.26	1.18	3.92	5.42	6.92
5	3.10	0.26	1.18	4.54	6.04	7.54
6	3.72	0.26	1.18	5.16	6.66	8.16
7	4.34	0.26	1.18	5.78	7.28	8.78

Table A-2 Cost of Electricity - Supercritical Pulverized Coal Fired Central Station Power Plant

Assumptions
- 40% efficiency (HHV)
- Base load operation, 80% capacity factor (7000 hours per year)
- \$1280/kW installed capital cost
- 15% annual cost of capital = 2.74 ¢/kWh capital charges
- 0.99 ¢/kWh O&M cost

Fuel cost, \$/MMBtu	Fuel charges, ¢/kWh	O&M charges, ¢/kWh	Capital charges, ¢/kWh	Total electricity cost at power plant, ¢/kWh	Plus 1.5 ¢/kWh added for T&D	Plus 3 ¢/kWh added for T&D
0	0	0.99	2.74	3.73	5.23	6.73
0.5	0.43	0.99	2.74	4.16	5.66	7.16
1	0.85	0.99	2.74	4.58	6.08	7.58
2	1.70	0.99	2.74	5.43	6.93	8.43

Table A-3 Cost of Electricity - IGCC Central Station Power Plant

Assumptions

- 45% efficiency (HHV)
- Base load operation, 80% capacity factor (7000 hours per year)
- $1420/kW installed capital cost
- 15% annual cost of capital = 3.04 ¢/kWh capital charges
- 0.82 ¢/kWh O&M cost

Fuel cost, $/MMBtu	Fuel charges, ¢/kWh	O&M charges, ¢/kWh	Capital charges, ¢/kWh	Total electricity cost at power plant, ¢/kWh	With 1.5 ¢/kWh added for T&D	With 3 ¢/kWh added for T&D
0	0	0.82	3.04	3.86	5.36	6.86
0.5	0.38	0.82	3.04	4.24	5.74	7.24
1	0.76	0.82	3.04	4.62	6.12	7.62
2	1.52	0.82	3.04	5.38	6.88	8.38

Table A-4 DCFC Electricity Cost

Assumptions

- 75% efficiency (HHV)
- Base load operation, 80% capacity factor (7000 hours per year)
- \$400/kW installed capital cost – 15% annual cost of capital = 0.86 ¢/kWh capital charges
- \$1000/kW installed capital cost --15% annual cost of capital = 2.14 cent/kWh capital charges
- \$2000/kW installed capital cost --15% annual cost of capital = 4.29 cent/kWh capital charges
- \$3000/kW installed capital cost --15% annual cost of capital = 6.43 cent/kWh capital charges
- 1 cent/kWh O&M cost

Fuel cost, \$/MMBtu	Fuel Charges, ¢/kWh	O&M charges, ¢/kWh	Capital cost, \$/kW	Capital charges, ¢/kWh	Total electricity cost at power plant, ¢/kWh
1	0.45	1	400	0.86	2.31
1	0.45	1	1000	2.14	3.59
1	0.45	1	2000	4.29	5.74
1	0.45	1	3000	6.43	7.88
1	0.45	1	4000	8.57	9.93
2	0.91	1	400	0.86	2.77
2	0.91	1	1000	2.14	4.05
2	0.91	1	2000	4.29	6.20
2	0.91	1	3000	6.43	8.34
2	0.91	1	4000	8.57	10.48
3	1.38	1	400	0.86	3.24
3	1.38	1	1000	2.14	4.52
3	1.38	1	2000	4.29	5.67
3	1.38	1	3000	6.43	8.81
3	1.38	1	4000	8.57	10.95
6	2.76	1	400	0.86	4.62
6	2.76	1	1000	2.14	5.90
6	2.76	1	2000	4.29	8.05
6	2.76	1	3000	6.43	10.19
6	2.76	1	4000	8.57	12.35

Appendix B

Figure B-1. Simplified Flowsheet of the Ultra-clean Coal (UCC) Process – Caustic Digestion of Coal Mineral Matter

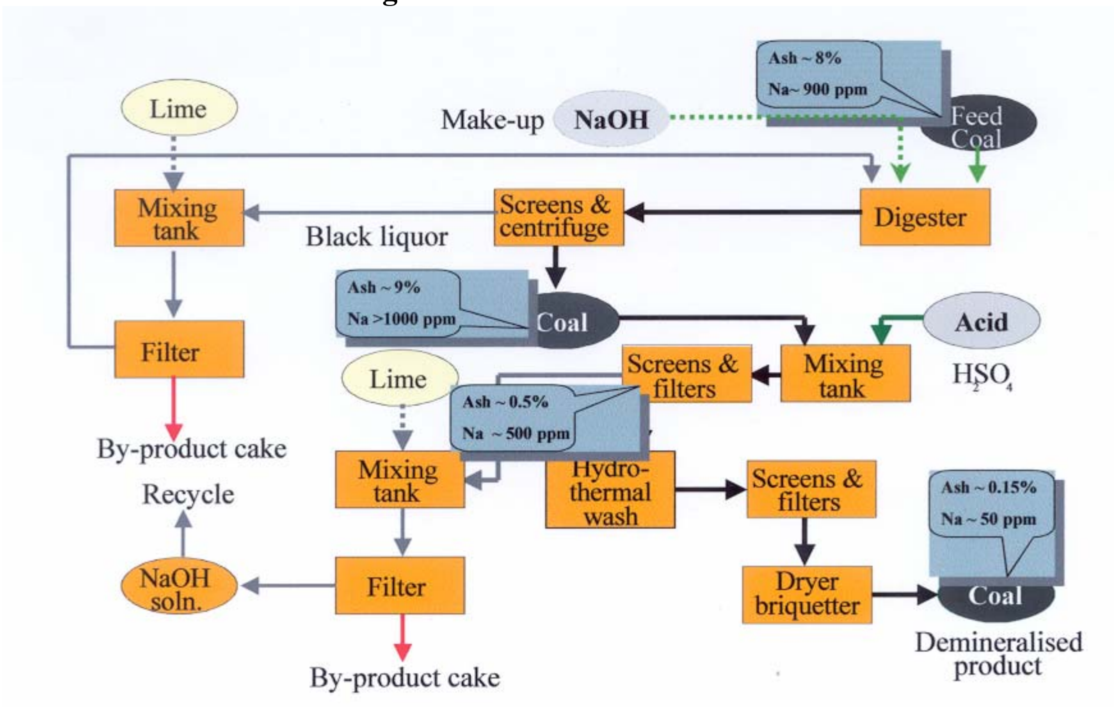

Table B-1. Typical UCC Contaminants

Property	**Feed Coal**	**UCC 1998**	**UCC Current**
Total Ash, weight %	8.3	0.5	0.08 - 0.14
Ash Particle Size		<5µm	<5µm
Inorganic content of the coal, ppm			
Si	24,800	78	35
Al	12,300	~0	8
Ti	733	513	477
Fe	3,383	215	34
Ca	437	36	22
Mg	431	12	5
Na	919	542	58
K	464	29	9
P	86	6	3
Mn	13	1	0
V	29	7	12
Ash Fusion Temperature, IDT	>1500°C	1240°C	>1500°C

Reference: Keith Clark, John Langley, Shigeki Sasahara, Mitsuru Inada, Tory Yamashita, and Yokitoshi Kozai; ***Ultra Clean Coal as a Gas Turbine Fuel***