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A Total Cost of Ownership Model for Low Temperature PEM Fuel Cells in Combined Heat and Power and Backup Power Applications

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DISCLAIMER

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Executive Summary

A total cost of ownership model (TCO) is described for emerging applications in stationary fuel cell systems. Low temperature proton exchange membrane (LT PEM) systems for use in combined heat and power applications from 1 to 250 kilowatts-electric (kWe[1]) and backup power applications from 1 to 50 kWe are considered. The total cost of ownership framework expands the direct manufacturing cost modeling framework of other studies to include operational costs and life-cycle impact assessment of possible ancillary financial benefits during operation and at end-of-life. These include credits for reduced emissions of global warming gases such as carbon dioxide (CO_2) and methane (CH_4), reductions in environmental and health externalities, and end-of-life recycling. This report is an updated revision to the earlier 2014 LBNL report [1].

System designs and functional specifications for LT PEM fuel cell systems for back-up power and co-generation applications were developed across the range of system power levels above. Bottom-up cost estimates were made based on currently installed fuel cell systems for balance of plant (BOP) costs, and detailed evaluation of design-for-manufacturing-and-assembly[2] (DFMA) costs was carried out to estimate the direct manufacturing costs for key fuel cell stack components. The costs of the fuel processor subsystem are also based on an earlier DFMA analysis [2]. The development of high throughput, automated processes achieving high yield are estimated to push the direct manufacturing cost per kWe for the fuel cell stack to nearly $200/kWe at high production volumes. Overall direct system costs including corporate markups and installation costs are about $3800/kWe ($1800/kWe) for 10kW (100kW) CHP systems at 50,000 systems per year, and about $1100/kWe for 10kWe backup power systems at 50,000 systems per year. The updated values for system costs are within 10% of the 2014 report, but this overall similar cost result is derived from lower estimated stack costs and higher balance of plant costs.

At high production volume, material costs dominate the cost of fuel cell stack manufacturing. Based on these stack costs, we find that BOP costs (including the fuel processor) dominate overall system direct costs for CHP systems and are thus a key area for further cost reduction. For CHP systems at low power, the fuel processing subsystem is the largest cost contributor of total non-stack costs. At high power, the electrical power subsystem is the dominant cost contributor.

Life-cycle or use-phase modeling and life cycle impact assessment (LCIA) were carried out for regions in the U.S. with high-carbon intensity electricity from the grid. In other regions, TCO costs of fuel cell CHP systems relative to grid power exceed prevailing commercial power rates at the system sizes and production volumes studied here. Including total cost of ownership credits can give a net positive cash flow in Minneapolis and Chicago for fuel cell CHP systems in small hotels. We find this to be true for a static grid with unchanging grid emission factors, and also for a cleaner grid out to 2030 subject to federal regulations such as the EPA's Clean Power Plan. TCO costs for fuel cell CHP systems are dependent on several factors such as the cost of natural gas, utility tariff structure, amount of waste heat utilization, carbon intensity of displaced electricity and conventional heating, carbon price, and valuation of health and environmental externalities. Quantification of externality damages to the environment and public health utilized earlier environmental impact assessment work and datasets available at LBNL.

Overall, this type of total cost of ownership analysis quantification is important to identify key opportunities for direct cost reduction, to fully value the costs and benefits of fuel cell systems in stationary applications, and to provide a more comprehensive context for future potential policies.

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[1] In this report, units of kWe stand for net kW electrical power unless otherwise noted.

[2] DFMA is a registered trademark of Boothroyd, Dewhurst, Inc. and is the combination of the design of manufacturing processes and design of assembly processes for ease of manufacturing and assembly and cost reduction.

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1 Introduction

Stationary fuel cells have various advantages compared to conventional power sources, with high electrical efficiency and extremely low criteria pollutants (if fed with hydrocarbons) or even zero emissions (if fed with pure hydrogen). If fuel cells become widely available they could displace fossil-fuel powered plants and improve public health outcomes due to the reduction of air pollutants such as fine particulate matter from coal-fired plants, and they might also displace nuclear plants and avert the disposal issues associated with nuclear waste.

Existing and emerging applications include primary and backup power, combined heat and power (CHP), materials handling equipment applications such as forklifts and palette trucks (MHE), and auxiliary power applications.

Despite this, stationary fuel cell systems are not deployed in high volumes today because of high initial capital costs and lack of familiarity with hydrogen as a fuel source, although MHE and backup power systems deployments are in the thousands.

In the last years the Department of Energy (DOE) has commissioned several cost analysis studies for fuel cell systems for both automotive [3,4] and non-automotive systems [5,6]. While many cost studies and cost projections as a function of manufacturing volume have been done for automotive fuel cell systems, fewer cost studies have been done for stationary fuel cells.

The limited studies available have primarily focused on the manufacturing costs associated with fuel cell system production. This project expands the scope and modeling capability from existing direct manufacturing cost modeling in order to quantify more fully the broader economic benefits of fuel cell systems by taking into account life cycle assessment, air pollutant impacts and policy incentives. The full value of fuel cell systems cannot be captured without considering the full range of Total Cost of Ownership (TCO) factors. TCO modeling becomes important in a carbon-constrained economy and in a context where health and environmental impacts are increasingly valued.

This report provides TCO estimates starting with the direct manufacturing cost modeling results for CHP systems in the 1 to 250 kWe range and for backup power systems in the 1 to 50 kWe range for low temperature proton exchange membrane-based (LT PEM) systems (Table 1-1), including a detailed breakdown of fuel cell stack, balance-of-plant, and fuel subsystem component costs. CHP systems assume reformate fuel and backup power systems assume direct H_2 fuel. Life-cycle costs of CHP systems are estimated for various commercial buildings in different geographical regions of the U.S. Health and environmental impact assessment is provided for fuel cell-based CHP systems compared to a baseline of grid-based electricity and fossil fuel-based heating (e.g., natural gas, fuel oil, wood, etc., or some combination thereof). This is not meant to be a market penetration study, although promising CHP market regions of the country are identified. Rather, the overriding context is to assume that this market is available to fuel cell systems and to address what range of costs can be achieved and under what assumptions.

Table 1-1 Application space for this work. CHP and backup power are studied at various production volumes and system sizes.

APPLICATION	SIZE [KW]	PRODUCTION VOLUME (UNITS/YEAR)			
		100	1000	10,000	50,000
Combined Heat and Power (CHP)	1	x	x	x	x
	10	x	x	x	x
	50	x	x	x	x
	100	x	x	x	x
	250	x	x	x	x

APPLICATION	SIZE [KW]	PRODUCTION VOLUME (UNITS/YEAR)			
		100	1000	10,000	50,000
BACKUP POWER	1	x	x	x	x
	10	x	x	x	x
	25	x	x	x	x
	50	x	x	x	x

Detailed cost studies provide the basis for estimating cost sensitivities to stack components, materials, and balance-of-plant components and identify key cost component limiters such as platinum loading. Other key outputs of this effort are manufacturing cost sensitivities as a function of system size and annual manufacturing volume. Such studies can help to validate DOE fuel cell system cost targets or highlight key requirements for DOE targets to be met. Insights gained from this study can be applied toward the development of lower cost, higher volume-manufacturing processes that can meet DOE combined heat and power system equipment cost targets.

1.1 Technical targets and technical barriers

For stationary applications, DOE has set several fuel cell system cost and performance targets. For example, for residential combined heat and power in the 10 kWe size, equipment cost in 2020 should be below $1700/kWe, electrical generation efficiency of greater than 45%, durability in excess of 60,000 hours and system availability at 99%. A summary of equipment cost targets for natural gas based systems is shown in Table 1-2. Note that the targets in Table 1-2 are for equipment costs but do not include installation costs.

Table 1-2 DOE multiyear plan system equipment cost targets

System Type	2015 Target	2020 Target
10 kWe CHP System	$1900/kWe	$1700/kWe
100-250 kWe, CHP System	$2300/kWe	$1000/kWe

1.2 Emerging applications

The key markets for this study are combined heat and power applications, and backup power installations. Cost, system reliability and system utilization are key drivers. Recent studies have highlighted backup power systems and material handling systems as key market opportunities [7].

Depending on energy costs and policy environments, there may be opportunities for micro-CHP as well, for example in large expensive homes in cold climates. Cogeneration of power and heat for commercial buildings may be another opportunity, and has been highlighted as a market opportunity for California commercial buildings [6].

Internationally, stationary fuel cell systems are enjoying an increase in interest with programs in Japan, South Korea and Germany but all markets are still at a cost disadvantage compared to incumbent technologies. Japan has supported residential fuel cell systems of 0.7-1 kWe for co-generation with generous subsidies, and the recent nuclear reactor accident in Fukishima has prompted consideration of a range of hydrogen powered systems as alternatives to nuclear energy.

1.3 Total cost of ownership modeling

This work estimates the total cost of ownership (TCO) for emerging fuel cell systems manufactured for stationary applications. The TCO model includes manufacturing costs, operations and end of life disposition, life cycle impacts, and externality costs and benefits. Other software tools employed include commercially available Boothroyd Dewhurst DFMA software, existing LCA database tools, and LBNL exposure and health impact models. The overall research and modeling approach is shown in Figure 1-1.

The approach for direct manufacturing costs is to utilize Design for Manufacturing and Assembly (DFMA) techniques to generate system design, materials and manufacturing flow for lowest manufacturing cost and total cost of ownership. System designs and component costs are developed and refined based on the following: (1) existing cost studies where applicable; (2) literature and patent sources; (3) industry and national laboratory advisors.

Life-cycle or use-phase cost modeling utilizes existing characterization of commercial building electricity and heating demand by geographical region. Life cycle impact assessment (LCIA) is focused on use-phase impacts from energy use, carbon emissions and pollutant emissions—specifically on particulate matter (PM) emissions since PM is the dominant contributor to life-cycle health impacts. Health impact from PM is characterized using existing health impact models available at LBNL. Life-cycle impact assessment is characterized as a function of fuel cell system adoption by building type and geographic location. This approach allows the quantification of externalities (e.g. CO_2 and particulate matter) for FC system market adoption in various regions of the U.S.

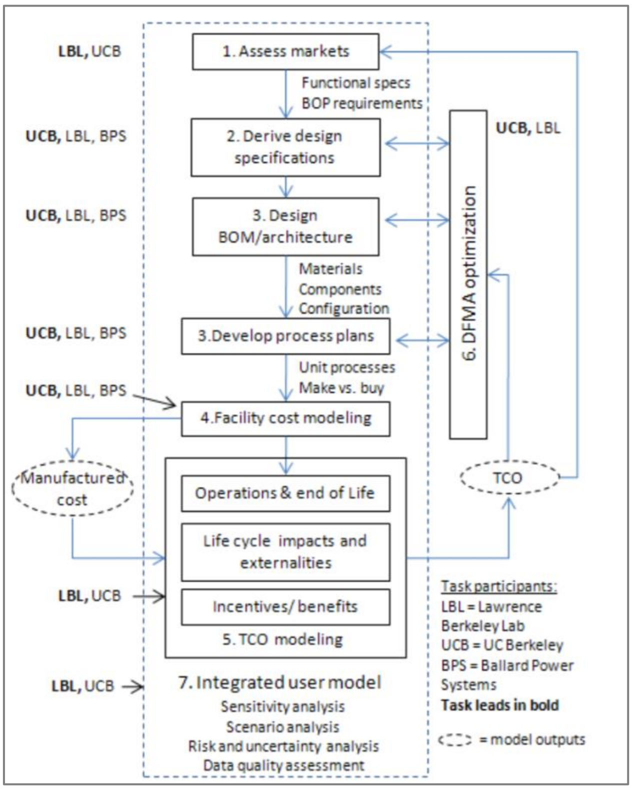


Figure 1-1 Research and modeling approach

1.3.1 Other FC applications

Fuel cells, in addition to the stationary and backup power generation applications that we will analyze in detail in this project also have other important applications. The PEM FC is a prime candidate for vehicle and other mobile applications of all sizes down to mobile phones, because of its compactness.

Much work has been done in the past to investigate and project the utilization of FC in the passenger vehicle sector to replace the combustion engine as a power producer. The development of fuel cell vehicles (fuel cells with an electric motor) is a very active area today among automotive companies, employing huge resources. Hyundai's hydrogen-powered car, Hyundai's ix35 Fuel Cell, has been on the market since 2014, and Toyota unveiled their hydrogen-powered car, the Mirai, the same year. Honda, Volkswagen, Mercedes, Audi, and BMW are other well-known car brands that are said to be pursuing hydrogen fuel cell vehicles as well [8].

PEM FCs for buses, which use compressed hydrogen for fuel, can operate at up to 40% efficiency. Generally PEM FCs can be attractive to implement on buses because of the available volume to house the system and store the fuel.

2 System Design and Functional Specifications

For this project LTPEM FC system design and functional specifications have been developed for a range of systems sizes including CHP systems with reformate fuel in the range of 1-250 kW, and backup power systems from 1kW to 50 kW utilizing direct H_2 fuel. These data come from available data in literature, from industrial specification sheets and from industry advisor inputs.

2.1 CHP system design

Figure 2-1 illustrates PEM FC system design for CHP application, and this reference scheme is used to develop the costing analysis of this project. The CHP systems are subdivided into subsystems as follows: (1) fuel cell stack, (2) fuel supply system, (3) air supply, (4) water makeup loop, (5) coolant system, (6) power conditioning, (7) controls and meters, and (8) ventilation air supply. In this reference scheme all the components are thermally integrated and the inlet and outlet streams are coupled in order to recover the energy of the exhausts and increase the efficiency of the system (both thermal and electrical).

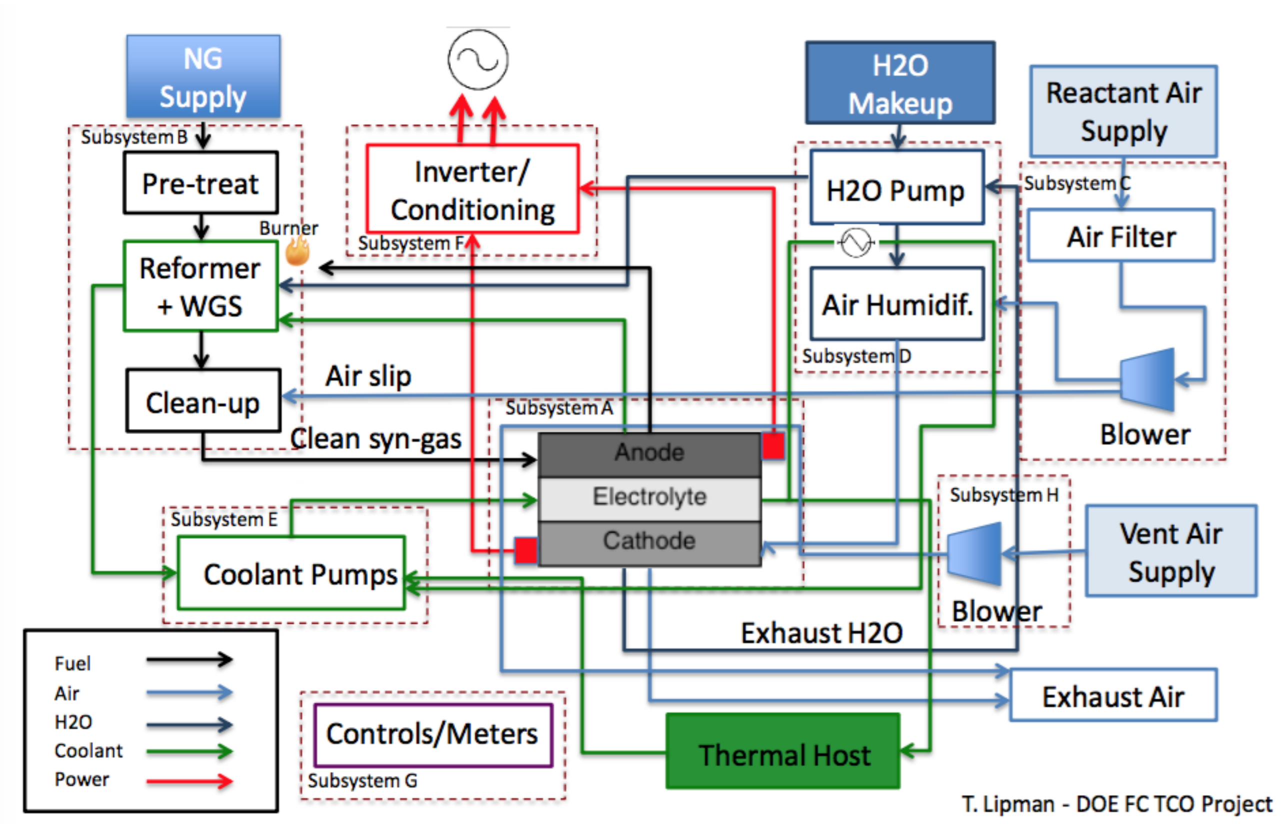


Figure 2-1 System design for CHP system using reformate fuel

2.2 CHP functional specifications

Functional specifications for the 1, 10, 50, 100, and 250kWe CHP systems with reformate fuel are shown in Tables 2-1 and 2-2. These functional specifications are developed based on a variety of industry sources and literature and include calculated parameters for stack and system efficiencies for an internally consistent set of reference values.

The determination of gross system power reflects about 28% overall parasitic power at 10 kWe and about 24% at 100 kWe, including losses through the inverter. DC to AC inverter efficiency is assumed to be 93% and constant across the system power ranges. Additional parasitic losses are from compressors, blowers and other parasitic loads and are assumed to be direct DC power losses from the fuel cell stack output power.

Table 2-1 Functional specifications for 1, 10, 50 kWe CHP fuel cell system operating on reformate fuel

Parameter	1 kWe CHP system with reformate fuel	10 kWe	50 kWe	Units
Gross system power	1.30	12.8	63.3	kWe
Net system power	1	10	50	kWe
Electrical output	110V AC	480V AC	480V AC	Volts AC or DC
DC/AC inverter efficiency	93	93	93	%
Waste heat grade	65	65	65	Temp. °C
Fuel utilization % (overall)	95	95	95	%
Net electrical efficiency	31	32	32	% LHV
Thermal efficiency	49	49	50	% LHV
Total efficiency	80	81	82	Elect.+thermal (%)
Stack power	1.30	12.8	10.54	kWe
Total plate area	360	360	360	cm^2
CCM coated area	259	259	259	cm^2
Single cell active area	220	220	220	cm^2
Gross cell inactive area	39	39	39	%
Cell amps	109	111	111	A
Current density	0.49	0.50	0.50	A/cm^2
Reference voltage	0.7	0.7	0.7	V
Power density	0.346	0.353	0.352	W/cm^2
Single cell power	76.2	77.8	77.5	W
Cells per stack	17	164	136	cells
Stacks per system	1	1	6	stacks
Parasitic loss	0.22	2	9.5	kWe

Table 2-2 Functional specifications for 100 and 250 kWe CHP fuel cell system operating on reformate fuel

Parameter	100 kWe	250 kWe	Units
Gross system power	124	309	kWe
Net system power	100	250	kWe
Electrical output	480V AC	480V AC	Volts AC or DC
DC/AC inverter efficiency	93	93	%
Waste heat grade	65	65	Temp. °C
Fuel utilization % (overall)	95	95	%
Net electrical efficiency	32.8	33	% LHV
Thermal efficiency	50	52	% LHV
Total efficiency	83	85	Elect.+thermal (%)
Stack power	9.50	9.36	kWe
Total plate area	360	360	cm^2
CCM coated area	259	259	cm^2
Single cell active area	220	220	cm^2
Gross cell inactive area	39	39	%
Cell amps	111	111.4	A
Current density	0.51	0.51	A/cm^2
Reference voltage	0.7	0.7	V
Power density	0.354	0.354	W/cm^2
Single cell power	77.9	78	W
Cells per stack	122	120	cells
Stacks per system	13	33	stacks
Parasitic loss	16.0	40	kWe

The waste heat grade from the coolant system is taken to be 65°C for all system sizes. At the reference cell voltage of 0.7 volts, the net electrical efficiency is 32-33% (LHV) for the reformate systems. These overall electrical efficiency levels are similar to those reported in the literature [9]. Fuel reformer efficiency is estimated to be 75%. The total overall efficiency of 81-83% is viewed as a benchmark value for the case where a large reservoir of heat demand exists and represents the maximal total efficiency of the system. Actual waste heat utilization and total efficiency will be highly dependent on the site and heating demands.

There is a well-documented trade-off of peak power and efficiency. The functional specifications are defined for operation at full rated power. Moving away from the peak power point to lower current density, the cell voltage increases and thus the stack efficiency improves. Partial load operation has higher efficiency but less power output. For the LT PEM technology considered here, the system is assumed to be load following, or capable of ramping its power level up and down to follow electrical demand.

Total fuel cell plate area is taken to be 360 cm^2 based on inferences and interpretation of publically available industry spec sheets. Catalyst-coated membrane area is about 72% of this area due to plate border regions and manifold openings. Single cell active area has an additional 15% area loss. As described further in the DFMA costing section below, this is due to the overlap and alignment area loss associated with the frame sealing process and is a conservative estimate for area loss assumed for system reliability.

2.3 System and component lifetimes

Table 2-3 summarizes system and component lifetime assumptions for PEM FC CHP application in the near-term and in the future.

Table 2-3 Specifications for PEM CHP system

CHP Application - PEMFC	Near-Term	Future	
System life	15	20	years
Stack life	20,000	40,000	hours
Reformer life (if app.)	5	10	years
Compressor/blower life	7.5	10	years
Water management subsystem life	7.5	10	years
Battery/startup system life	7.5	10	years
Turndown ratio	3 to 1	3 to 1	ratio
Expected Availability	96	98	percent
Stack cooling strategy	Air+off gas	Air+off gas	cooling

System life is assumed to be approximately 15 years currently and anticipated to increase to 20 years in the future. Stack life is 20,000 hours in the near term and projected to double to 40,000 hours per industry and DOE targets. Subsystem component lifetimes vary from 5-10 years, with somewhat longer lifetimes expected in the future compared with the present.

The system turndown ratio is defined as the ratio of the system peak power to its lowest practical operating point (e.g., operation at 33 kWe on a 100 kWe system is a turndown ratio of 3 to 1).

3 Costing Approach and Considerations

This section presents the costing approach used in this study and is derived from the 2014 LBNL report [1]. Figure 3-1 provides a schematic description of the costing approach. The starting point is system definition and identification of key subsystems and components. The costing approach of the fuel cell systems starts with the system definition and identification of the key subsystems and components. In this phase is important to determine the functional specifications of the fuel cell because these parameters are key inputs to the costing model. For example the power density determines the surface area that is needed to obtain a certain power and thus is directly related to the material cost of the cell.

Manufacturing strategy is then defined to determine which components to purchase and which to manufacture in-house. One informal criterion for purchasing components is whether or not there is an "active market" of buyers and sellers for the component. For example, an active market might be defined as one in which there are at least three suppliers and three purchasers, and one in which suppliers do not have undue market power or monopoly power.

Total annualized manufacturing cost is the sum of process cost per module plus required labor and required materials and consumable materials. One of the main objectives of this analysis is to determine the relative manufacturing costs of materials, versus investment and other cost components as a function of various system sizes and as a function of varying annual production volume.

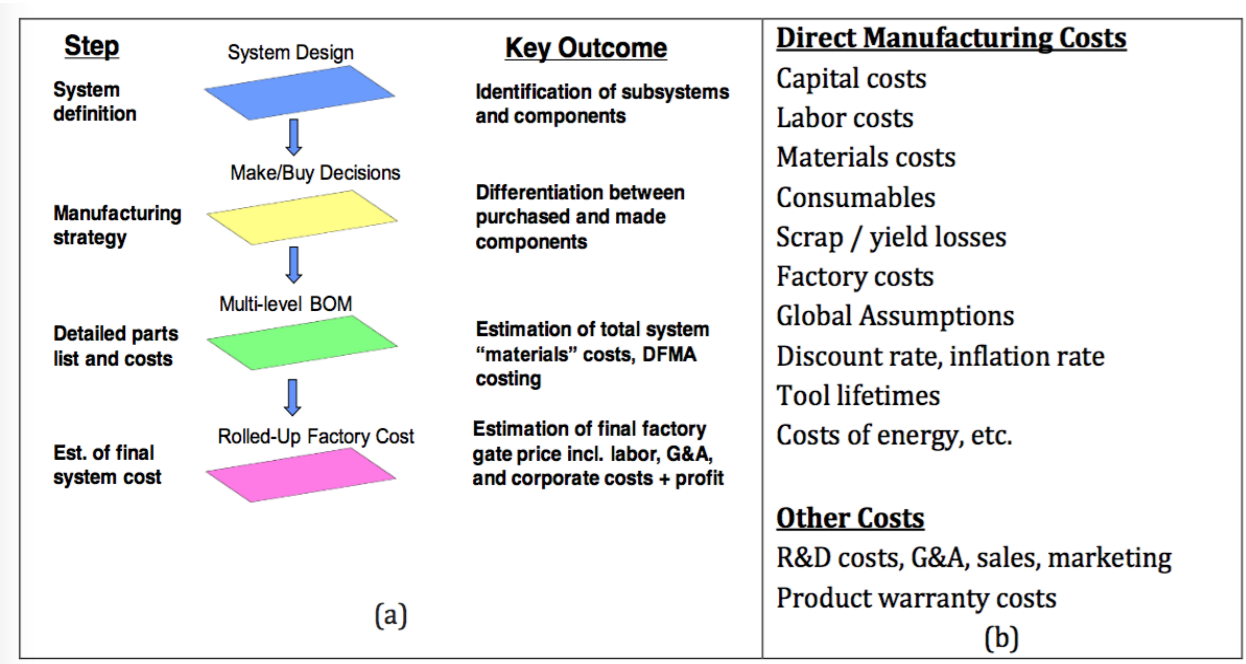


Figure 3-1 Generalized roll-up steps for total system cost

3.1 DFMA costing model approach

This chapter discusses economic analysis used in developing DFMA costing model. This model is adopted from an ASHRAE handbook reference [10].

The definitions of terms used in developing economic equations are reported below.

C_e= cost of energy to operate the system for one period

C_f= floorspace (building) cost

C_{labor} =labor rate per hour

$C_{s,assess}$= initial assessed system value

$C_{s,salvage}$= system salvage value at the end of its useful life in constant dollars

$C_{s\ init}$ = initial system cost

C_y= annualized system cost in constant dollars

$D_{k,sl}$ or **$D_{k,SD}$** = amount of depreciation at the end of period k depending on the type of depreciation schedule used, where D_{ksl} is the straight line depreciation method and D_{kSD} represents the sum-of-digits depreciation method in constant dollars

F= future value of a sum of money

$i_m(P_k)$ = interest charge at the end of period *k*

$i' = (j_d - j)/(1+j)$ = effective interest rate adjusted for inflation rate j and discount rate j_d; sometimes called the real rate

$i'' = (j_d - j_e)/(1+j_e)$ = effective interest rate adjusted for energy inflation j_e

$i''' = (j_{br} - j)/(1+j)$ = effective interest rate adjusted for building depreciation rate j_{br}

I= annual insurance costs

ITC= investment tax credit for energy efficiency improvements, if applicable

j= general inflation rate per period

j_d= discount rate

j_{br} = building depreciation rate

j_e = general energy inflation rate per period

j_m = average mortgage rate (real rate + general inflation rate)

k= end if period(s) in which replacement(s), repair(s), depreciation, or interest is calculated

M= periodic maintenance cost

n= number of period(s) under consideration

P= a sum of money at the present time, *i.e.,* its present value

P_k= outstanding principle of the loan for Cs,init at the end of period *k* in current dollars

R_k= net replacement(s), repair cost(s), or disposals at the end of period *k* in constant dollars

T_{inc}= (state tax rate + federal tax rate) where tax rates are based on the last dollar earned, i. *e.,* the marginal rates

T_{prop} = property tax rate

T_{br} = salvage value of the building

Present value is a common method for analyzing the impact of a future payment on the value of money at the present time. The principle is that all cash flows (those paid now and in the future) should be evaluated according to their present purchasing power. This approach is known as discounting.

The future value F of a present sum of money P over n periods with compound interest rate $\boldsymbol{i}$ can be calculated as following:

$$F = p(1+i)^n$$

The present value or present worth P of a future sum of money F is given by:

$$P = {}^{F}/_{(1+i)^n} = F \times PWF(i,n)$$

where PWF(i,n) the worth factor, is defined by:

$$PWF(i,n) = {}^{1}/_{(1+i)^n}$$

Inflation is the parameter that accounts for the rise in costs of a commodity over time. One way to account for this is to use effective interest rates that account for varying rates of inflation.

The effective interest rate i', sometimes called the real rate, accounts for the general inflation rate j and the discount rate j_d , and can be expressed as follows:

$$i' = \frac{1+j_d}{1+j} - 1 = \frac{j_d - j}{1+j}$$

However, this expression can be adapted to account for energy inflation by considering the general discount rate $j_d$and the energy inflation rate je***,*** thus:

$$i'' = \frac{1+j_d}{1+j_e} - 1 = \frac{j_d - j_e}{1+j_e}$$

When considering the effects of varying inflation rates, the above discount equations can be revised to get the following equation for the future value F, using constant currency of an invested sum P with a discount rate j_d under inflation $\boldsymbol{j}$ during n periods:

$$F = P[\frac{1+j_d}{1+j}]^n = P(1+i')^n$$

The present worth P, in constant dollars, of a future sum of money F with discount rate j_d under inflation rate $\boldsymbol{j}$ during $\boldsymbol{n}$ periods is then expressed as:

$$P = F/[\frac{1+j_d}{1+j}]^n$$

In constant currency, the present worth P of a sum of money F can be expressed with an effective interest rate i', which is adjusted for inflation by:

$$P = {}^{F}/_{(1+i')^n} = F \times PWF(i',n)$$

where the effective present worth factor is given by:

$$PWF(i',n) = {}^{1}/_{(1+i')^n}$$

Another important economic concept is the recovery of capital as a series of uniform payments or what so called, the capital recovery factor (CRF). CRF is commonly used to describe periodic uniform mortgage or loan payments and S is defined as the ratio of the periodic payment to the total sum being repaid. The discounted sum S of such an annual series of payments P_{ann} invested over n periods with interest rate i is given by:

$$S = P_{ann}[1 + (1 + i)^{-n}/i$$

$$P_{ann} = (S \times i)/[1 + (1 + i)^{-n}/i$$

$$CRF(i, n) = \frac{i}{[1 - (1 + i)^{-n}]} = \frac{i(1 + i)^n}{(1 + i)^n - 1}$$

Some of the mathematical formulas used to calculate cost components are tabulated in Table 3-1.

Table 3-1 Mathematical formulas for cost components calculation

$(C_{s,init} - ITC) * CRF(i', n)$	Capital and Interest
$C_{s,salv} * PWF(i', n) * CRF(i', n) * (1 - T_{salv})$	Salvage Value
$\sum_{k=1}^{n}[R_k PWF(i', k)] * CRF(i', n) * (1 - T_{inc})$	Replacement or Disposal
$C_e * \left[\frac{CRF(i', n)}{CRF(i'', n)}\right] * (1 - T_{inc})$	Operating Energy
$\mathrm{C_{br}} = CRF_m * c_{fs} * j_{br}$	Building Cost
$C_{s,assess} T_{prop}(1 - T_{inc})$	Property Tax
$M(1 - T_{inc})$	Maintenance
$I(1 - T_{inc})$	Insurance
$T_{inc} * \sum_{k=1}^{n}[j_m P_{k-1} PWF(i_d, k)]\, CRF(i', n)$	Interest Tax Deduction
$T_{inc} * CRF(i', n) * \sum_{k=1}^{n}[D_k * PWF(i_d, k)]$	Depreciation
$P_k = \left(C_{i,init} - ITC\right) * \left[(1 + j_m)^{k-1} + \frac{(1 + j_m)^{k-1} - 1}{(1 + j_m)^{-n} - 1}\right]$	Principle P_k during year k at market mortgage rate i_m

3.2 Parameters for manufacturing cost analysis

Table 3-2 summarizes the manufacturing cost parameters that are revised from LBNL 2014 values. Important parameters such as the discount rate and average inflation rate are updated.

Table 3-2 Manufacturing cost shared parameters

Parameter	Symbol	LBNL 2014	This work	Units	Reference
Operating hours	t_{hs}	varies	varies	Hours	8 hours base shift
Annual Operating Days	t_{dy}	250	240	Days	52 weeks*5 days/wk. -10 vacation days-10 holidays
Production Availability	A_m	0.85	Varies		
Avg. Inflation Rate	j	0.026	0.0165		US avg. for past 5 years
Avg. Mortgage Rate	j_m	0.05	0.038		mortgage-x.com
Discount Rate	j_d	0.15	0.1		
Energy Inflation Rate	j_e	0.056	0.05		US avg. for last 10 years (www.forecast-chart.com)
Income Tax	i_i	0	0		No net income
Property Tax	i_p	0.014	0.010		US avg. from 2007 (Tax-rates.org, 2015)
Assessed Value	i_{av}	0	0		
Salvage Tax	i_s	0	0		
EOL Salvage Value	k_{eol}	0.02	0.02		Assume 2% of end-of-life value
Tool Lifetime	T_t	15	15	Years	Typical value in practice
Energy Tax Credits	ITC	0	0	Dollars	
Energy Cost	c_e	0.1	0.1	$/kWhe	Typical U.S. value
Floor space Cost	c_{fs}	1291	1291	$\$/m^2$	US average for factory (Selinger, 2011)
Building Depreciation	j_{br}	0.031	0.031		BEA rates (U.S. Department of commerce, 2015)
Building Recovery	T_{br}	31	31	Years	BEA rates (U.S. Department of commerce, 2015)
Building Footprint	a_{br}	Varies	Varies	m^2	
Line Speed	v_l	6	decreased	m/min	
Web Width	W	Varies	Varies	m	Lower widths at low volume
Hourly Labor Cost	c_{labor}	29.81	29.81	$/hr	Hourly wage per worker

An annualized cost of tool approach [10] is adopted. The annualized cost equation can be expressed in constant currency as follows:

$$\mathrm{C_y = C_c + C_r + C_{oc} + C_p + C_{br} + C_i + C_m - C_s - C_{int} - C_{dep}}$$

where

$\mathrm{C_y}$ is the total annualized cost

$\mathrm{C_c}$ is the capital/system cost (with interest)

$\mathrm{C_r}$ is the replacements or disposal cost

$\mathrm{C_{oc}}$ is the operating costs (e.g. electricity) excluding labor

$\mathrm{C_p}$ is the property tax cost

$\mathrm{C_{br}}$ is the building or floor space cost

$\mathrm{C_i}$ is the tool insurance cost

$\mathrm{C_m}$ is the maintenance cost

$\mathrm{C_s}$ is the end-of-life salvage value

$\mathrm{C_{int}}$ is the deduction from income tax

$\mathrm{C_{dep}}$ is the deduction due to tool depreciation

In this cost model $\mathrm{C_r}$, the replacements or disposal cost and $\mathrm{C_i}$, the tool insurance cost, are assumed to be zero. Interest tax credits do not factor into the calculations. From these annualized cost components, the machine rate can be derived including capital cost component, operating cost, and building cost.

Since the parameters have been updated, the interest indexes are changed as in Table 3-3.

Table 3-3 Updated interest rate indices

Parameter	LBNL 2014	This work
Interest rate *i’*	0.121	0.082
Interest rate *i’’*	0.089	0.048
Interest rate *i’’’*	0.005	0.014
CRF,*i’*	0.147	0.118
CRF,*i’’*	0.123	0.095
CRF,*i_m*	0.202	0.056

where

$$\mathrm{CRF}, i_m = j_m * (1 + i''')/(1 - (1 + j_m * (1 + i''')^{-T_{br}})$$

3.3 Building considerations

A process module’s footprint is computed using the following formula:

$$Process\ module\ footprint\ (m^2) = \#\ of\ machines * machine\ size\ (m^2) * 2.8$$

where the 2.8 space correction factor is taken from literature [11]. Building cost is amortized with building depreciation and building life (31 years).

3.4 Yield considerations

As in other costing studies [2] and as will be detailed in the DFMA analysis below, this work assumes that high yield is achieved at high manufacturing volumes. This stems from several implicit assumptions:

- Learning by doing over the cumulative volume of fuel cell component production and greater process optimization will drive yield improvement both within a given vendor, and from vendor to vendor through industry interactions (conferences, IP, cross vendor personnel transfers, etc.)
- Inline inspection improvement with greater inspection sensitivity and more accurate response to defects and inline signals.
- Greater development and utilization of "transfer functions" [12], e.g., development of models that relate inline metrics and measurements to output responses and performance, and resultant improvement in inline response sensitivity and process control.
- Utilization of greater feedback systems in manufacturing processing such as feed-forward sampling, for real time adjustment of process parameters (for example, doctor-blade coating thickness and process parameter control).
- Systematic, integrated analysis to anticipate and prepare for yield excursions e.g., FMEA (failure modes and effect analysis).

3.5 Scrap considerations

"Scrap" material for the CCM module is not discarded but the catalyst is recovered by shipping rejected material to a Pt recovery firm with the assumption that 90% of Pt material is recovered and the remaining 10% Pt is assumed to cover the cost of recovery.

4 DFMA Manufacturing Cost Analysis for CHP applications

4.1 Catalyst coated membrane (CCM)

This project has the objective of estimating the direct manufacturing cost for PEM FC stack components. Here we focus on the CCM, typically the most costly part of the fuel cell stack due to the expensive catalyst material (typically Pt). A total Pt loading of 0.5 mg/cm² is considered [1].

The price of platinum has varied greatly in recent years, with a generally decreasing trend (Fig. 4-1). For this reason it is important to update the cost study with a new catalyst material price, as the cost of platinum is one of the elements that most influence the analysis as can be seen in the sensitivity section.

Figure 4-1 Platinum price trend over the last decade

An average platinum cost over the 2006-2016 time frame of $1402/oz. is assumed in this report, which is lower that the platinum price of $1800/oz. assumed in the 2014 LBNL report

A widely used membrane material used in PEM fuel cells is Nafion®. It was originally developed by DuPont as a chloro-alkali membrane with perfluorinated sulfonic acid (PFSA) the main chemical group. Besides the Pt catalyst, the PEM membrane has been known as one of the most costly components in PEM fuel cells. In this study, Nafion® 211 of 25.1 um thickness, is assumed to be a purchased component.

From different quotes by Dupont a declination curve in price with volume is expected due to economies of scales as in Figure 4-2. All estimates represent membrane material cost alone and do not include any catalyst or catalyst application cost.

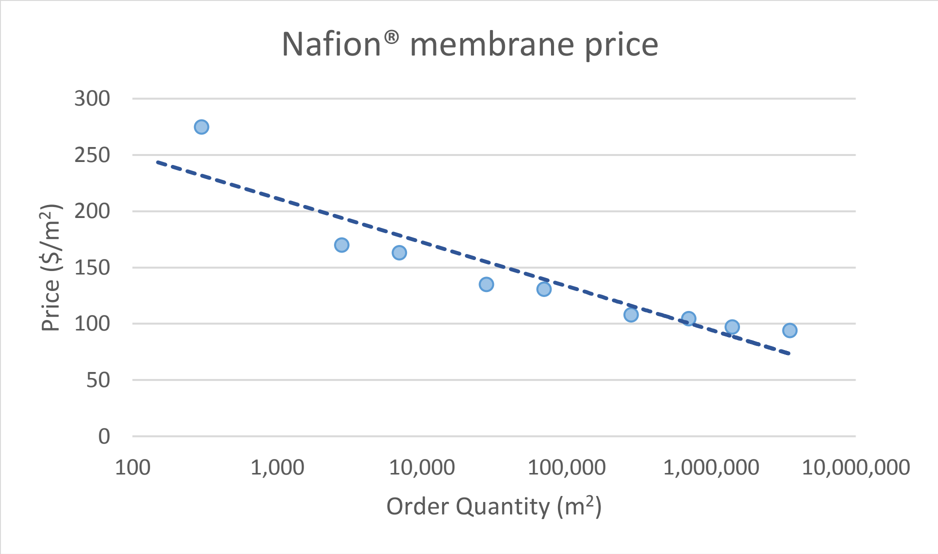


Figure 4-2 Nafion® membrane price

The catalyst layer is made up from a mixture of several materials forming the catalyst ink and deposited over membrane using various coating technologies such as the decal transfer method, dual coating method and/or vapor deposition methods. Table 4-1 shows the ink components and weight fractions taken into consideration in this project.

Table 4-1 Cathode ink constituents based on U.S. Patent 20090169950

BOM- Cathode ink U.S. Patent 20090169950			
Constituent	**Wt. (g)**	**Wt. Fraction**	**Supplier**
Pt	58.29	0.062	Richest Group, Shanghai, China
Carbon black	28.71	0.031	Sigma-Aldrich
Nafion® Ionomer	24.92	0.027	DuPont
Total solids	111.92	0.120	
Solvents	820.75	0.880	Sigma-Aldrich
Total wt.	932.67	1.000	

Based on vendor quotes of Nafion®, and quotes for products similar to Nafion®, it is projected that Nafion® ionomer costs would drop by roughly 95% from low to high production [3]. Figure 4-3 displays the assumed price of Nafion® ionomer used in this cost study.

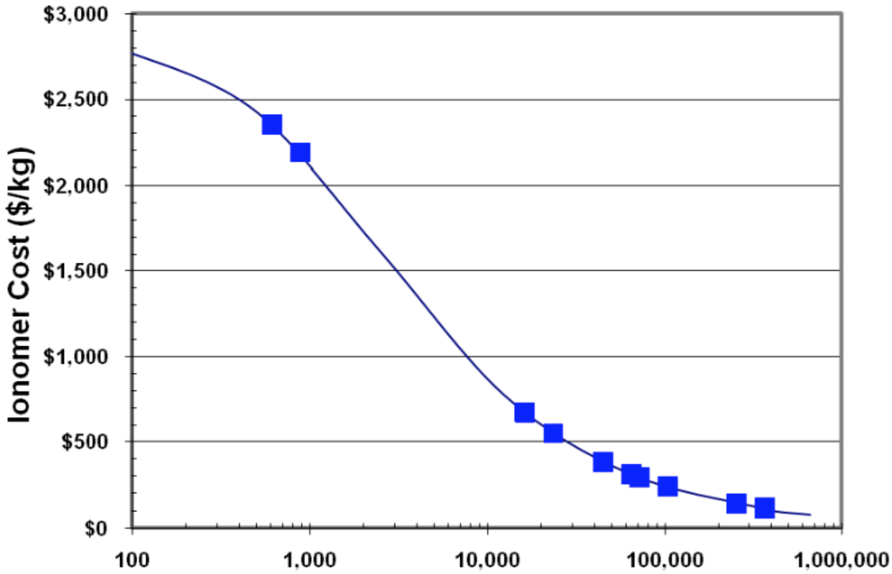
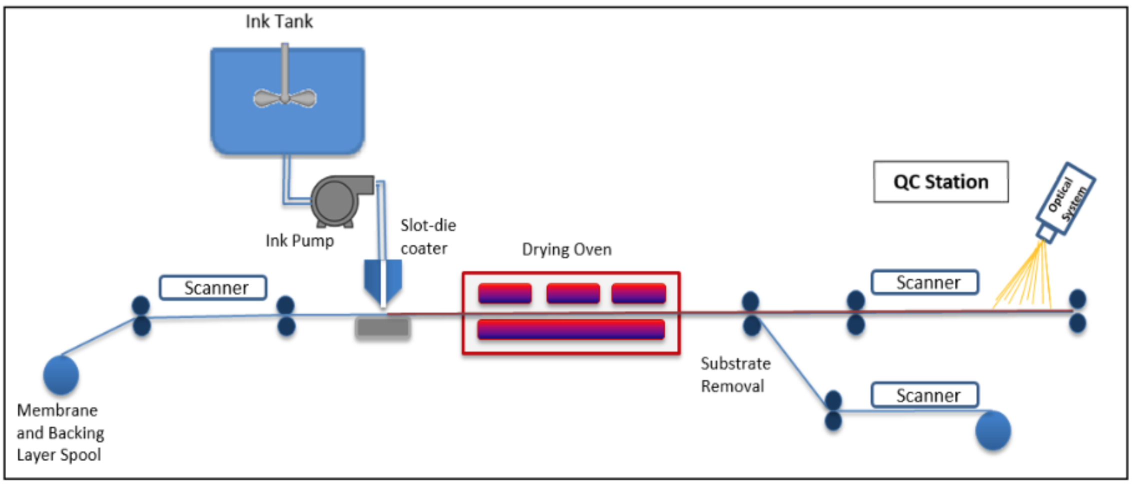


Figure 4-3 Nafion® ionomer price from SA [3]

4.1.1 CCM manufacturing process cost analysis

For this work we adopt a sequential coating for the anode and cathode catalyst, using a roll-to-roll line processing. A future alternative, to decrease process costs, could be a simultaneous double-sided coating; however, problems of membrane swelling and cracking are currently technological hurdles to a fully direct-coated CCM.

Slot die coating is chosen as a representative process for catalyst ink deposition since it is a mature technology with a high degree of process control capability in high volume manufacturing demonstrated for other thin film products and is expected to be able to scale up to larger volumes for the catalyst coating operation. The schematic diagrams below show the general process flow (Fig. 4-4).



(a) Cathode-side

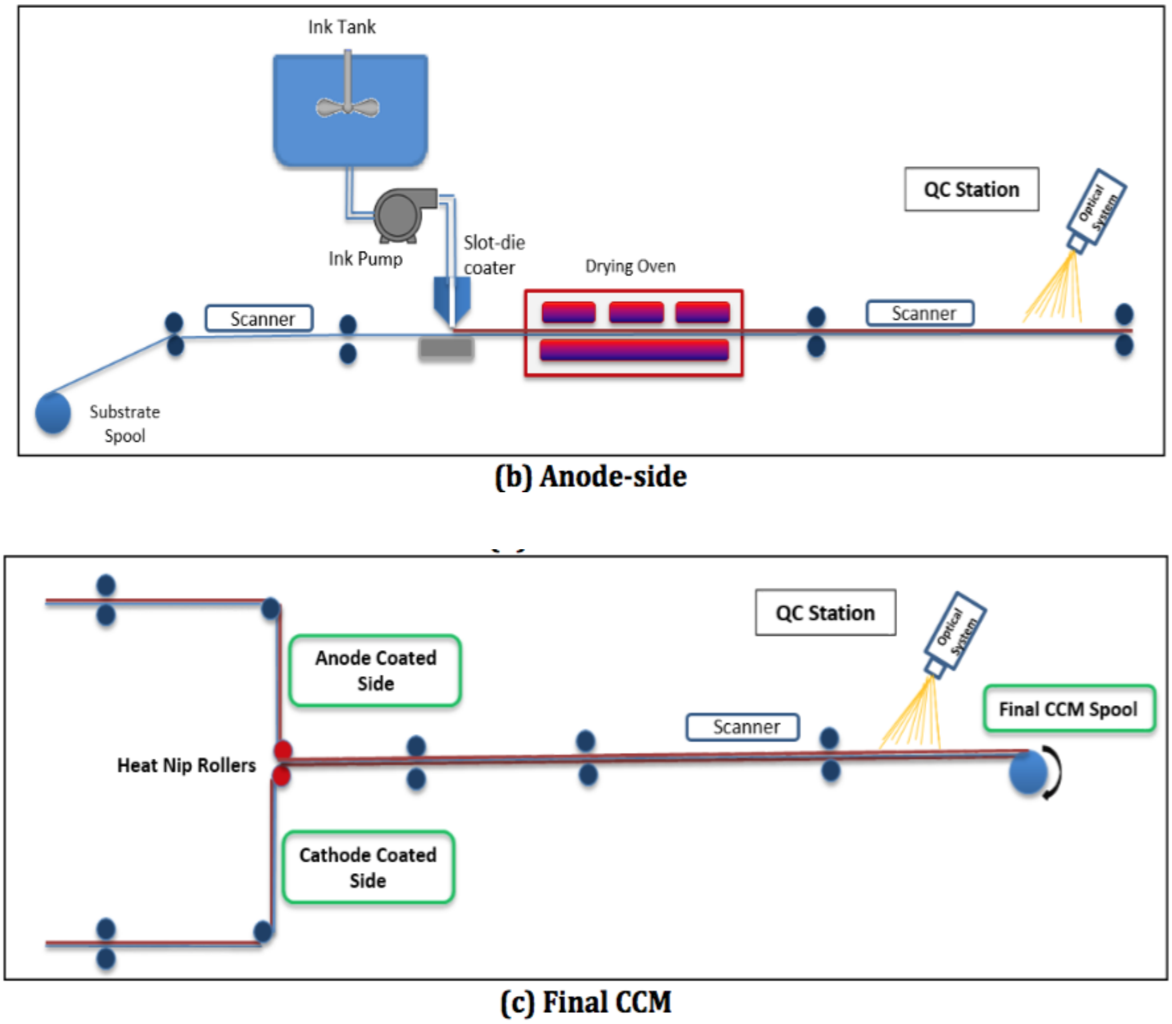


Figure 4-4 CCM manufacturing process as in Wei et al. 2014

For the slot die coating, catalyst-containing ink is mixed in an ink tank and extruded through the slot die coater with an ink pump. Following deposition, the coated membrane passes through an IR drying oven to bake off the ink solvents. For thickness measurement, it is common to have an incoming membrane thickness and post deposition thickness measurement, commonly done with beta gauges. The overall deposition area is enclosed in a clean room environment at Class 1000 to control for contaminants and particles. An inspection is done after each deposition and thermal treatment pass.

4.1.1.1 CCM manufacturing line process parameters

Ideally, the equipment should run at its required rate and make good quality products. In practice, downtime occurs or substandard-quality products are made. These losses, caused by machine malfunctioning and process errors and defects, can be divided into:

• *Down time losses*: when the machine should run, but stands unutilized. Most common down-time losses happen when a malfunction arises, or unplanned maintenance tasks must be done in addition to the major planned upgrades or set-up/start-up activities.

• *Speed losses*: the equipment is running, but it is not running at its maximum designed speed. Most common speed losses happen when equipment speed decreases but is not at zero. These losses can arise from equipment malfunctioning, small technical imperfections, such as stuck packaging or because of the start-up of the equipment related to a maintenance task, setup issues or a stop for organizational reasons.

• *Quality losses*: the equipment is producing products that do not fully meet the specified quality requirements. Most common quality losses occur because equipment, in the time between start-up and completely stable operation, yields products that do not conform to quality demand. They may occur due to incorrect functioning of the machine or because process parameters are not tuned to optimal processing conditions.

These losses can be considered using three different measurable components [19]:

1. *Availability*, the percentage of time that equipment is available to run during the total possible planned production up-time

2. *Line Performance*, the measure of how well the machine runs within target operating times

3. *Process Yield*, the measure of the number of parts that meet specification compared to how many are produced

Process yield and line availability are both functions of annual production volume since level of automation and number of manufacturing lines increase with volume. Under these assumptions, line availability is assumed to be 80% and process yield to be 85% at low volumes (<100,000 units/year). At the highest volumes (>10,000,000 units/year), line availability and process yield are estimated to be 95%. For volumes between 100,000 and 10,000,000 units/year, the process parameters are found through exponential interpolation.

Line performance is assumed to be 89% for manual configuration and 95% for semi-automatic and automatic configurations [14]. The process parameters are shown in Table 4-2.

Table 4-2 CCM manufacturing process parameters assumptions

Power Size (kW)	Systems/year	Process Yield (%)	Availability (%)	Line Performance (%)
1	100	85.0%	80.0%	89.0%
	1,000	88.0%	80.0%	89.0%
	10,000	91.0%	80.8%	95.0%
	50,000	92.0%	85.8%	95.0%
10	100	88.0%	80.0%	89.0%
	1,000	91.0%	80.79%	95.0%
	10,000	92.0%	88.04%	95.0%
	50,000	93.0%	93.49%	95.0%
50	100	90.0%	80.0%	89.0%
	1,000	92.0%	85.79%	95.0%
	10,000	93.0%	93.49%	95.0%
	50,000	94.0%	95.0%	95.0%
100	100	91.0%	80.8%	95.0%
	1,000	92.0%	88.0%	95.0%
	10,000	94.0%	95.0%	95.0%
	50,000	95.0%	95.0%	95.0%
250	100	91.0%	83.6%	95.0%
	1,000	93.0%	91.1%	95.0%
	10,000	94.0%	95.0%	95.0%
	50,000	95.0%	95.0%	95.0%

A sensitivity analysis is also performed (±20% change of availability, performance and process yield) in order to understand how much these factors affect the CCM manufacturing cost.

4.1.1.2 Slot die coating

Slot-die coating is a large-area processing method for the deposition of homogeneous wet films with high cross-directional uniformity. This type of coating technology can handle a broad range of viscosities from less than 1 mPa·s and several thousand Pa·s while the coating speed has a similarly wide spectrum from less than 1 m/min and more than 600 m/min.

The working principle is shown in Figure 4-5. The wet film thickness is controlled by the flow rate, coating width, and speed.

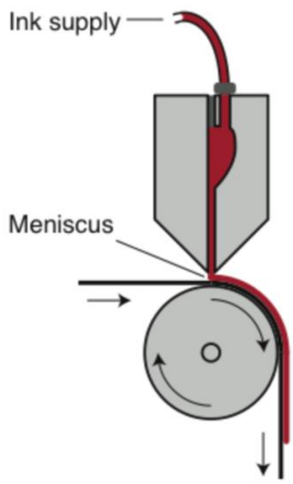


Figure 4-5 Slot die working principle

The slot-die coating head is made from stainless steel and contains an ink distribution chamber, feed slot, and an up and downstream lip. An internal mask (shim) defines the feed slot. The main purpose of slot-die coating is to coat full-width layers but it also allows intermittent batch coating of high viscosity slurries. This permits a patch coated membrane that increases the precious metal utilization compared to a fully coated membrane (Fig. 4-6) [12].

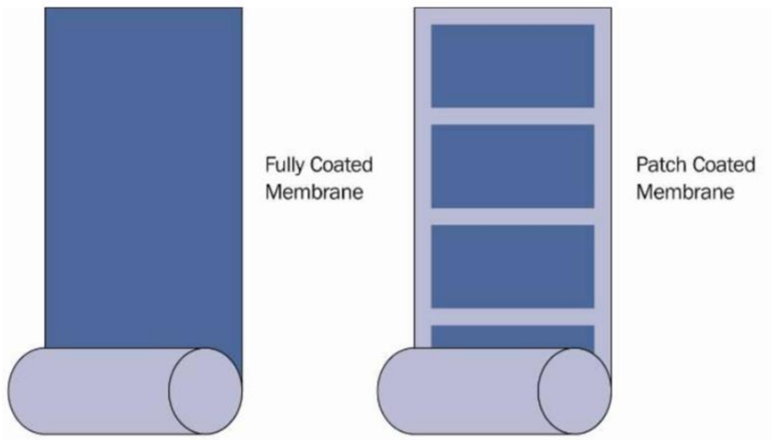


Figure 4-6 Patch coated membrane [12]

4.1.2 CCM manufacturing line process parameters

The slot die coater represents the "bottleneck equipment", limiting all the other machines of the production line. This means that all machines in the production line will operate for a number of hours per year equal to the annual operating hours of slot die coater.

The principal factors taken into account in the slot die coating process analysis, in order to estimate the annual production capacity and the required size of slot die coating machine, are:

- web width
- line speed

4.1.2.1 Web width assumptions

For the choice of web width, a margin of 1 cm on each side of the web is assumed. Since the slot die coater can be manufactured at any desired width, this dimension is calculated based on the number of pieces made simultaneously.

We assume, as in the LBNL cost study, that 4 cells are coated simultaneously for an annual production volume < 2,500 MW and 9 cells for annual production volume > 2,500 MW (Table 4-3).

Table 4-3 Web width assumptions

Web Width (m)		
Annual production volume (MW/year)	> 2.5	< 2.5
LBNL 2014	0.45	0.90
This work	0.42	0.92

4.1.2.2 Line speed assumptions

The choice of an appropriate line speed is extremely difficult since it depends upon the length of drying chamber and the required thickness of the ink used [15]. For these reasons and for better process control, the previous assumption of 6 m/min for all production volumes is probably overaggressive. Based on vendor discussions, a line speed of 2 m/min for high production (> 1 MW) and a line speed of 1 m/min for low production (< 1 MW) are assumed for this work (Table 4-4).

Table 4-4 Line speed assumptions

Line speed (m/min)		
Annual production volume (MW/year)	> 1	< 1
LBNL 2014	6	6
This work	2	1

A line speed sensitivity analysis (±20%) is conducted to understand how much the production rate (m/min) affected the CCM cells manufacturing cost (Section 4.1.5).

Other important parameters, derived from LBNL cost study [14], are considered:

- *Required roll length*

$$Required\ roll\ length\ \left(\frac{m}{year * line}\right) = \frac{cell\ size\ (m) * \frac{\frac{cells\ required}{year}}{Process\ Yield}}{\frac{\#\ of\ cells\ done\ simultaneously}{line}}$$

- *Setup times*

Different setup times are included in this analysis compared to the previous LBNL work that assumed

1 hour setup per working day. Setup times considered in this analysis are related to the required roll length and results in higher values of the setup hours per year.

- *Max roll length*

Assuming a value of one hour as setup time, 16 operational hours per day and 240 operational days (48 operating weeks) per year the maximum length achievable with one machine is:

$$\frac{Max\ carrier\ length(m)}{line * day} = speed\ \left(\frac{m}{h}\right) * Line\ Performance * \left[\frac{op. hours}{day * line} - \frac{\frac{req\ carr\ length}{day}}{1000}\right]$$

$$\frac{Max\ carrier\ length(m)}{line * year} = speed\ \left(\frac{m}{h}\right) * Line\ Performance * \left[\frac{op. hours}{year * line} - \frac{setups}{year}\right] * Availability$$

- *Number of lines*

$$\#\ of\ lines = \frac{Required\ roll\ length(m/year)}{Max\ roll\ length\ (\frac{m}{line * year})}$$

- *Line utilization*

$$Line\ utilization\ (\%) = \frac{Required\ carrier\ length(m/year)}{Max\ carrier\ length\ \left(\frac{m}{line * year}\right) * \ \#\ of\ lines}$$

- *Number of cells per day*

$$\frac{\#\ of\ cells}{day * line} = \frac{\frac{Max\ carrier\ length}{line * day}\left(\frac{m}{day * line}\right) * \#\ of\ cells\ done\ simultaneously}{cell\ size\ (m)}$$

$$\frac{\#\ of\ cells}{day} = \frac{\#\ of\ cells}{day * line} * \#\ of\ lines$$

- *Number of cells per week*

$$\frac{\#\ of\ cells}{week * line} = \frac{\#\ of\ cells}{day * line} * 5\ \frac{operational\ days}{week}$$

$$\frac{\#\ of\ cells}{week} = \frac{\#\ of\ cells}{week * line} * \#\ of\ lines$$

- *Annual operating hours*

$$Annual\ operating\ hours = \frac{Required\ roll\ length\left(\frac{m}{year}\right)}{line\ speed\ \left(\frac{m}{h}\right) * Line\ Performance} + \ Number\ of\ setups\ (\frac{hours}{year})$$

$$\frac{Annual\ operating\ hours}{line} = \frac{Annual\ operating\ hours}{\#\ of\ lines}$$

- *Labor cost*

For annual production > 1 MW the presence of two workers per line is considered; for low annual production, where the process is not completely mature and more inspections are needed, a total labor cost equal to the 25% of an engineer's annual salary is assumed.

- *Capital cost*

Slot-die equipment quotes are derived from Conquip, Inc., consistent with quotes from other vendors such as Eurotech/Coatema Coating Machinery GmbH (Table 4-5).

Table 4-5 Slot die capital costs

Slot die coater		
Annual production volume (MW/year)	< 2,500	> 2,500
Capital Cost ($)	513,980	1,521,000

Additional CCM process line considerations are as follows:

- Maintenance factor of 0.10 [1]
- Machine footprint based on web width and line length and assumed class 1000 clean room for slot die-coater and IR oven
- Initial system costs assume installation costs are 10% of equipment capital cost (based on EuroTech and Conquip estimates)
- Salvage value is the amortized end-of-life value of the tool
- Property tax is proportional to the machine capital

Table 4-6 shows the machine rates for the slot-die coater for the 100 kW base system where the machine cost can be divided in 3 principal components:

$Capital\ cost = annual\ capital\ payment - salvage\ value$

$Operational\ cost = maintenance + energy\ cost$

$Building\ cost = property\ tax + cleanroom\ cost$

Table 4-6 Slot die coating cost summary

Slot Die Coater				
System size (KW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Max Web Width (m)	0.42	0.42	0.42	0.92
Line Speed (m/min)	2	2	2	2
Number of Lines	1	1	4	7
cells required/year	158600	1586000	15860000	79300000
Line Utilization (%)	3.63%	33.25%	76.07%	95.58%
cell length with 10 mm margin (m)	0.27	0.27	0.27	0.27
cell width with 10 mm margin (m)	0.10	0.10	0.10	0.10
no of cells done simultaneously	4	4	4	9
required roll length(m)	11655.4	115286.7	1128337.8	2481023.4
max roll length/line/day	1824.0	1824.0	1824.0	1824.0
max roll length including setup/line/day	1616.1	1616.1	1616.1	1616.1
max roll length/line/year (m)	353653.6	385385.1	415872.0	415872.0
max roll length including setup/line/year(m)	321083.0	346707.5	370833.1	370833.1
Max No of cells/year/line	4801241	5184411	5545167	12476626
cells/day/line	24165	24165	24165	54372
cells/week/line	120825	120825	120825	271860
No of operational weeks required	2	14	33	42
# of setups / year	12	116	1129	2482
Annual Operating Hours (No setup)	102.2	1011.3	9897.7	21763.4
Annual Operating Hours/line (No setup)	102.2	1011.3	2474.4	3109.1
Annual Operating Hours (+setup time)	114.2	1127.3	11026.7	24245.4
Annual Operating Hours/line (+setup time)	114.2	1127.3	2756.7	3463.6
Labor cost($)	6811.0	67208.8	657411.8	1445508.5
Maintenance factor	0.10	0.10	0.10	0.10
Machine Footprint (m2)	14.28	14.28	57.12	352.8
Initial Capital ($)	513980	513980	2055920	10647000
Initial System Cost ($)	565378	565378	2261512	11711700
Annual Depreciation ($/yr)	33580	33580	134320	695604
Annual Cap Payment ($/yr)	66917	66917	267668.1	1386173.5
Maintenance ($/yr)	6083.4	6083.4	24333.5	126015.8
Salvage Value ($/yr)	186.2	186.2	744.7	3856.5
Energy Costs ($/yr)	142.6	1407.4	13767.1	30271
Property Tax ($/yr)	2127.9	2127.9	8511.5	44078.6
Cleanroom Costs ($/yr)	3207.3	3207.3	12829.1	79238.7
Machine Cost ($/yr)	78292.0	79556.8	326364.6	1661921.0
Capital	66730.8	66730.8	266923.4	1382316.9
Operational	6226	7490.8	38100.6	156286.8
Building	5335.2	5335.2	21340.6	123317.2
Machine Rate ($/h)	685.3	70.6	29.6	68.5
Capital	584.1	59.2	24.2	57
Operational	54.5	6.6	3.5	6.4
Building	46.7	4.7	1.9	5.1

4.1.2.3 Infrared oven

After slot die coating, the membrane passes through an IR drying oven to bake off the ink solvents. Infrared drying is a complicated process where the drying temperature must be kept below the solvent boiling temperature to avoid formation of air bubbles [16]. From a cost study from Battelle, we assume it takes 2.5 minutes to dry 40 um of catalyst and 5 minutes for 80 um.

Principal constituents of cathode/catalyst ink are shown in Table 4-7.

Table 4-7 Principal catalyst ink constituents

Cathode/Catalyst components	Weight %	g/cm^3
Pt	6.2	21.45
Carbon black	3.1	2.09
Nafion Ionomer	2.7	2.2
Solvents	88	1

The following calculations are performed:

- 100 grams of wet catalyst contains 6,2 grams of Pt and has a volume of $\frac{6,2}{21,45} + \frac{3,1}{2,09} + \frac{2,7}{2,2} + \frac{88}{1} = 91\ cm^3$
- Wet catalyst density is $\frac{100}{91} = 1,10\frac{g}{cm^3}$
- Pt content of the wet catalyst is $\frac{6,2}{91} = 0,068\frac{g}{cm^3}$
- To obtain a loading of $0,4\frac{mg}{cm^2}$ (cathode) and $0,1\frac{mg}{cm^2}$ (anode), the depth of wet catalyst layers are:
- cathode: $\frac{0,4}{68} = 0,0059cm = 59\ um$
- anode: $\frac{0,1}{68} = 0,0015cm = 15\ um$

Table 4-8 Wet catalyst thickness

	Case 1	This work	Case 2
Wet catalyst depth (um)	40	59	80
Drying time (min)	2.5	3.6875	5

To be conservative, a drying time of 4 minutes is assumed.

Required oven tunnel length

$$minimum\ required\ tunnel\ length = line\ speed * drying\ time$$

Table 4-9 illustrates infrared oven capital costs.

Table 4-9 Infrared oven capital costs

Infrared oven		
Web width (m)	0.42	0.92

Capital Cost ($)	107,000	360,000

Table 4-10 summarizes the machine rates for the infrared oven for a 100 kW system.

Table 4-10 Infrared oven cost summary

Infrared oven				
System size (KW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
line speed(m/min)	2	2	2	2
drying time (min)	4	4	4	4
min required tunnel length(m)	8	8	8	8
Power Consumption/oven (kW)	50	50	50	50
Machine Footprint (m2)	7.14	7.14	28.56	176.4
Initial Capital ($)	107000	107000	428000	2520000
Initial System Cost ($)	117700	117700	470800	2772000
Annual Depreciation ($/yr)	6991	6991	27963	164640
Annual Cap Payment ($/yr)	13931	13931	55723	328088
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance ($/yr)	1266	1266	5066	29826
Salvage Value ($/yr)	39	39	155	913
Energy Costs ($/yr)	1426	14074	137671	302710
Property Tax ($/yr)	443	443	1772	10433
Building Costs ($/yr)	1604	1604	6415	39619
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation ($/yr)	0	0	0	0
Machine Cost ($/yr)	18631.3	31279.5	206491.6	709764.2
Capital	13892.0	13892.0	55567.9	327175.6
Variable	2692.7	15340.9	142737.2	332536.4
Building	2046.6	2046.6	8186.5	50052.1
Machine Rate ($/h)	163.1	27.7	18.7	29.3
Capital	121.6	12.3	5.0	13.5
Variable	23.6	13.6	12.9	13.7
Building	17.9	1.8	0.7	2.1

4.1.2.4 Mixing and pumping system

The LBNL 2014 cost study analyzed just one mixing and pumping model, inferred from a decal transfer coating process for a 100 kW system. Because the assumptions of lower line speed, this mixing and pumping system is essentially oversized for low annual production volume.

In this project, two different types of mixing and pumping systems according to fuel cell size are assumed.

The value of slurry volume/hour/line is the parameter to size the fuel cell system.

$$\frac{slurry\ volume}{hour * line}\left(\frac{L}{hour}\right) = \frac{\frac{cells\ casted}{day * line} * \frac{slurry\ volume}{cell}\left(\frac{L}{cell}\right)}{\frac{operational\ hours}{day}\left(\frac{hours}{day}\right)}$$

Slurry volume/cell is calculated starting from electrodes bill of materials and considering the volume/cell of all these components (Table 4-11).

Table 4-11 Slurry volume/cell for the cathode

CATHODE bill of materials	g/ 100 cm^2	g/cell active area (231.75 cm^2)	Density (g/cm^3)	Slurry volume/ cell (cm^3)
Pt	4	9.24	21.45	0.43
carbon black	1.97	4.55	2.09	2.17
Nafion Ionomer	1.71	3.95	2.2	1.79
solvents	56.32	130.10	1	130.10
TOTAL				134.51

If slurry volume/hour/line is less than 300 L/h, we assume an ultrasonic mixer from Industrial Sonomechanics LLC. If slurry volume/hour/line is more than 300 L/h, the LBNL 2014 mixing and pumping system is considered. Ultrasonic mixers can achieve higher production rates and better final product quality since ultrasonic cavitation also help to disperse particles effectively.

Table 4-12 summarizes capital costs and power consumptions of these two systems.

Table 4-12 Mixing and pumping capital costs

Mixing and pumping system		
Slurry volume/hour/line (L/h)	< 300	> 300
Capital Cost ($)	37,000	204,000

Table 4-13 illustrates mixing and pumping machine rates for 100 kW fuel cell systems. For the total cost calculation, this cost component will be taken into account twice, once for the cathode and once for the anode. For labor cost, one worker per line is assumed.

Table 4-13 Mixing and pumping costing summary

Mixing and pumping				
System size (KW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Type of Mixer	A	A	A	B
slurry volume/cell (cm3)	134.51	134.51	134.51	134.51
slurry volume/hour/line (L/hour)	251.46	230.76	213.84	481.15
workers	1	1	4	7
Total No of Mixers	1	1	4	7
Labor hours	114.24	1127.29	2756.67	3463.62

Labor cost ($)	3405.49	33604.42	328705.92	722754.27
Maintenance factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption(KW)	5	5	20	35
Machine Footprint (m2)	3.57	3.57	14.28	88.2
Initial Capital ($)	74000	74000	296000	1430000
Initial System Cost ($)	81400	81400	326000	1570000
Annual Depreciation ($/yr)	4830	4830	19300	93300
Annual Cap Payment ($/yr)	9630	9630	38500	186000
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance ($/yr)	875.9	875.9	3503.4	16901.5
Salvage Value ($/yr)	26.8	26.8	107.2	517.2
Energy Costs ($/yr)	142.6	1407.5	13767.2	30271.0
Property Tax ($/yr)	306.4	306.4	1225.4	5911.9
Building Costs ($/yr)	801.8	801.8	3207.3	19809.7
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation ($/yr)	0	0	0	0
Machine Cost ($/yr)	11734.2	12999.0	60133.4	258293.6
Capital	9607.5	9607.5	38430.2	185399.5
Variable	1018.5	2283.3	17270.5	47172.5
Building	1108.2	1108.2	4432.7	25721.6
Machine Rate ($/h)	102.7	11.5	5.5	10.7
Capital	84.1	8.5	3.5	7.6
Variable	8.9	2.0	1.6	1.9
Building	9.7	1.0	0.4	1.1

4.1.2.5 Quality control unit

For inspection and testing procedures involved in this analysis, assumptions from the LBNL 2014 cost study are followed.

Quality control system is divided in:

- Infrared imaging (to detect defects on the surface or close to the surface)
- Ultrasonic spectroscopy (to detect defects on the surface or under the surface)

Two configurations are analyzed:

Table 4-14 Quality control unit configurations

Quality control unit		
annual production volume (MW/year)	< 25	> 25
configuration	Manual	Automatic
Cycle time (s)	15	4
Workers/line	2	1

Table 4-15 summarizes capital costs of infrared inspection and ultrasound inspection for manual and automatic configuration.

Table 4-15 Quality control unit capital costs

Quality control unit		
configuration	Manual	Automatic
Infrared inspection cost ($)	50,000	150,000
Ultrasound inspection cost ($)	20,000	150,000

The maximum number of cells tested per week is estimated as:

$$\frac{Max\ number\ of\ cells\ tested}{week \cdot machine} = \frac{\frac{hours}{week \cdot machine} \cdot 3600 \cdot process\ yield\ (\%)}{cycle\ time\ (s)}$$

If cells made simultaneously are less than four, one quality control system per line is assumed, if cells casted simultaneously are more than four, two machines per line are assumed.

Table 4-16 Number of quality systems per line

uality control unit		
Cells made simultaneously	< 4	> 4
Quality systems per line	1	2

Table 4-17 shows machine rates and corresponding costs for quality control systems in the case of 100 kW systems.

Table 4-17 Quality control system cost summary

Quality control system				
System size (KW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
type of handling and inspection	manual	automatic	automatic	automatic
No of machines	1	1	4	14
Bottle neck time(s)	15	4	4	4
Max cells tested/week/machine	17472	66240	67680	68400
Annual operating hours	114.24	1127.29	11026.7	24245.36
No of workers/station	2	1	1	1
Labor Cost	20432.9	100813.2	986117.7	4336525.6
Maintenance factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption/machine(kW)	10	10	10	10
Machine Footprint (m2)	2.38	2.38	9.52	58.8
Initial Capital ($)	210000	900000	3600000	12600000
Initial System Cost ($)	231000	990000	3960000	13860000
Annual Depreciation ($/yr)	13720	58800	235200	823200

Annual Cap Payment ($/yr)	27340.7	117174.4	468697.7	1640442.0
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance ($/yr)	2485.5	10652.2	42608.9	149131.1
Salvage Value ($/yr)	76.1	326.0	1304.0	4563.9
Energy Costs ($/yr)	427.9	4222.3	41301.4	181626.1
Property Tax ($/yr)	869.4	3726.0	14904.0	52164.0
Building Costs ($/yr)	534.5	534.5	2138.2	13206.4
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation ($/yr)	0	0	0	0
Machine Cost ($/yr)	31582.0	135983.5	568346.2	2032005.7
Capital	27264.6	116848.4	467393.7	1635878.0
Variable	2913.4	14874.6	83910.3	330757.2
Building	1403.9	4260.5	17042.2	65370.4
Machine Rate ($/h)	276.5	120.6	51.5	83.8
Capital	238.7	103.7	42.4	67.5
Variable	25.5	13.2	7.6	13.6
Building	12.3	3.8	1.5	2.7

4.1.2.6 Wind and unwind tensioners

We refer to the LBNL 2014 report for wind and unwind tensioner capital costs.

Table 4-18 Wind and unwind tensioners cost summary

Wind and Unwind tensioners		
Web width (m)	0.42	0.92
Capital Cost ($)	204,000	645,000

Table 4-19 illustrates wind and unwind machine rates for 100 kW fuel cell systems. For the total cost calculation, this cost component will be taken into account twice, once for the cathode and once for the anode.

Table 4-19 Wind and unwind tensioners cost summary

Wind and unwind tensioners				
System size (KW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Maintenance factor	0,1	0,1	0,1	0,1
Auxiliary Costs Factor	0	0	0	0
Power Consumption	10	10	10	10
Machine Footprint (m2)	8,33	8,33	33,32	205,8
Initial Capital	207000	207000	828000	4515000
Initial System Cost	227700	227700	910800	4966500
Annual Depreciation ($/yr)	13524	13524	54096	294980
Annual Cap Payment ($/yr)	26950,1	26950,1	107800,5	587825,0

Auxiliary Costs ($/yr)	0	0	0	0
Maintenance ($/yr)	2450,0	2450,0	9800,0	53438,6
Salvage Value ($/yr)	75,0	75,0	299,9	1635,4
Energy Costs ($/yr)	285,3	2814,9	27534,3	60542,0
Property Tax ($/yr)	857,0	857,0	3427,9	18692,1
Building Costs ($/yr)	1870,9	1870,9	7483,7	46222,5
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation ($/yr)	0	0	0	0
Machine Cost ($/yr)	32338,3	34867,9	155746,5	765085,0
Capital	26875,1	26875,1	107500,6	586189,6
Variable	2735,3	5264,9	37334,3	113980,7
Building	2727,9	2727,9	10911,6	64914,6
Machine Rate ($/h)	283,1	30,9	14,1	31,6
Capital	235,3	23,8	9,7	24,2
Variable	23,9	4,7	3,4	4,7
Building	23,9	2,4	1,0	2,7

4.1.3 CCM cost summary

Table 4-20 summarizes the CCM manufacturing cost ($/kW) over the equivalent production (MW/year).

Table 4-20 CCM manufacturing cost results ($/kW)

Annual Production Volume (MW/year)	**CCM cost ($/kW)**
0.1	2,505.5
1	443.9
5	234.7
10	207.4
25	184.7
50	175.6
100	162.3
250	151.4
500	150.1
1,000	139.7
2,500	131.9
5,000	126
12,500	119.3

The CCM manufacturing cost decreases at higher production volumes, from about $2,500/kW (100 kW/year), to $120/kW (12,500 MW/year).

Table 4-21 and Table 4-22 show CCM manufacturing costs breakdown for 1 kW and 100 kW system sizes, respectively. Manufacturing costs are split into several components to highlight the effect of each cost component on the overall cost of CCM. These cost components include: capital cost, operational cost, building cost, labor cost, material cost, and material scrap cost.

Material scrap represents a cost and the quantity of material rejected and varies inversely with the yield. Platinum can be recovered with 90% of the Pt value recovered. No recovery is assumed for the Nafion® membrane since the recovery process may damage the membrane structure. Thus, a negative material cost means that net positive value is recorded from material scrap that is sold for precious metal recovery.

Table 4-21 CCM cost breakdown for 1 kW system

System size (kW)	1			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	264.8	222.4	191.0	174.6
Direct Labor ($/kW)	237.5	23.8	3.3	2.2
Process: Capital ($/kW)	1443.7	144.4	14.4	4.7
Process: Operational ($/kW)	132.4	13.7	1.6	0.7
Process: Building ($/kW)	126.2	12.6	1.3	0.3
Material Scrap ($/kW)	300.9	27.0	2.3	-0.1
Final Cost ($/kW)	2505.5	443.8	213.9	182.3

Table 4-22 CCM cost breakdown for 100 kW systemSystem size (kW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	178.8	158.0	138.0	125.5
Direct Labor ($/kW)	3.1	2.0	2.0	1.3
Process: Capital ($/kW)	14.4	2.3	0.9	0.8
Process: Operational ($/kW)	1.6	0.5	0.3	0.2
Process: Building ($/kW)	1.3	0.2	0.1	0.1
Material Scrap ($/kW)	2.3	-0.7	-1.6	-1.9
Final Cost ($/kW)	201.5	162.3	139.7	126.0

These tables show that at low volumes capital cost constitutes the biggest contribution to CCM cost, while at higher volume, material costs dominate. The following figures illustrate the CCM cost components as a percentage of total cost for the 1 kW and 100 kW cases.

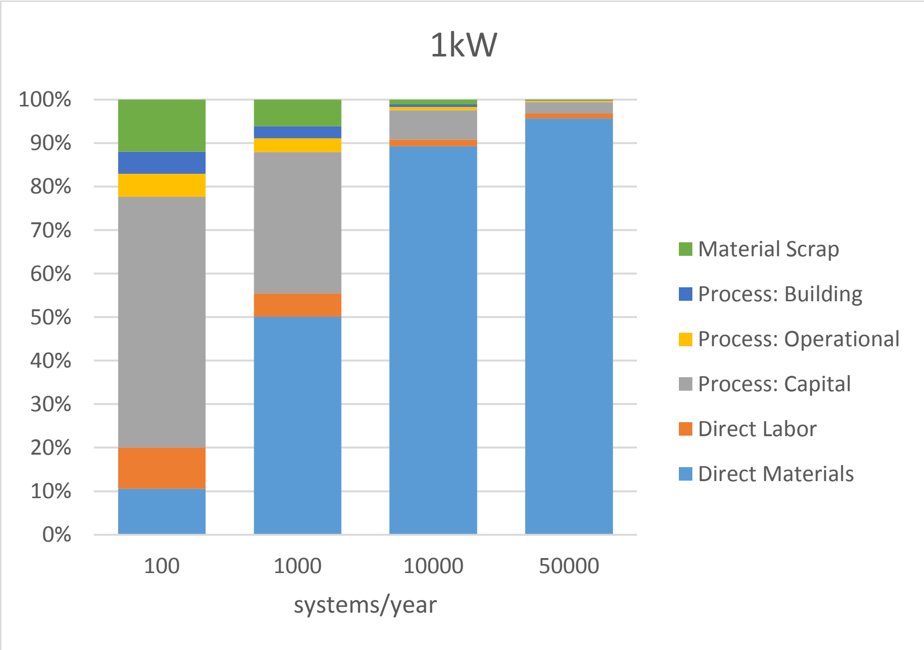


Figure 4-7 CCM percentage cost breakdown for 1 kW system

Compared to previous LBNL work the direct labor is an important cost component at low production, at 100 and 1000 systems/year, respectively, making up 10% and 5% of the overall CCM cost. This is due to higher labor cost assumption for low production volume.

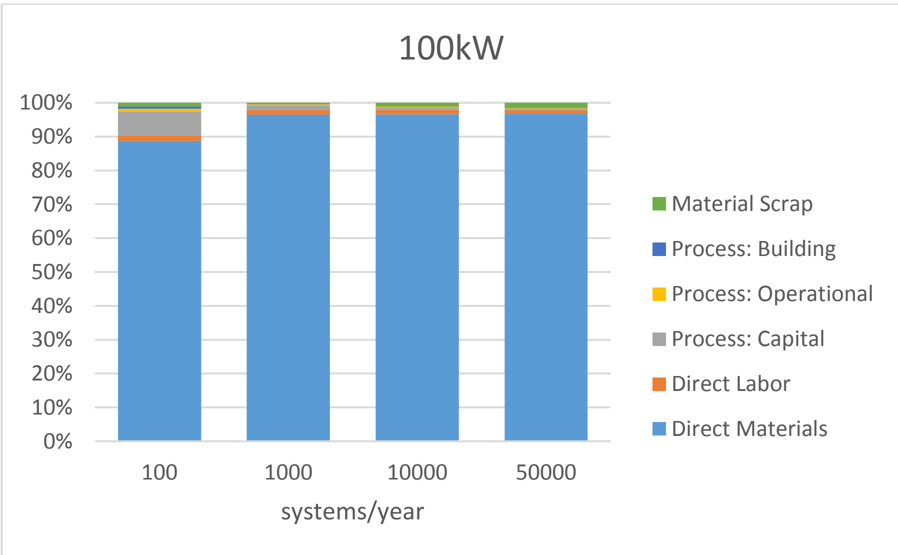


Figure 4-8 CCM percentage cost breakdown for 100 kW system

As can be noted, at 1 kW, 100 systems/year, capital costs constitute over 50% of CCM cost, while for 1,000 systems/year, capital costs make up about 30% of overall cost. At higher annual production volume above 10 MW, material cost is the principal cost component, covering 90-95% of total CCM cost.

Platinum is the dominant material cost followed by Nafion® membrane. Platinum accounts for 48% of total CCM material cost of the 1 kW fuel cell at an annual production volume of 1,000 units, and this fraction jumps to around 73% of total CCM material cost for 100 kW fuel cell system at an annual production volume of 50,000 units.

4.1.4 CCM manufacturing costs compared to LBNL cost results

Table 4-23 shows the CCM manufacturing cost comparison in terms of $/m² over annual production volume.

Table 4-23 CCM manufacturing cost comparison

Annual production volume (MW/year)	**LBNL 2014 CCM costs $/m²**	**This work CCM costs $/m²**
1	1,298.8	1,126.6
5	679.5	620.7
10	584.4	542.9
25	519.4	503.2
50	488.2	464.4
100	466.2	440.5
250	440.6	412.5
500	425.1	397.0
1,000	411.8	380.0
2,500	392.0	359.4
5,000	379.3	342.7
12,500	362.4	324.9

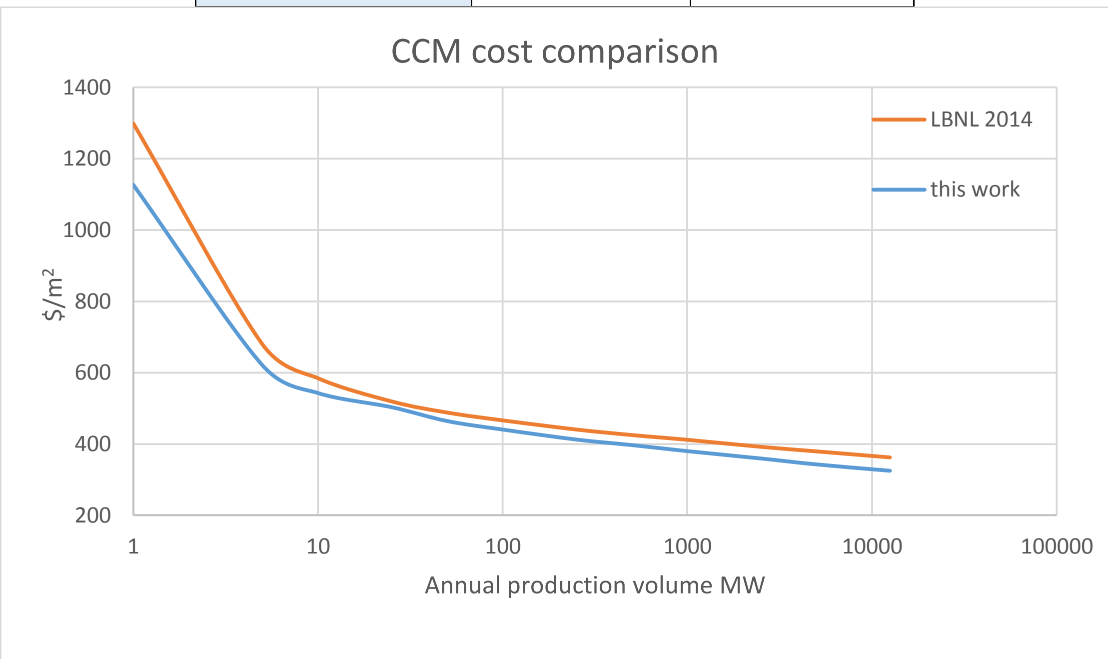


Figure 4-9 CCM manufacturing cost comparison

In general, at low production volume costs are high due to expensive investment and low equipment utilization. New results are lower than previous LBNL analysis for various reasons:

- At low production, where capital cost mostly affects the overall cost, a lower discount rate is assumed.
- At high production, where material cost is the principal cost component, we consider a lower price of platinum.

4.1.5 CCM cost sensitivity

The following figures show the results of the CCM sensitivity analysis, conducted for 100 kW systems at different annual production volumes. The impact to the CCM cost in $/kW is calculated for a ±20% change in the sensitivity parameter being varied.

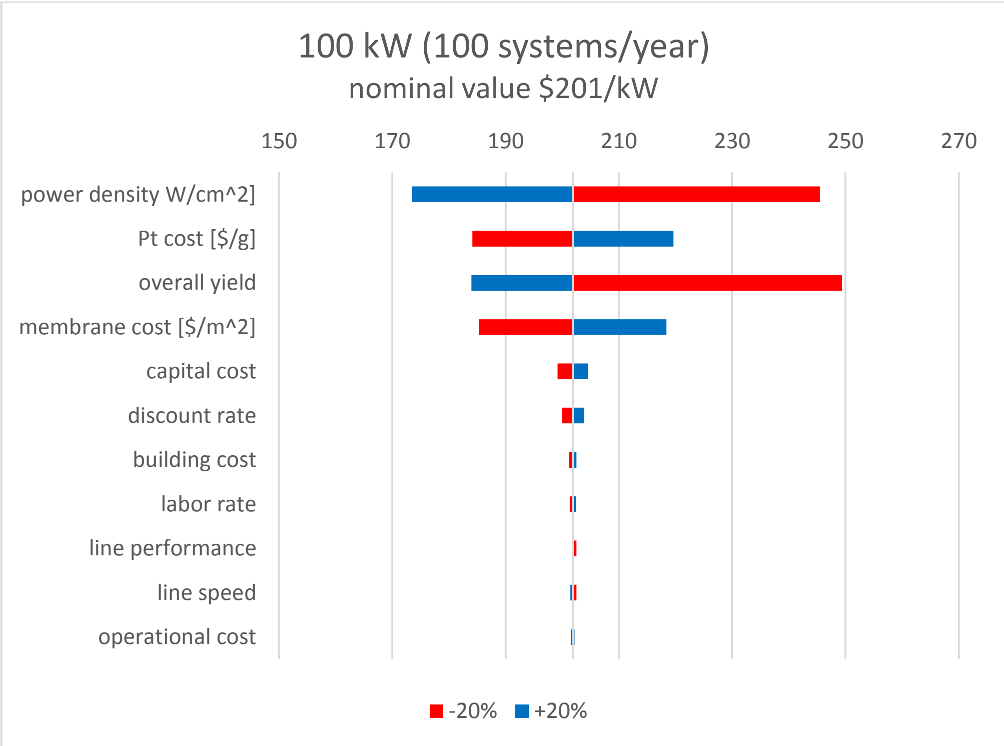


Figure 4-10 CCM sensitivity for 100 kW and 100 systems/year

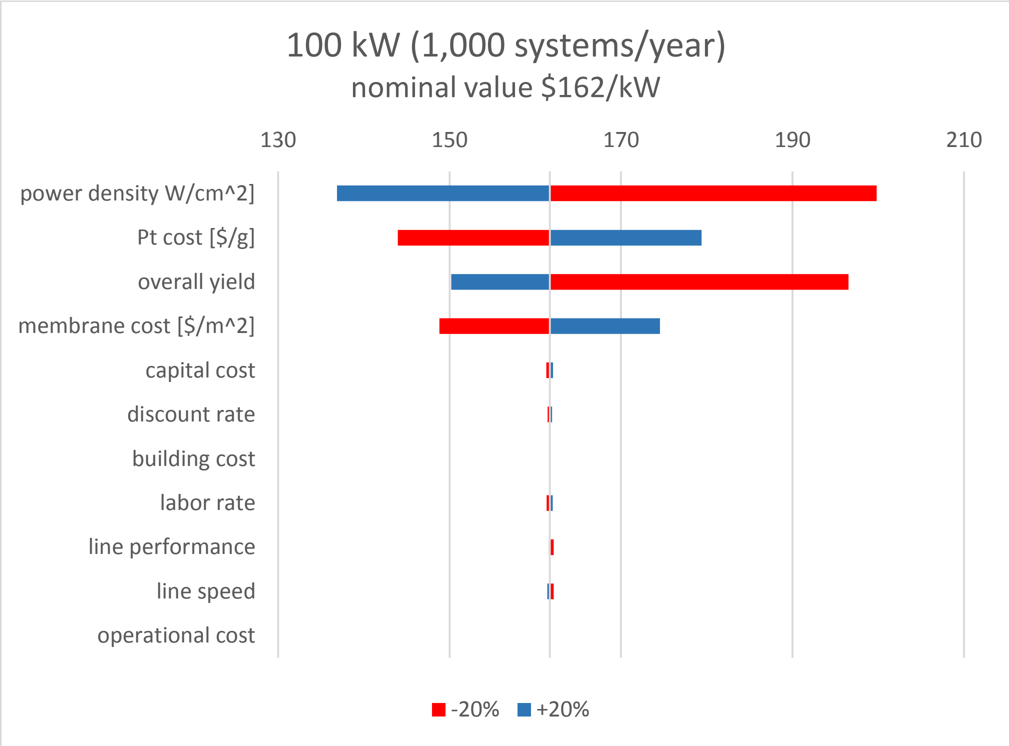


Figure 4-11 CCM sensitivity for 100 kW and 1,000 systems/year

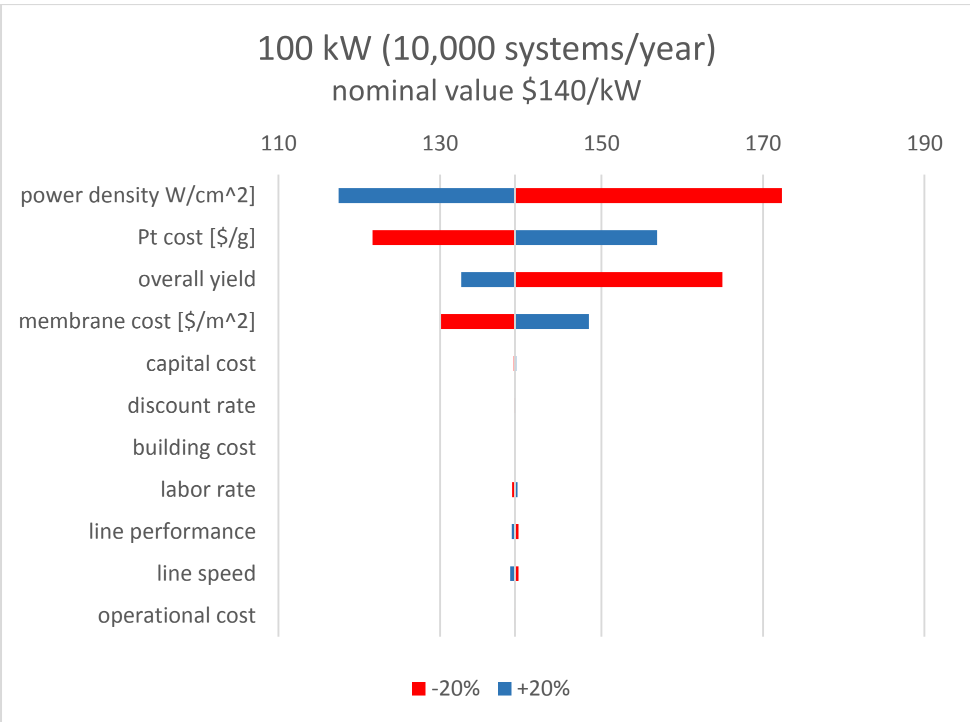


Figure 4-12 CCM sensitivity for 100 kW and 10,000 systems/year

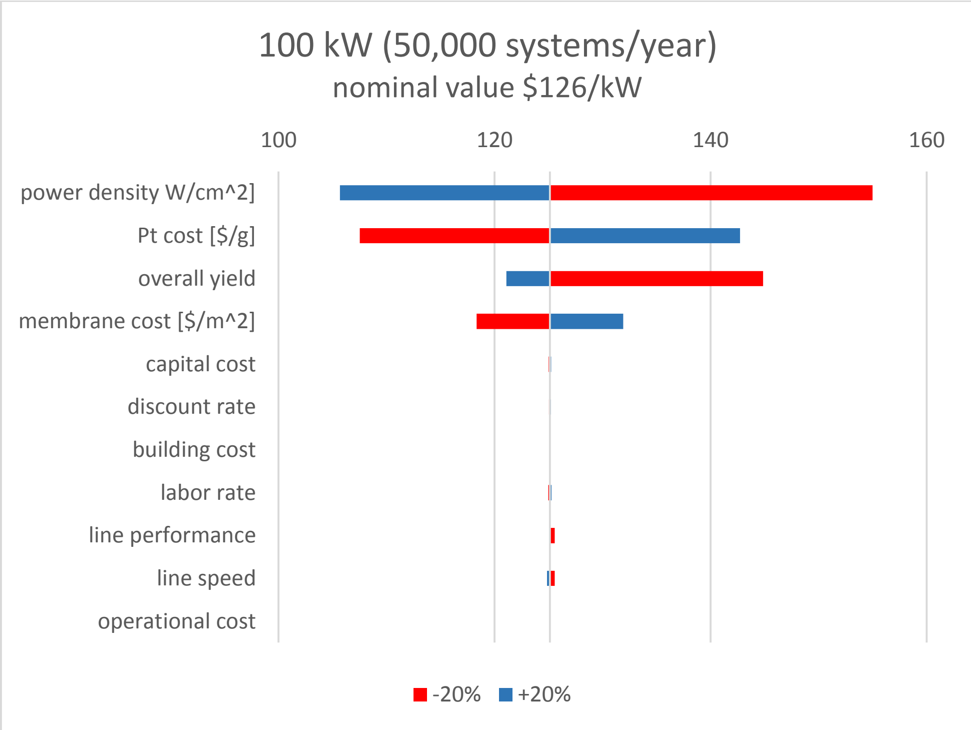


Figure 4-13 CCM sensitivity for 100 kW and 50,000 systems/year

As can be evinced from these plots, process yield and power density dominate the cost sensitivity at all production levels. Other important parameters are Pt cost and membrane cost, as they are the principal components of the material cost. Different sensitivity results are obtained if we consider low production volume (1 MW).

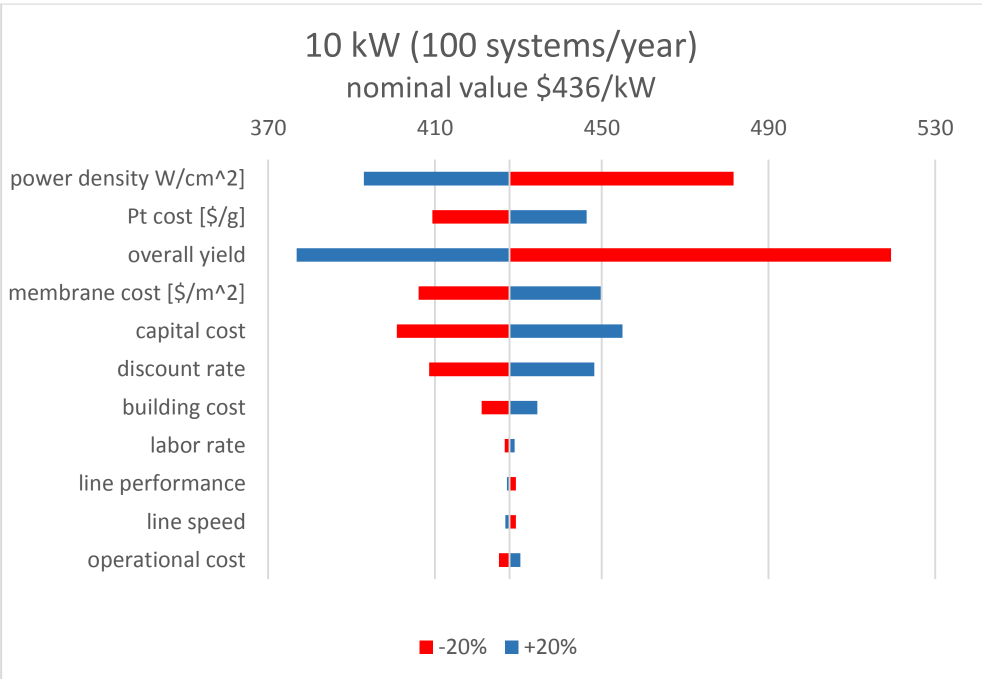


Figure 4-14 CCM sensitivity for 10 kW and 100 systems/year

In this case capital cost and discount rate are important parameters because the investment cost greatly affects low production volume.

Other CHP stack components

Other stack components costs are revised with updated general parameters and fuel cells functional specifications discussed in Chapter 2.2. Gas diffusion layers, frame/seal, carbon bipolar plates and assembly costs are analyzed in order to obtain total CHP fuel cell stack manufacturing costs.

4.2 Gas diffusion layer (GDL)

The gas diffusion layer (GDL) plays a key role for reactant gas diffusion and water management in proton exchange membrane (PEM) fuel cells. We consider the fuel cell active area of 259 cm^2 with a 0.5 cm extra length and width for bonding to the MEA (291.375 cm^2).

Table 4-24 shows GDL design parameters with material loadings and layer thicknesses.

Table 4-24 GDL Design parameters

Component	Description
Macro-porous layer	Purchased (carbon fiber paper)
Macro-porous PTFE loading	4 g/m^2 (Sinha and Yang, 2010)
MPL PTFE loading	15 g/m^2 (Sinha and Yang, 2010)
MPL Carbon Black loading	16 g/m2 (Sinha and Yang, 2010)
Carbon Fiber Paper material scrap (cutting)	90% (fixed)
Macroporous layer thickness	280um (James et al., 2010)
Microporous layer thickness	40um (Sinha and Yang, 2010, James et al., 2010)

Carbon paper is first immersed in a PTFE solution bath followed by a drying step in an IR oven. The microporous layer is formed by a spray deposition of the microporous solution followed by an IR drying step and a higher temperature-curing step.

4.2.1 GDL cost summary

Figures 4-15 and Figure 4-16 show the percentage cost breakdown for GDLs, for 10 kW and 100 kW system sizes.

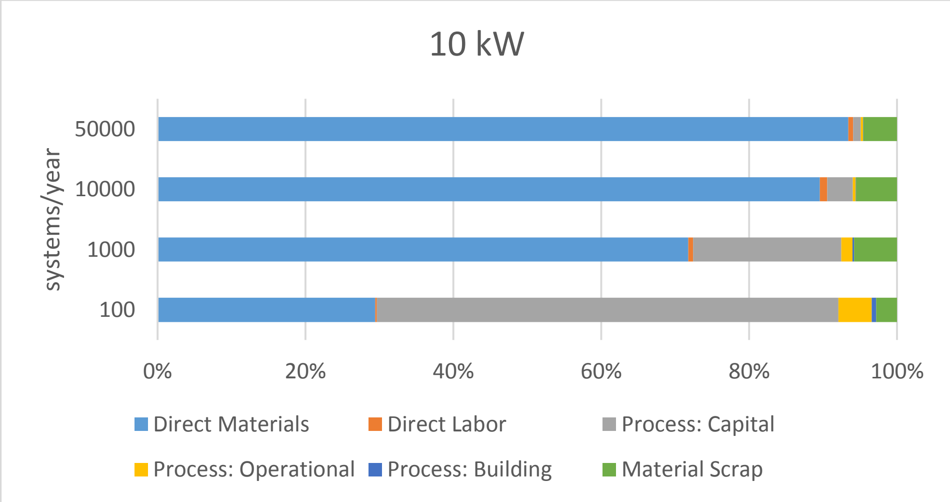


Figure 4-15 GDL cost breakdown for 10 kW system

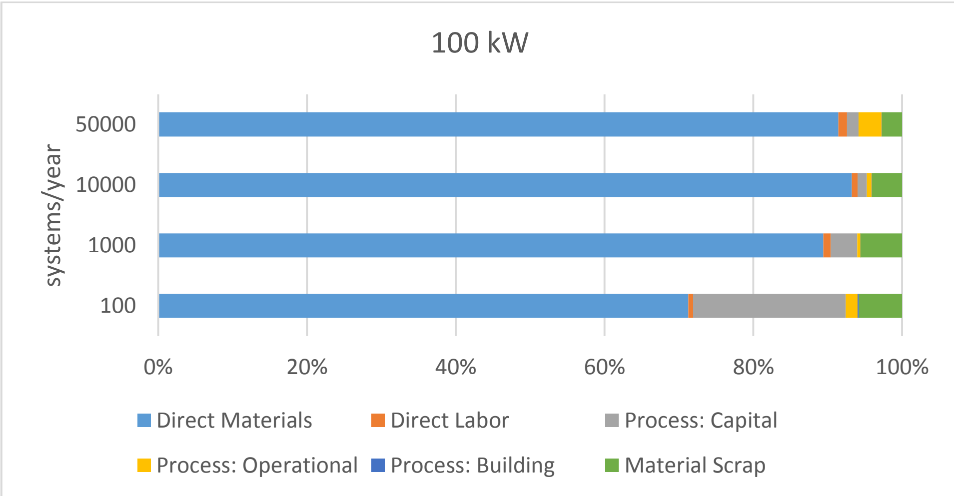


Figure 4-16 GDL cost breakdown for 100 kW system

Material costs and capital costs are the principal components of the overall GDL costs. At an annual production volume of 1 MW, capital cost makes up 65% of the total cost, and at 10 MW, 20% of overall cost. For annual production > 100 MW, direct material the principal cost component, making up about the 90% of the total cost.

Tables 4-25 and 4-26 show detailed GDL cost analysis for 10 kW and 100 kW systems, including material, labor, operational, building, capital, and scrap cost components.

Table 4-25 GDL cost results for 10 kW system

System size (kW)	10			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	105.06	79.84	57.45	41.95
Direct Labor ($/kW)	0.80	0.72	0.64	0.30
Process: Capital ($/kW)	223.12	22.32	2.23	0.47
Process: Operational ($/kW)	16.06	1.70	0.26	0.14
Process: Building ($/kW)	2.17	0.21	0.02	0.01

Material Scrap ($/kW)	10.16	6.49	3.57	2.05
Final Cost ($/kW)	357.36	111.29	64.17	44.91

Table 4-26 GDL cost results for 100 kW systemSystem size (kW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	77.47	55.85	34.30	19.86
Direct Labor ($/kW)	0.71	0.62	0.28	0.26
Process: Capital ($/kW)	22.31	2.23	0.47	0.33
Process: Operational ($/kW)	1.70	0.26	0.24	0.68
Process: Building ($/kW)	0.21	0.02	0.01	0.01
Material Scrap ($/kW)	6.32	3.49	1.50	0.60
Final Cost ($/kW)	108.72	62.47	36.79	21.73

4.3 MEA frame/seal

The approach considered in this cost study is the bordered or framed MEA, where the frame overlaps the edges and sandwiches the GDL and CCM layers as shown in Figure 4-17.

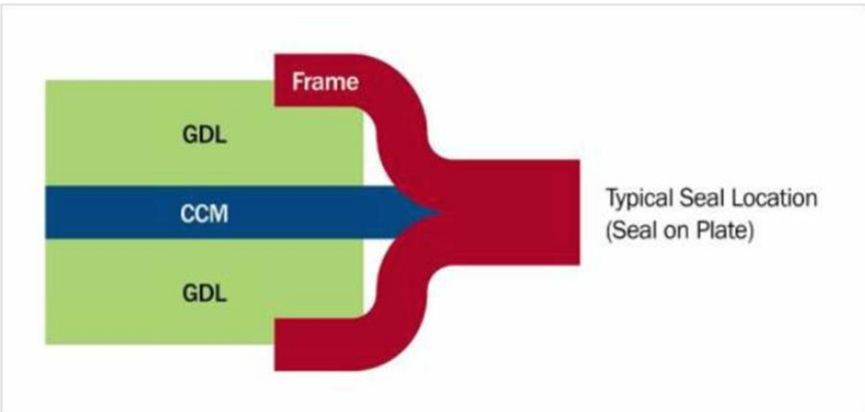


Figure 4-17 Bordered or framed MEA

The framed MEA approach is expected to be durable due to low edge stresses and is easy to align since the frame structure can be fairly rigid. However this approach leads to a waste of catalyst.

The required dimensions of the frame are derived from the functional specifications to be 38.25 cm (L) x 12 cm (H). The final material area of the frame is given by the following: original frame size – active area – channel areas, or 155 cm^2.

The MEA frame flow (Fig. 4-18) has three input roll lines for each of the MEA constituent layers (GDL Cathode, GDL Anode, and CCM) and an input roll for the frame film. The purchased frame film comes coated with an adhesive and is protected by a backing layer that is peeled away during processing. The GDL and CCM rolls are cut to size with cutters while the frame material is blank punched to expose the active area and cut to the appropriate size. A seven-axis robot “picks and places” the frame, GDL and

CCM layers to form each MEA stack. Adhesive material is assumed be pre-coated on the frame material. The MEA is hot pressed and then placed on a final punch tool to punch the manifolds and to define the final MEA size. MEAs are then placed on a stacker and the robot arm is reset. A second configuration is used for high production volumes in which the production line contains two hot presses, which leads to a 25% lower cycle time.

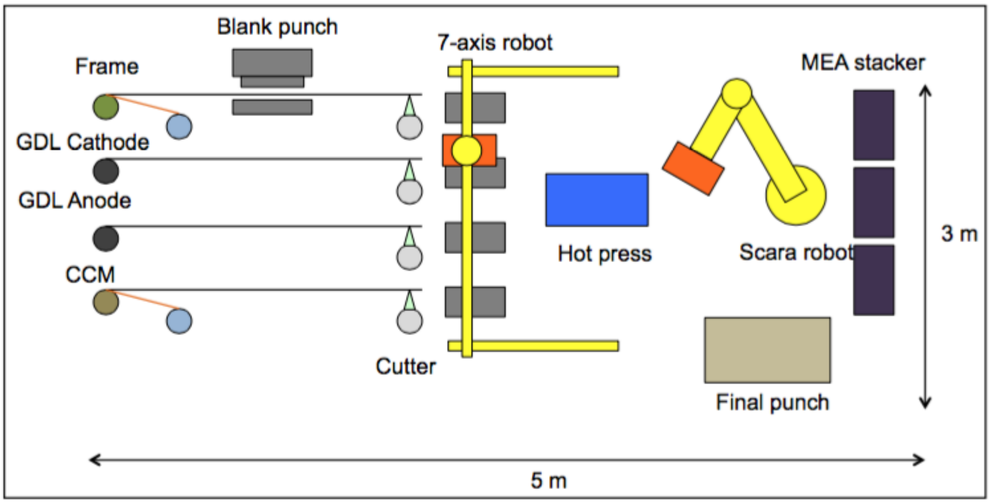


Figure 4-18 MEA process flow

4.3.1 MEA Frame/Seal cost summary

Figures 4-19 and 4-20 show percentage cost breakdown for MEA frame, for 10 kW and 100 kW annual production volumes.

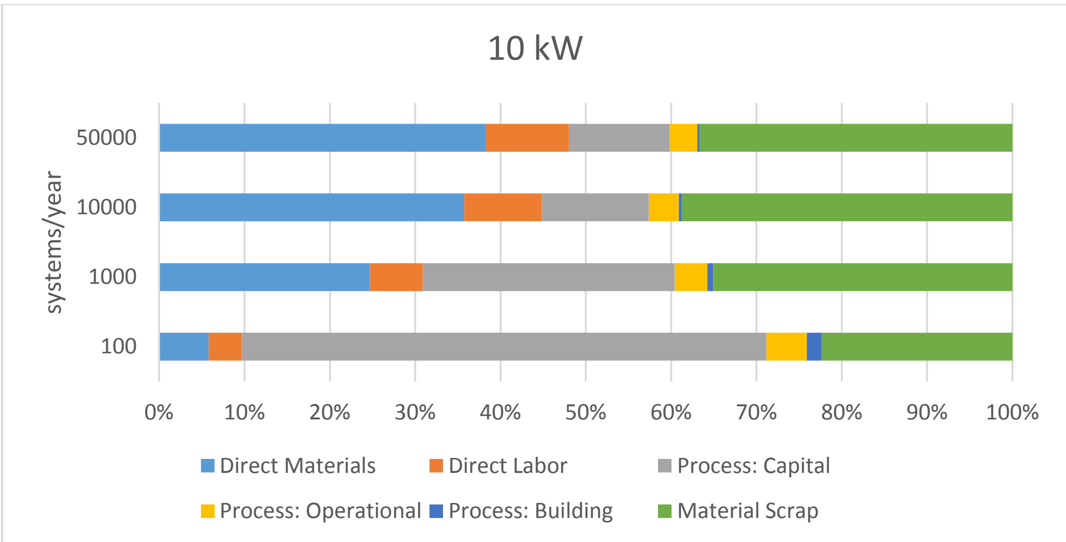


Figure 4-19 Percentage cost breakdown for MEA frame for 10 kW system

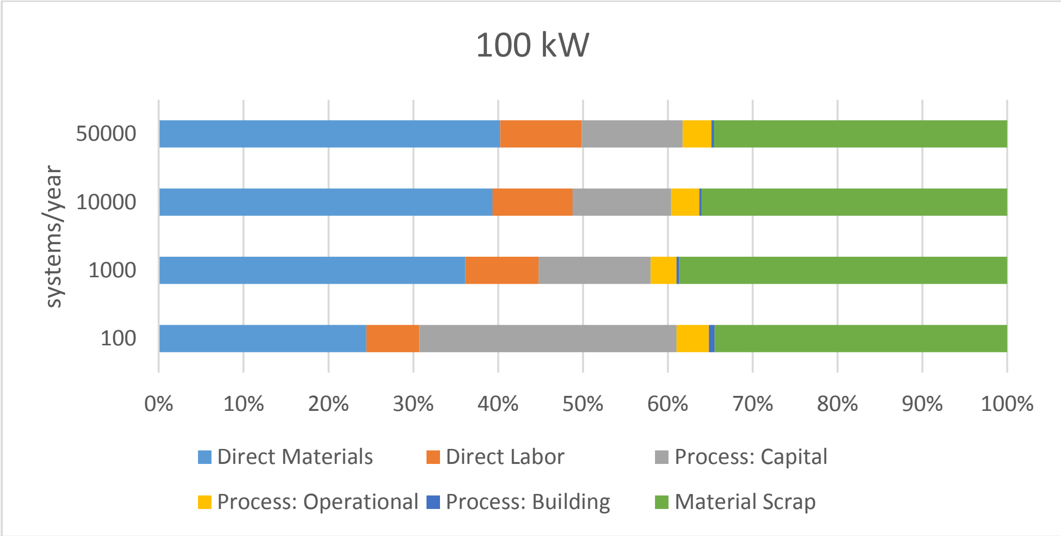


Figure 4-20 Percentage cost breakdown for MEA frame for 100 kW system

At 1 MW annual production volume capital component is the principal cost, making up 65% of the overall cost. At 10 MW equivalent volume, direct material, process capital and material scrap each make up 30% of the total cost.

At higher volumes, scrap costs are over 40% of the frame/sealing costs. Platinum recovery is assumed to be 90% but even with this high recovery percentage of Pt, scrapped MEAs are very costly since other materials will be scrapped (e.g. GDL, membrane and sealing material).

Table 4-27 and Table 4-28 show detailed cost analysis, for 10 kW and 100 kW systems, for MEA frame.

Table 4-27 Cost breakdown for MEA frame, for 10 kW system

System size (kW)	10			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	11.66	11.73	11.68	11.70
Direct Labor ($/kW)	7.88	2.97	2.96	2.97
Process: Capital ($/kW)	124.16	14.05	4.11	3.63
Process: Operational ($/kW)	9.69	1.82	1.15	0.99
Process: Building ($/kW)	3.45	0.33	0.10	0.08
Material Scrap ($/kW)	45.16	16.69	12.67	11.21
Final Cost ($/kW)	202.00	47.59	32.68	30.57

Table 4-28 Cost breakdown for MEA frame, for 100 kW system

System size (kW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	11.39	11.46	11.44	11.39
Direct Labor ($/kW)	2.89	2.74	2.74	2.73
Process: Capital ($/kW)	14.12	4.20	3.38	3.37

Process: Operational ($/kW)	1.76	0.97	0.97	0.96
Process: Building ($/kW)	0.32	0.10	0.08	0.08
Material Scrap ($/kW)	16.04	12.27	10.47	9.79
Final Cost ($/kW)	46.52	31.74	29.08	28.32

4.4 Carbon bipolar plates

Carbon bipolar plates assume an injection-molded process. Injection molding (IM) is better suited to high volume manufacturing than compression molding as it offers lower cycle times and established process technology with good dimensional control.

The total bipolar plate area (Fig. 4-21) is assumed to be 360 cm^2, including the area for MEA bonding, frame, and header channels. Maximum half-plate thickness is taken to be 1.5 mm and total BPP mass at 137.4 g.

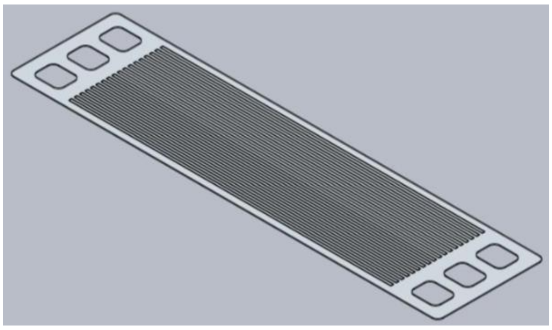


Figure 4-21 Carbon bipolar plate

The process flow is shown in Figure 4-22. Injection molding is followed by a deflashing and shot-peening step. The shot-peening step treats the surface to reduce gas permeability and become a slightly compressive layer. A screen printer is used to coat epoxy on the half plates to form bipolar plates followed by an oven-curing step and then a final inspection step.

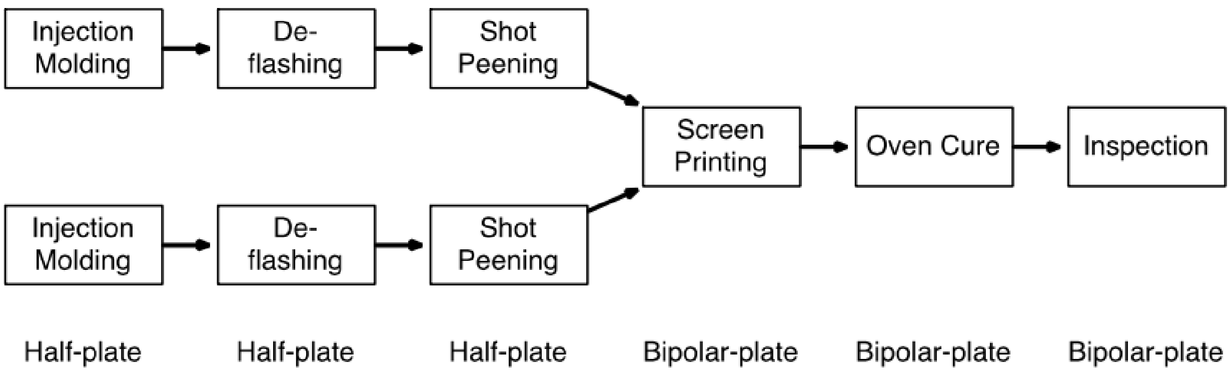


Figure 4-22 Carbon bipolar plate process line

Plate materials are assumed to be a combination of polypropylene binder with a mixture of graphite and carbon black conductive filler.

Table 4-29 Carbon bipolar plate bill of materials

Component		Material	Cost ($/kg)	Cost ($/L)
Half Plate	Binder	Polypropylene	1.597	
	Filler 1	Graphite	6.761	
	Filler 2	Carbon Black	6.35 3.833	
Bipolar Plate	Adhesive	Carbon Epoxy		97.38

4.4.1 Carbon plates cost summary

Figures 4-23 and 4-24 show percentage cost breakdown for carbon bipolar plate, for 10 kW and 100 kW annual production volumes.

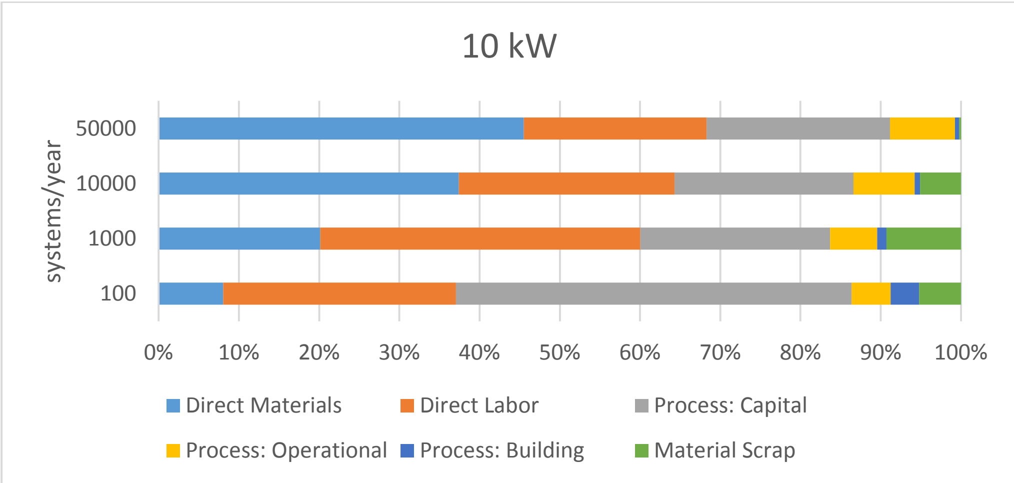


Figure 4-23 Percentage cost breakdown for carbon bipolar plate for 10 kW system

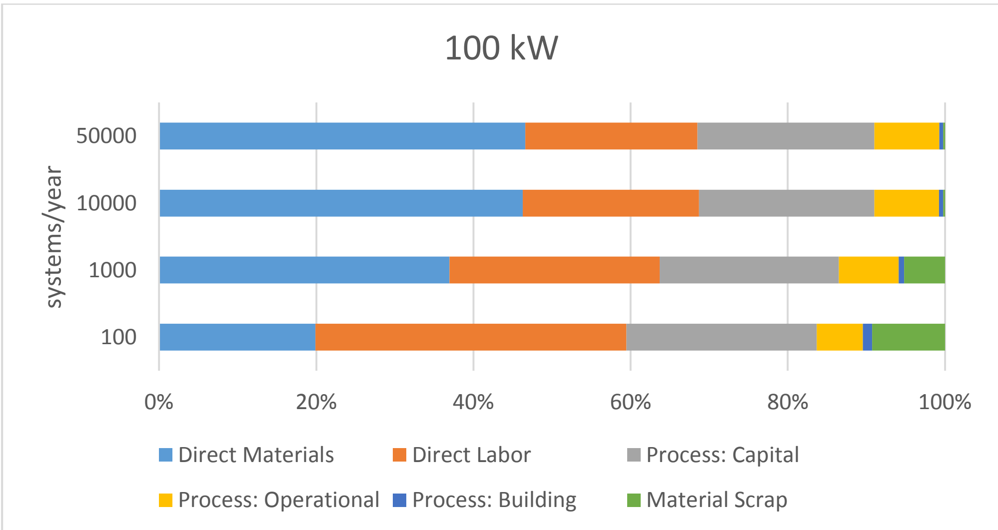


Figure 4-24 Percentage cost breakdown for carbon bipolar plate for 100 kW system

Figure 4-23 shows that at low production volume (10 kW, 100 units/year), capital cost makes up about 50% of the total cost while material cost makes up 12%. Figure 4-24 illustrates that at higher volumes (100 kW, 50,000 units/year), capital costs only make up about 25% of the total cost while material cost makes up 45%. Labor cost is an important component, constituting about 30% at all annual volume productions. At the highest volumes, the cost per plate converges to $2.60.

Table 4-30 Cost breakdown for carbon bipolar plate for 10kW system

System size (kW)	10			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/plate)	1.24	1.22	1.21	1.21
Direct Labor ($/plate)	4.49	2.41	0.87	0.61
Process: Capital ($/plate)	7.63	1.43	0.72	0.61
Process: Operational ($/plate)	0.75	0.35	0.25	0.22
Process: Building ($/plate)	0.55	0.07	0.02	0.01
Material Scrap ($/plate)	0.81	0.56	0.17	0.01
Final Cost ($/plate)	15.46	6.04	3.24	2.67

Table 4-31 Cost breakdown for carbon bipolar plate for 100 kW system

System size (kW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/plate)	1.22	1.21	1.21	1.21
Direct Labor ($/plate)	2.43	0.88	0.59	0.57
Process: Capital ($/plate)	1.48	0.75	0.59	0.59
Process: Operational ($/plate)	0.36	0.25	0.21	0.21
Process: Building ($/plate)	0.07	0.02	0.01	0.01
Material Scrap ($/plate)	0.57	0.17	0.01	0.01
Final Cost ($/plate)	6.13	3.28	2.62	2.60

Figure 4-25 shows carbon plate cost comparison ($/plate) between LBNL 2014 and this work.

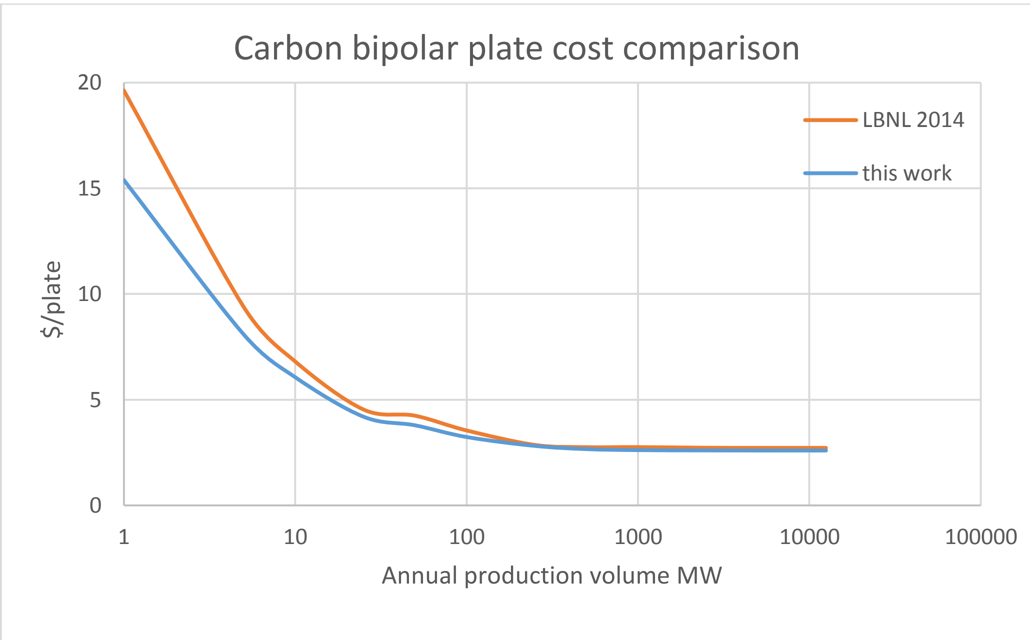


Figure 4-25 Carbon plate cost comparison ($/plate)

The greatest cost difference is at low production volume (1MW), with a cost reduction of 20%, principally due to the lower discount rate assumed in this work.

4.5 Stack assembly

This process combines the framed MEAs with the bipolar plates and assembles the fuel cell stack. We assume a manual assembly line for low production volumes, a semi-automated assembly line for medium production volumes, and a fully automated assembly line for high production volumes. The assembly process line is summarized in Figure 4-26.

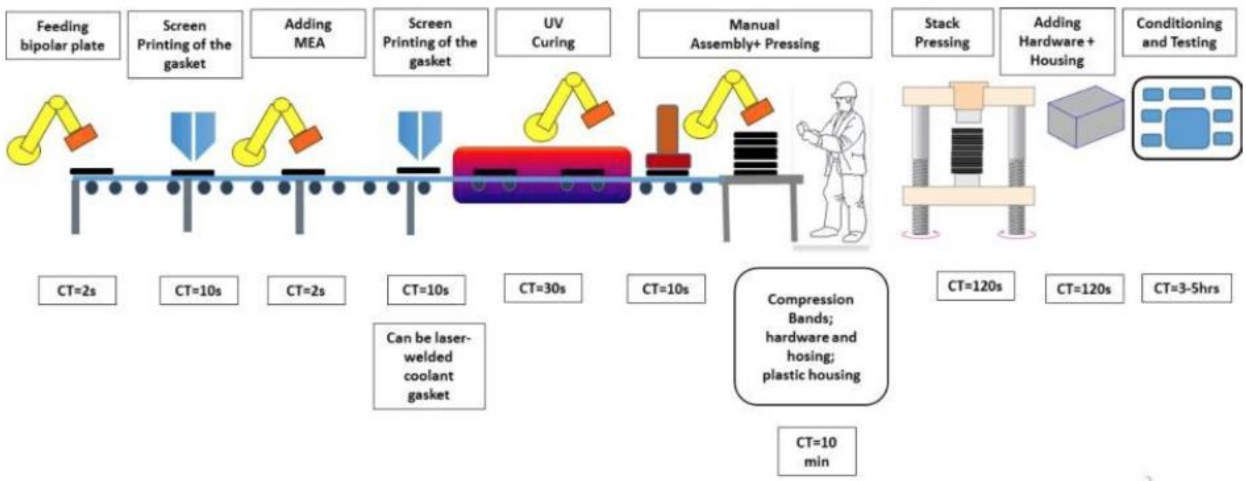


Figure 4-26 Assembly process line

Manual assembly (less than 100k units) consists of workers individually acquiring and placing each fuel cell element to form the stack (end plate, current collector, bipolar plate, gasketed MEA, bipolar plate, and so on). An entire stack is assembled at a single workstation. The worker sequentially builds the stack (vertically) and then binds the cells with metallic compression bands or tie rods. The finished stacks are removed from the workstation by conveyor belt.

Semi-automatic assembly requires less time and labor and ensures superior quality control. This is termed "semi-automatic" because the end components (end plates, current conductors, and initial cells) are assembled manually.

A fully automated assembly line is strongly recommended for very high production volumes which exceed 700k units per annum in order to reduce assembly time and to produce higher quality fuel cell stacks.

Table 4-32 Assembly line configurations

No. of MEA cells	Assembly line type	Initial capital cost estimate ($)	No. of robots per line	Cost of Robots ($)
<100k	Manual	200,000	0	0
100k-700k	Semi-automatic	500,000	2	100k
>700k	Automatic	1,000,000	7	350k

4.5.1 Stack assembly cost summary

Assembly costs are summarized in Table 4-33 and Table 4-34 for different sizes. These tables show cost breakdowns that cover materials, labor, capital, operational, and building costs.

Table 4-33 Cost breakdown for stack Assembly for 10 kW system

System size (kW)	10			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials	20.80	16.84	13.67	12.40
Direct Labor	8.85	4.43	0.79	0.79
Process: Capital	29.28	7.57	1.27	0.51
Process: Operational	2.89	0.83	0.16	0.12
Process: Building	30.78	2.73	0.25	0.10
Final Cost ($/kW)	92.61	32.40	16.13	13.91

Table 4-34 Cost breakdown for stack Assembly for 100 kW systemSystem size (kW)	100			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials	2.38	2.06	1.81	1.71
Direct Labor	0.44	0.08	0.08	0.08
Process: Capital	7.57	1.27	0.13	0.05
Process: Operational	0.75	0.13	0.02	0.01
Process: Building	1.51	1.23	0.02	0.01
Final Cost ($/kW)	12.65	4.77	2.06	1.86

Total costs for stack assembly ($/kW), along y-axis, and production volume (MW), along x-axis, are shown in Figure 4-27.

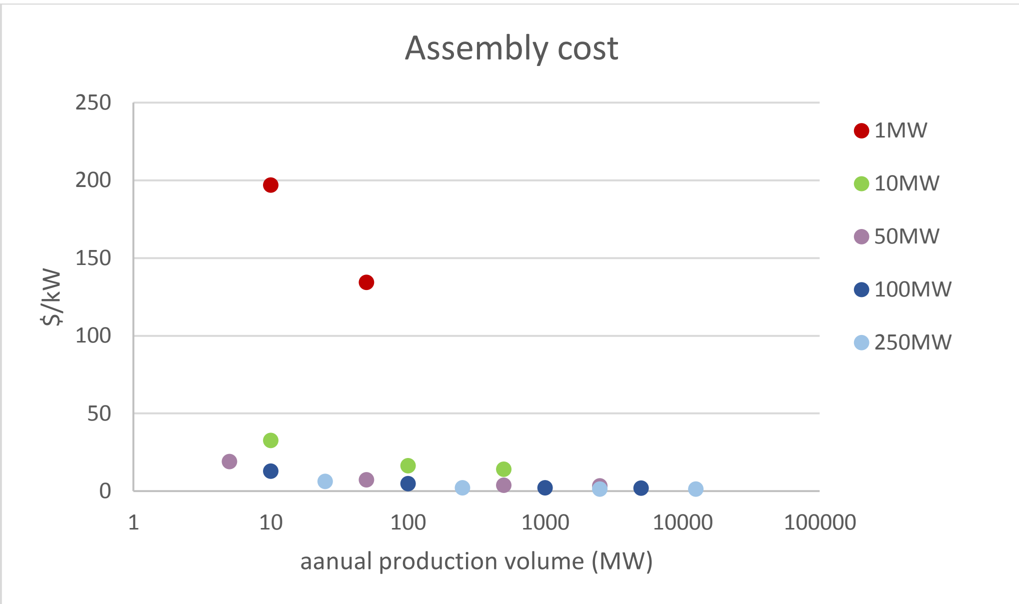


Figure 4-27 Stack assembly cost vs. production volume expressed in ($/kW).

This figure shows a decreasing cost trend with production volume; at the highest volumes, the assembly cost per kW converges to $1.20. High stack assembly costs are seen at low production volume due to several factors such as high initial cost for assembly line equipment and high floor space cost.

4.6 CHP PEM FC stack manufacturing cost results

Table 4-35 shows the overall stack costs ($/kW) for PEM FC in stationary condition, broken down by systems size and annual volume (kW).

Table 4-35 CHP PEM FC stack manufacturing costs ($/kW)

	1 kW	10 kW	50 kW	100 kW	250 kW
100 systems/year	9309.7	1340.4	596.0	465.7	376.7
1,000 systems/year	1574.8	497.2	352.4	312.9	278.9
10,000 systems/year	670.9	333.3	272.2	248.9	230.6
50,000 systems/year	453.3	283.7	239.2	218.9	202.9

The total stack costs decrease as the system size or annual volume increase. As can be seen from Figure 4-28 and Figure 4-29, there is a greater cost reduction increasing system size than annual volume.

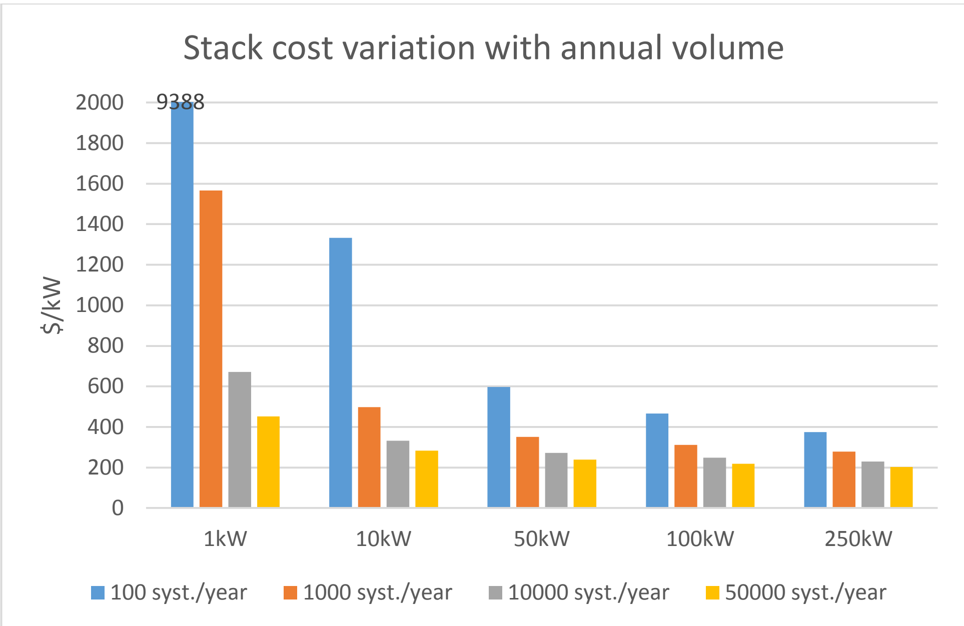


Figure 4-28 Stack manufacturing cost variation with annual production rate ($/kW)

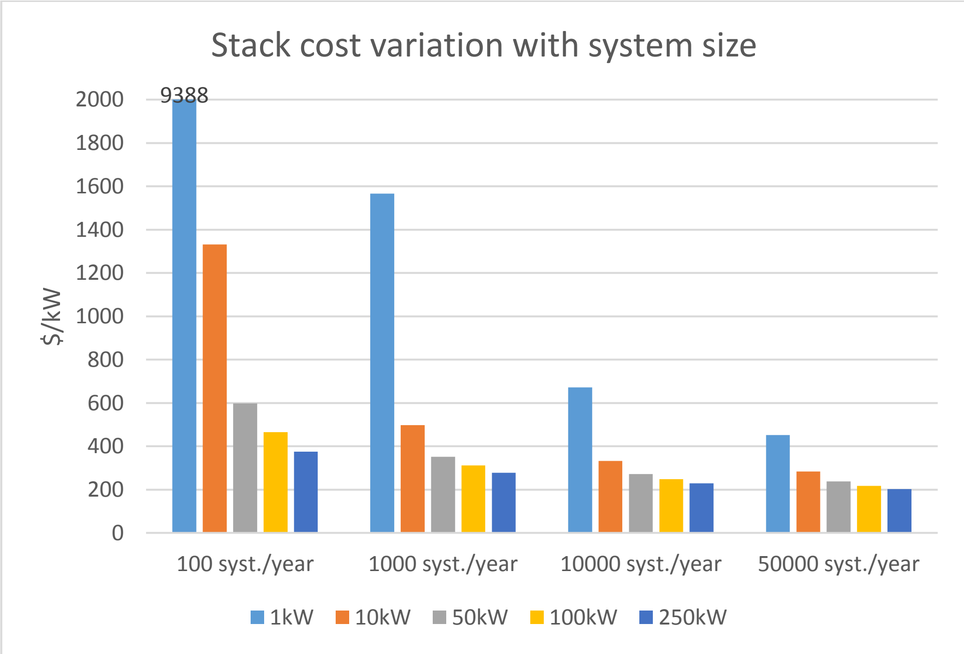


Figure 4-29 Stack manufacturing cost variation with system size ($/kW)

Detailed stack costing results are shown below for 10 kW and 100 kW stacks:

- Overall stack costs per kWe as function of production volume (100, 1,000, 10,000, and 50,000 systems per year) are shown in Figure 4-30 and Figure 4-31.

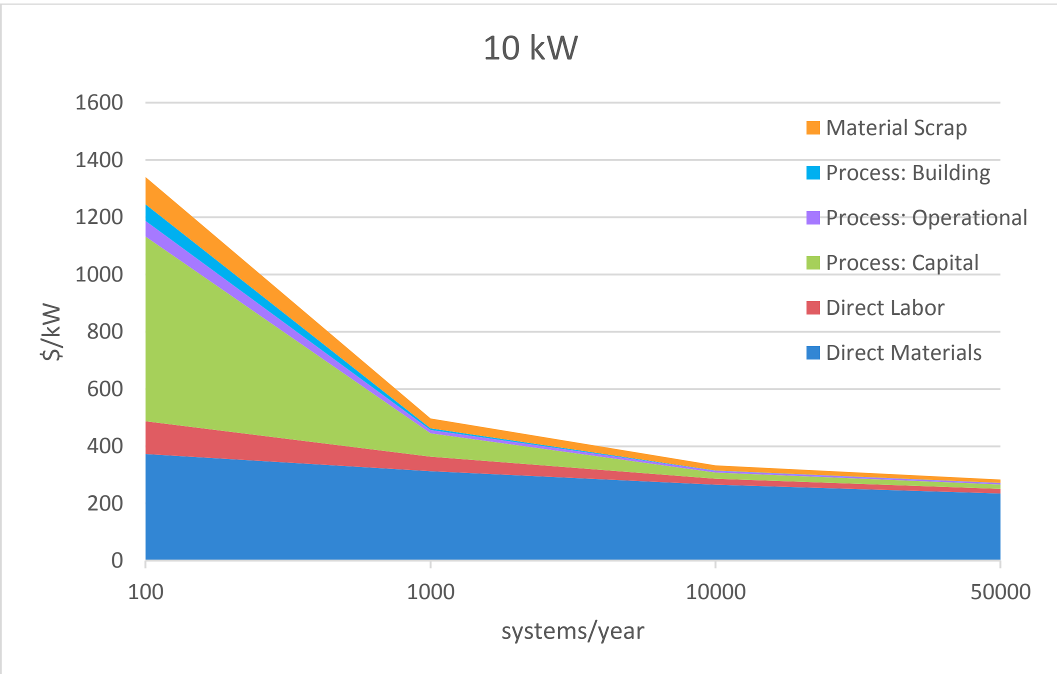


Figure 4-30 PEM FC stack cost as a function of annual production volume (systems/year) for 10 kW system

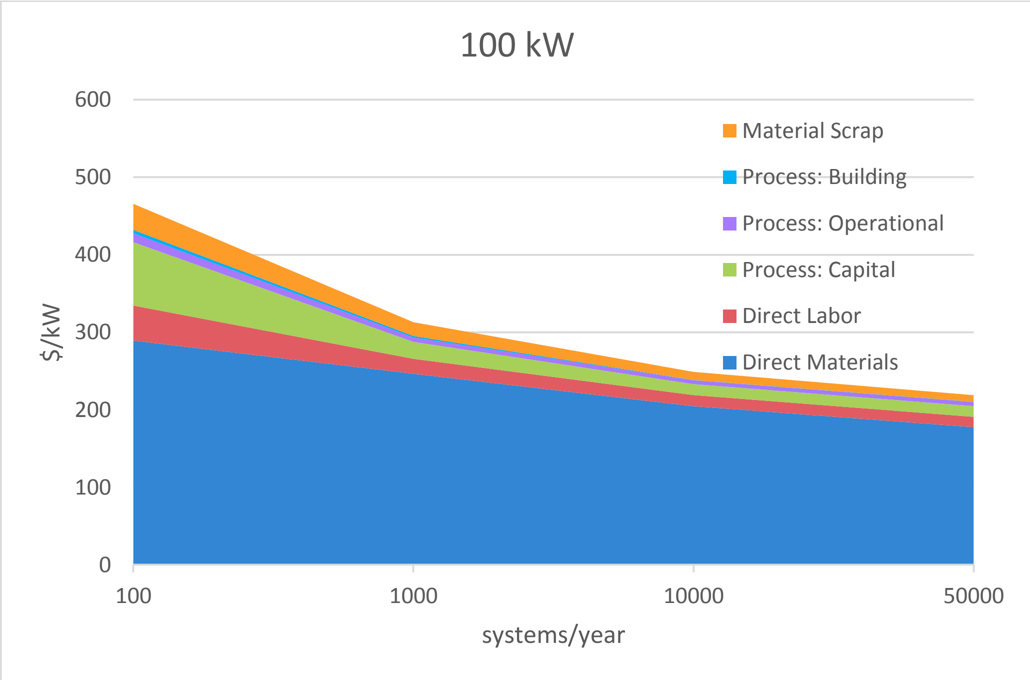


Figure 4-31 PEM FC stack cost as a function of annual production volume (systems/year) for 100 kW system

Figure 4-30 and Figure 4-31 show that material costs dominate at high volumes. At low volumes, capital cost also has a strong impact on overall stack cost because of lower machine utilization.

- Breakdown of the stack cost in a stack components level (Figure 4-32 and Figure 4-33)

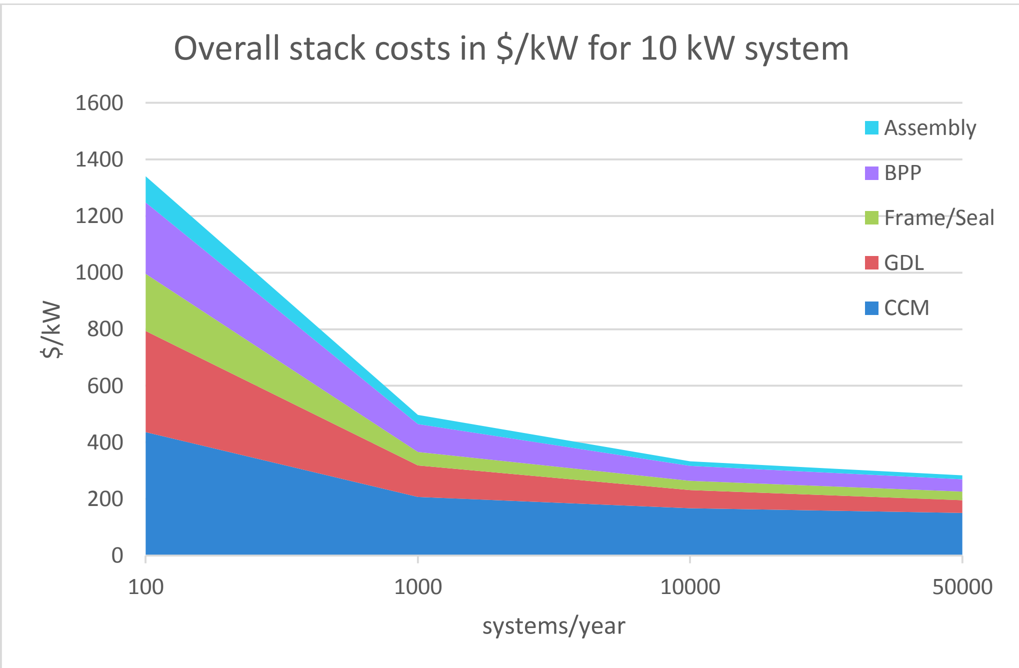


Figure 4-32 Breakdown of the stack cost in a stack components level for 10 kW system

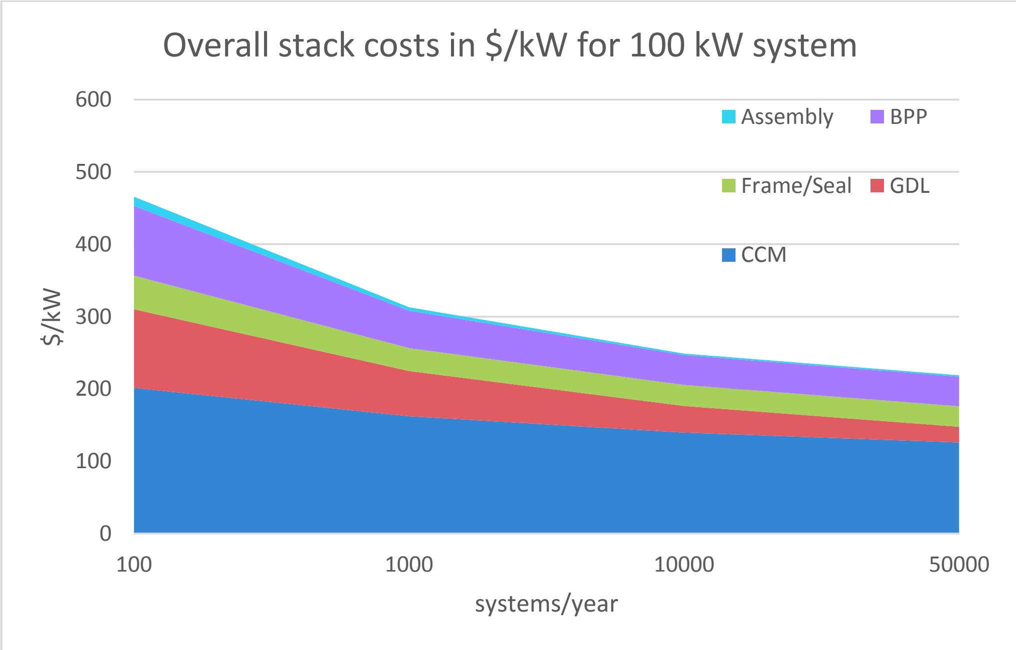


Figure 4-33 Breakdown of the stack cost in a stack components level for 100 kW system

The CCM cost remains almost constant at high production due to the Pt cost component. Carbon plates, gas diffusion layers, frame and assembly costs decrease when annual volume increases. Assembly costs are negligible, compared to the overall costs, at high production rate. Disaggregation of stack cost by relative percentage of stack components costs to overall stack cost are shown in Figure 4-34 and Figure 4-35.

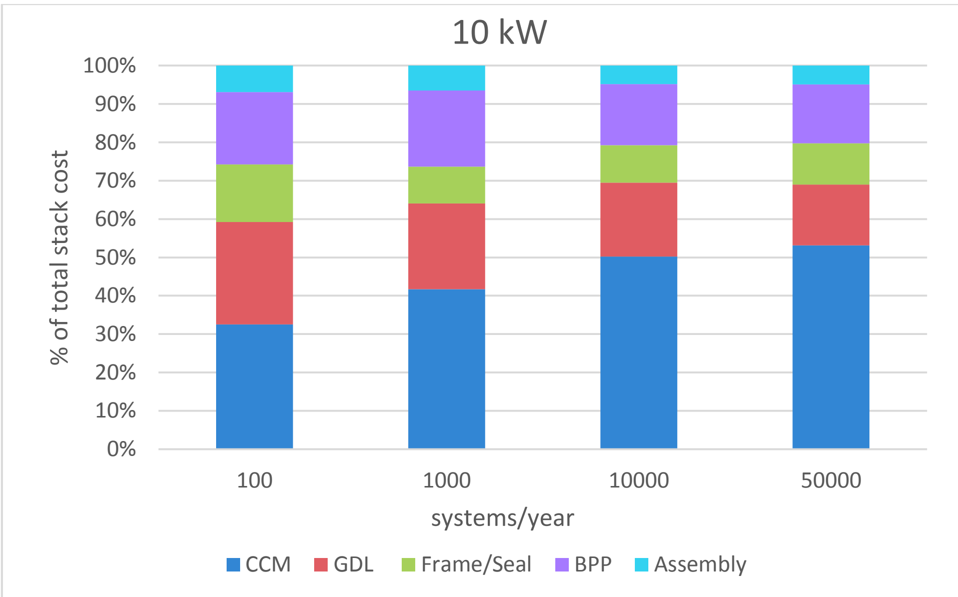


Figure 4-34 Disaggregation of stack cost by relative percentage of components cost for 10 kW system

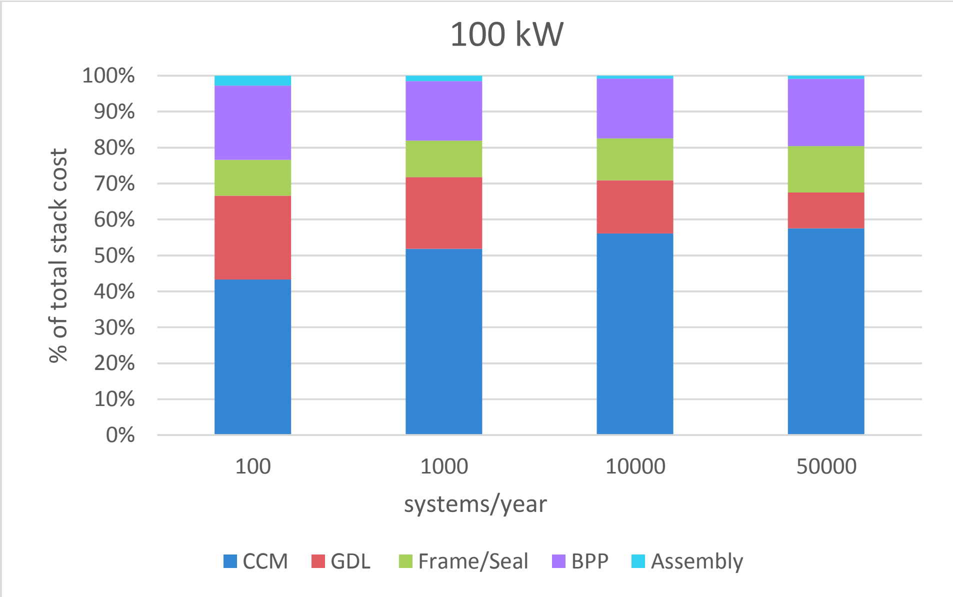


Figure 4-35 Disaggregation of stack cost by relative percentage of components cost for 100 kW system

Figure 4-34 and Figure 4-35 show that CCM constitutes the principal cost item, more than the half of the stack cost above an annual production of 100 MW (1,000 systems of 100 kW power). Bipolar plates, frame/seal and gas diffusion layers constitute each about 10-20% of stack cost. Assembly costs constitute the 2-5% of the overall cost.

4.7 Cost results comparison

As validation of this analysis, stack cost is compared to the previous work made by Strategic Analysis [2] and the LBNL 2014 cost study [1].

4.7.1 SA cost study

Figure 4-36 compares the cost results of this work to an earlier SA cost study

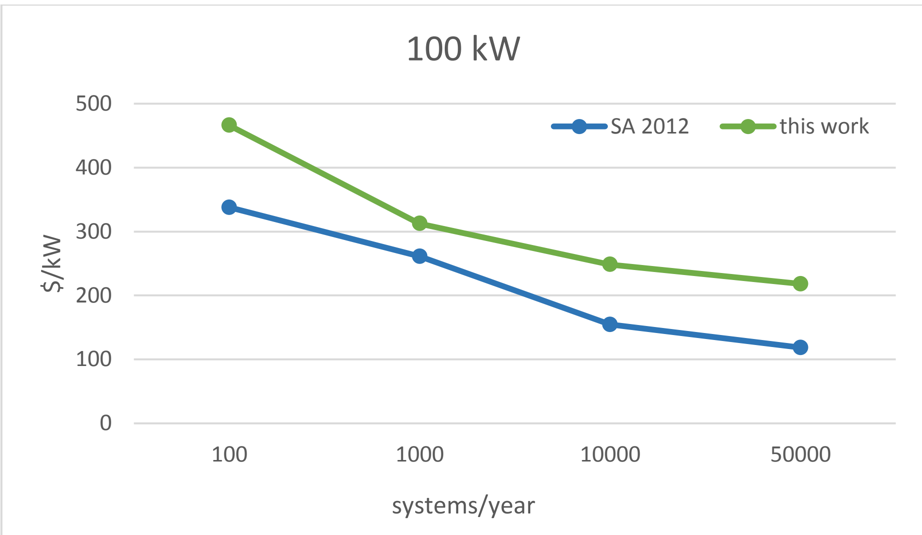


Figure 4-36 100 kW CHP stack cost comparison to SA 2012 [2].

Figure 4-36 shows that the two studies yield similar results with this work yielding higher cost values at all data points. The higher stack cost seen in this work is due to lower yield assumption, higher platinum loading, higher platinum cost and greater detail in tooling capital costs.

4.7.2 LBNL 2014 cost study

Figure 4-37 and Figure 4-38 show the stack cost ($/kW) comparison between this work and LBNL 2014 results for 10 kW and 100 kW system.

Table 4-36 CHP Stack Cost ($/kW) Comparison

CHP Stack Cost ($/kW) Comparison				
systems/year	100	1,000	10,000	50,000
10 kW LBNL 2014	1,790	590	370	311
10 kW this work	1,340	497	333	284
100 kW LBNL 2014	556	346	273	238
100 kW this work	466	313	249	219

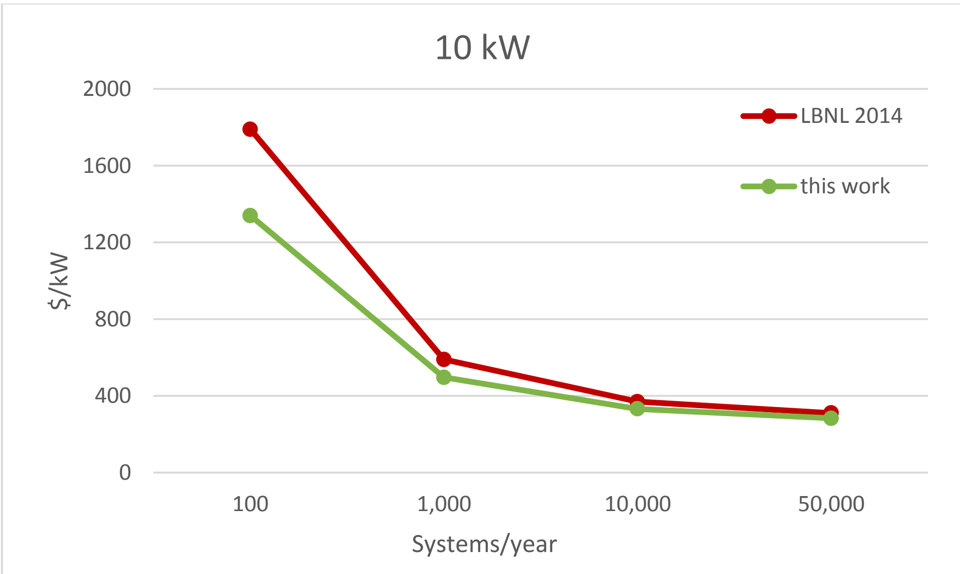


Figure 4-37 10 kW CHP stack cost comparison to LBNL 2014

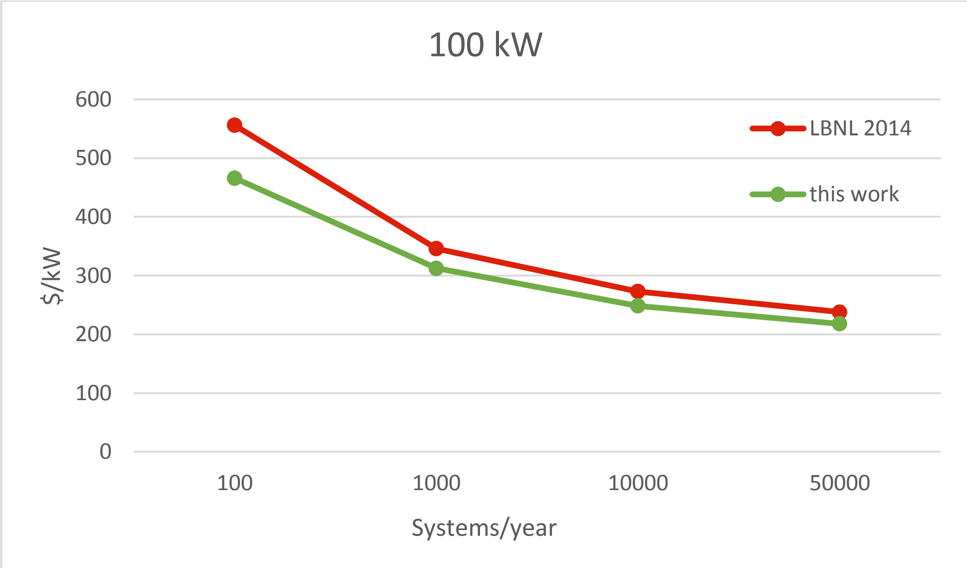


Figure 4-38 100 kW CHP stack cost comparison to LBNL 2014.

The most appreciable cost difference is at low annual production volume principally due to a lower capital cost, because the lower discount rate assumed for this work. At 100 systems per year the cost reduction is equal to 25% (from $1790/kW to $1340/kW) for 10kW system and 16% (from $556/kW to $466/kW) for 100kW system.

4.8 Sensitivity analysis

A sensitivity analysis at the stack level is performed for 100 kW systems at different production volumes. The impact to the stack cost cost in $/kW is calculated for a ±20% change in the sensitivity parameter being varied.

Module process yield and power density are the most sensitive cost assumptions. Pt price and Nafion membrane price are among other important factors. The discount rate and capital cost are not large factors at high volume since material costs dominate the overall cost. Note that yield becomes less sensitive at high volume for two reasons: (1) overall yield is assumed to be very high at high volume (95%), and (2) material costs dominate at high volume and a significant portion of material costs are recovered from rejected material.

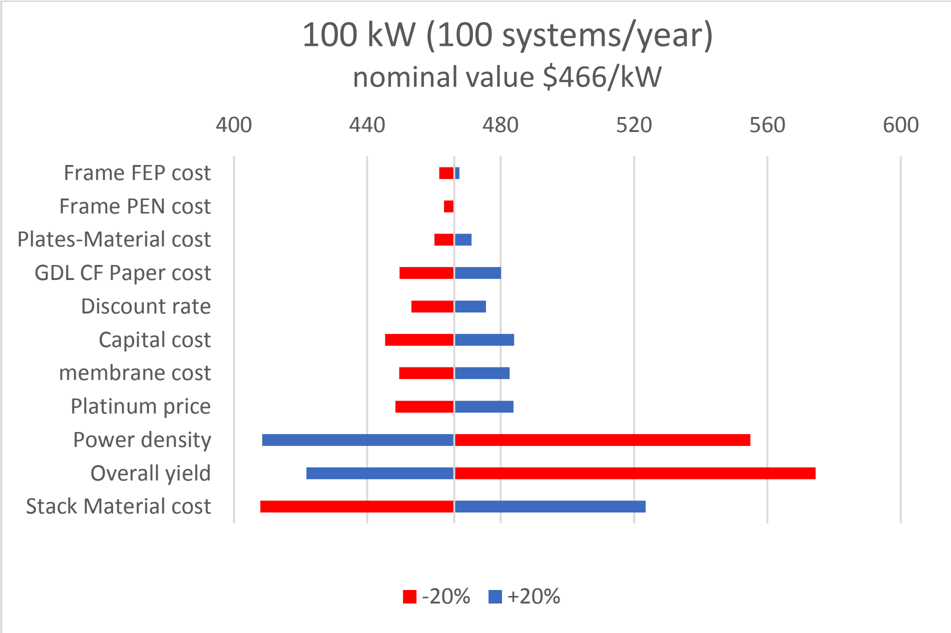


Figure 4-39 Sensitivity analysis for 100 kW CHP system at 100 systems/year.

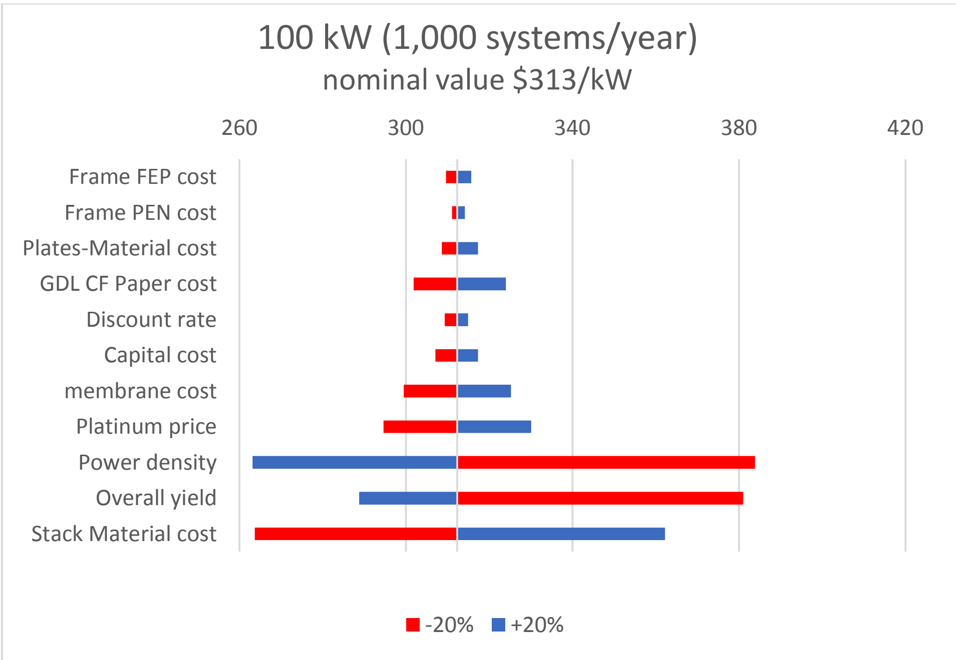


Figure 4-40 Sensitivity analysis for 100 kW CHP system at 1,000 systems/year.

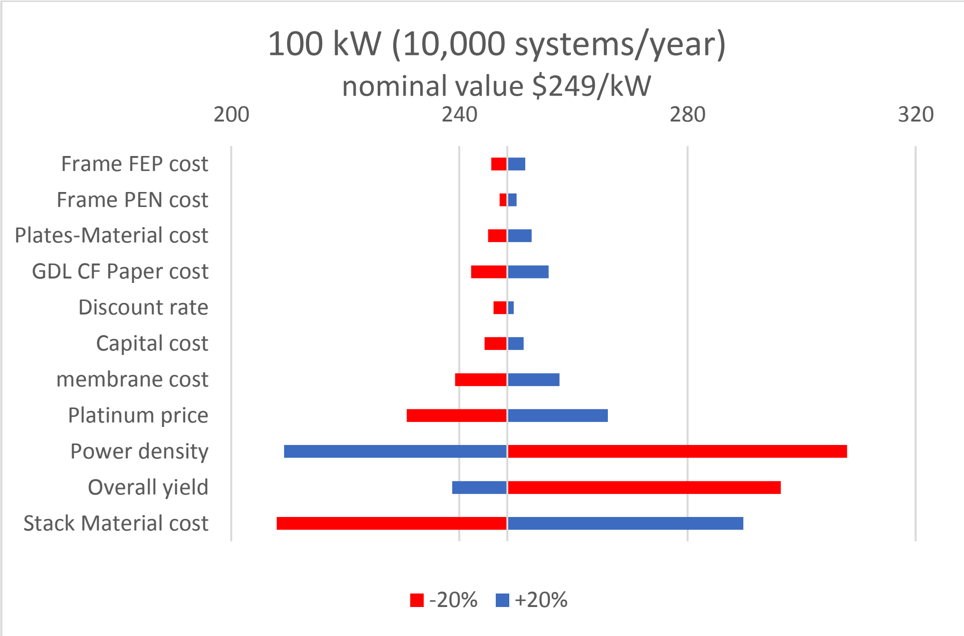


Figure 4-41 Sensitivity analysis for 100 kW CHP system at 10,000 systems/year.

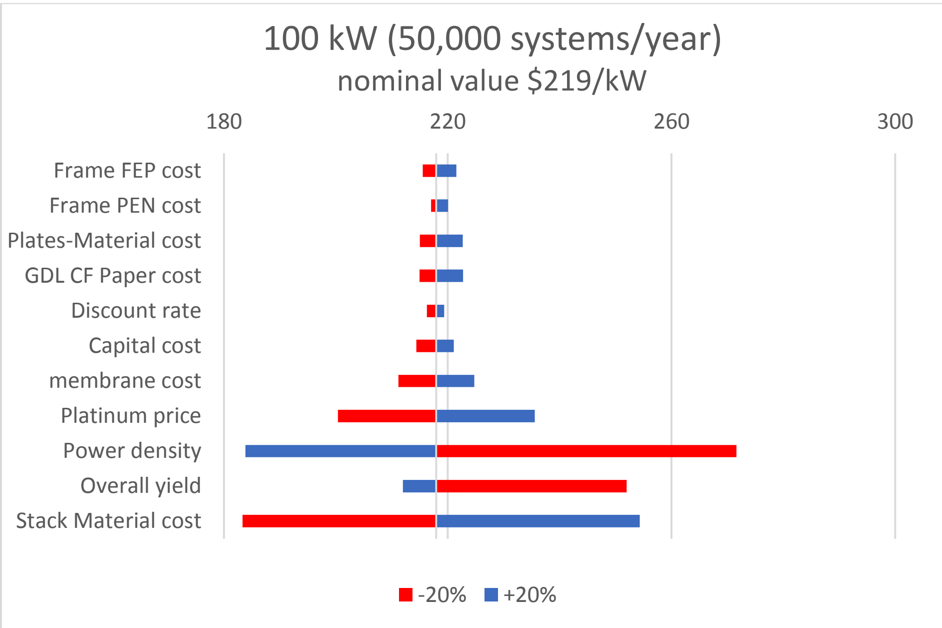


Figure 4-42 Sensitivity analysis for 100 kW CHP system at 50,000 systems/year.

Stack material cost sensitivity becomes more relevant going to high production volumes; conversely stack capital cost sensitivity becomes more negligible at high production volumes. These trends are depicted in Figure 4-43 and Figure 4-44 for a 10 kW system. They represent the percentage deviation from the nominal stack cost due to material and capital cost sensitivity, for different annual production volumes.

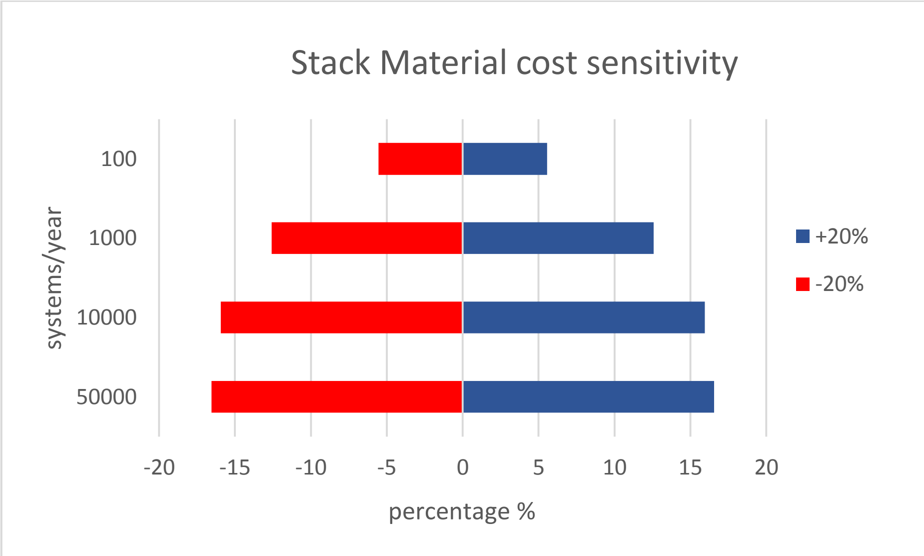


Figure 4-43 Percentage cost deviation due to material cost sensitivity for 10 kW system

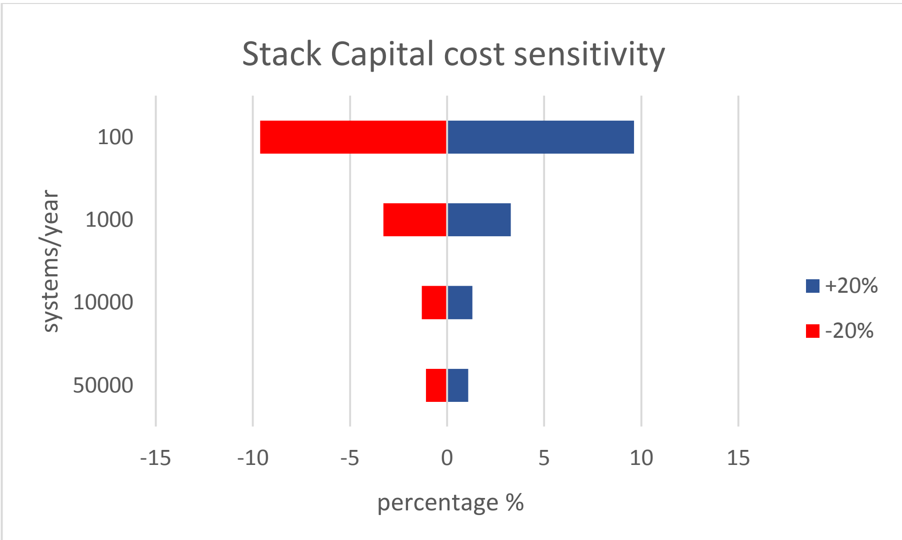


Figure 4-44 Percentage cost deviation due to capital cost sensitivity for 10 kW system

As can be evinced from sensitivity plots, module process yield has a great impact on stack cost. To better appreciate how this parameter affects the total cost, a process yield analysis for 100 kW and 10,000 systems/year is performed (Figure 4-45 and 4-46).

This yield analysis, however, assumes a uniform process yield throughout all stack modules (CCM, GDL, frame, bipolar plates), which is not exactly the case for the base costing case that is detailed above but is illustrative of the overall cost sensitivity to yield. Figure 4-46, in addition to stack costs, assumes a corporate markup of 50%.

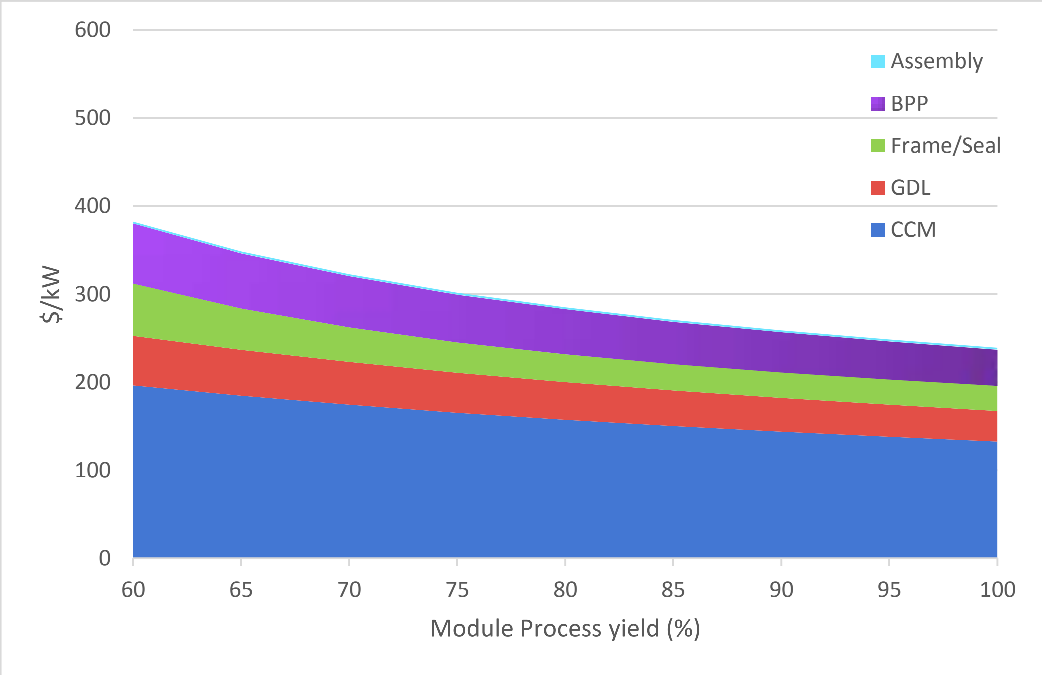


Figure 4-45 100 kW (10,000 units/year) direct manufacturing stack cost vs. yield

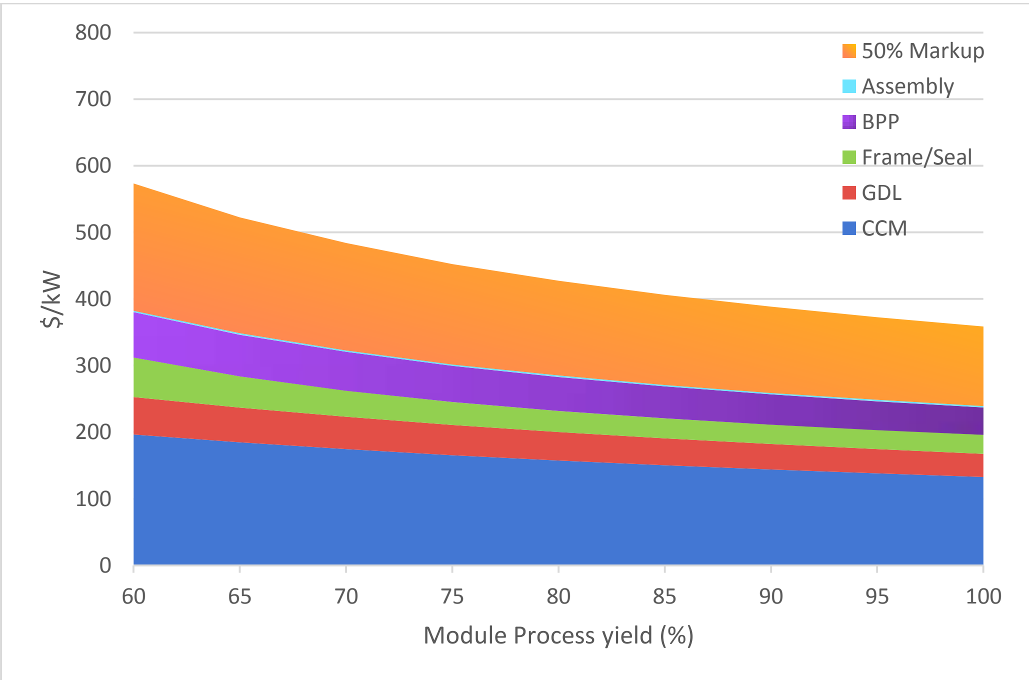


Figure 4-46 100 kW (10,000 units/year) stack cost with markup vs. yield

By varying the process yield from 60 to 99.5%, the stack cost, without markup, decreases from \$380/kW to \$240/kW (35% of cost reduction). Stack costs, with a markup of 50%, range from \$570/kW (60% process yield) to \$360/kW (99.5% of process yield). This shows that, in addition to increasing production volume, improved process yield also has a large effect on stack cost.

Figures 4-47 and 4-48 show stack cost results with different process yields, without the platinum recycle assumption (90% of Pt material is recovered and 10% of Pt is assumed to cover the cost of recovery).

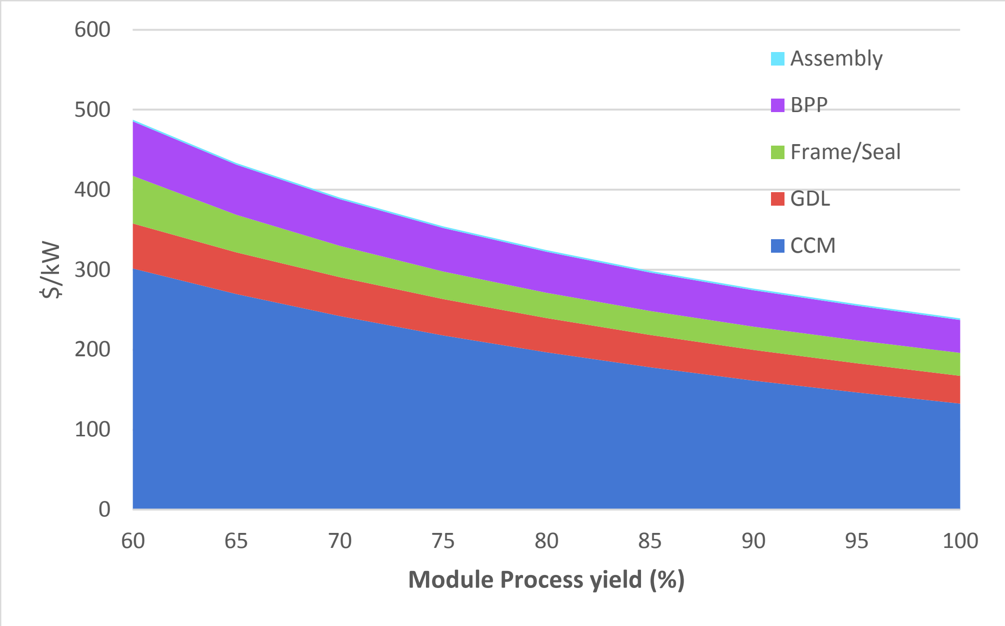


Figure 4-47 100 kW (10,000 units/year) direct manufacturing stack cost vs. yield (without Pt recycle)

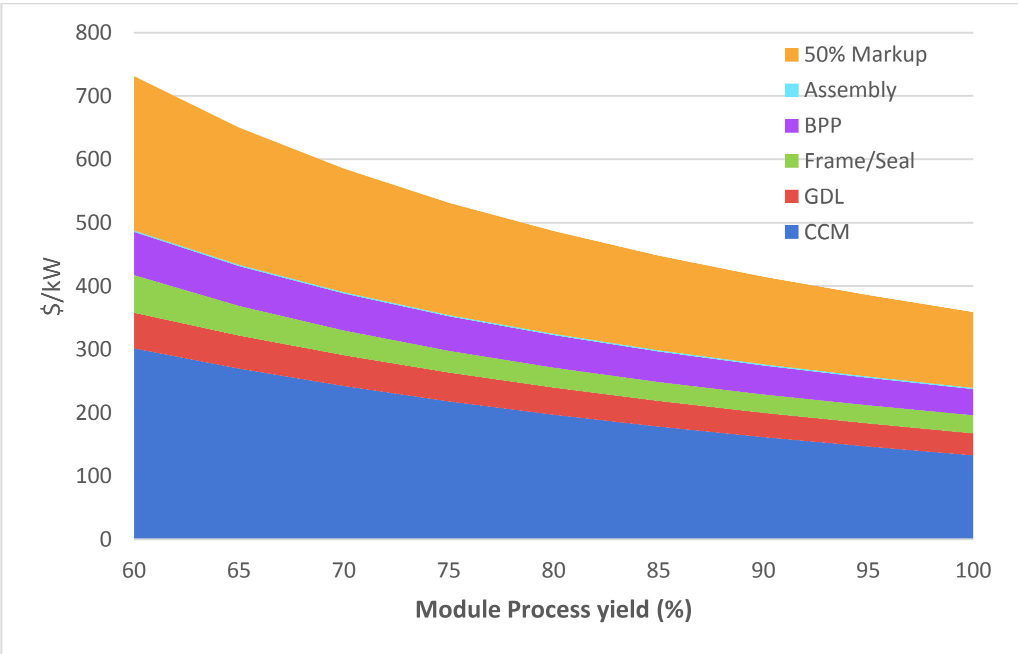


Figure 4-48 100 kW (10,000 units/year) stack cost with markup vs. yield (without Pt recycle)

The shape of CCM cost component is steeper than the previous case with Pt recycling. Stack costs, without markup, range from about $490/kW (60% of process yield) to about $240/kW (99.5% process yield).

5 Balance of Plant and System Costs

This chapter analyzes the balance of plant of a PEM FC system and compares the total system cost to DOE targets. The fuel cell system (FCS) consists primarily of the fuel cell stack and the balance of plant (BOP) components. The BOP includes items such as valves, compressors, pumps, wiring, piping, meters, controls etc. that are associated with the complete operation of the fuel cell system.

Six major areas make up the BOP and are listed below:

- *Fuel Processing Subsystem*

The fuel processing subsystem consists of a fuel processor for producing hydrogen fuel from natural gas. The fuel processing subsystem is comprised of components associated with the operation of the fuel reformer, which includes parts such as sensors, controls, filters, pumps, and valves.

- *Air Subsystem*

The air subsystem consists of components associated with oxidant delivery to the fuel cell stack. Major components in this subsystem are storage tanks, compressor, motor, piping, and manifolds.

- *Coolant and Humidification Subsystems*

The coolant subsystem consists of components associated with water management in the FCS, including humidification of membranes. These include: tank, pump motor, piping and external cooling motor.

- *Power Subsystem*

The power subsystem contains components required for powering the system and conditioning the output power. The system includes: inverter, transistor, transformer, power supply, relays, switches, fuses, resistors, Human Machine Interface (HMI), amplifiers, and cables.

- *Controls and Meters Subsystem*

This controls and meters subsystem contains system controls-related components for system operation and equipment monitoring. This subsystem includes items such as the variable frequency drive (VFD), sensors, meters, and virtual private network (VPN) system.

- *Miscellaneous Subsystem*

The miscellaneous subsystem comprises external items outside of the stack that provides support, structure, and protection for the FCS. These items include: tubing, enclosure, fasteners, fire/safety panels, and labor.

- *Thermal management*

The thermal management consists of the heat exchangers, for for water heating and space heating, and the condenser.

5.1 Balance of plant results

Table 5-1 displays the component breakdown of BOP subsystem costs for the 10 kW and 100 kW CHP system with reformate fuel at production volume of 1,000 systems per year. For the 100 kW CHP system, the external cooling motor dominates the coolant subsystem, accounting for approximately half of the subsystem cost. The cost of the power subsystem is dominated by the power inverter, which accounts for approximately 69% of the subsystem cost. In the thermal management subsystem, costs are driven by the heat exchanger for space heating. The air subsystem contains fairly balanced costs among each component. Enclosure and Labor cost dominate the miscellaneous components, accounting respectively for the 31% and 58% of the subsystem cost.

Table 5-1 BOP subsystem costs of CHP system with reformate fuel (10 kW, 100 kW) for 1,000 systems/year

CHP System with Reformate Fuel Component Breakdown (for 1000 systems/year)	**10 kW**	**100 kW**
	$/kW	
Fuel Processing Subsystem		
	602	231
Air Subsytem		
Air Humidfier Tank Humidification Pump Air Pump Compressor Radiator Manifolds Air Piping Air Intake Pre Filter Air Intake Filter	246	59
Coolant Subsystem		
Coolant Tank Coolant Pump Motor Coolant Piping External Cooling Fan/ Motor Propylyne Glycol	105	59
Thermal Management		
Heat Exchanger (water heating) Heat Exchanger (space heating) Condenser	182	76
Power Subsystem		
Power Inverter Braking Transistors Transformer Power Supply Relays Switches Fuses HMI Bleed Resistor Ethernet Switch Power Cables (2W and 4W) Voltage Transducer Power Conditioning Spare Parts	421	249
Controls/Meters		
Variable Frequency Drive Thermosets CPU Flow Sensors	231	66

Pressure Transducer		
Temperature Sensors		
Hydrogen Sensors/Transmitter and Controller		
Sensor Head		
VPN/ Gateway/Data Storage Computer		
Miscellaneous Components		
Tubing		
Wiring		
Enclosure		
Fasteners	390	154
Fire/Smoke Detector		
Hydrogen Leak Alarm		
Labor Cost		
Total $/kW	**2177**	**894**

Figure 5-1 and 5-2 show the subsystem breakdown for the 10 kW and 100 kW CHP system with reformate fuels for various production units.

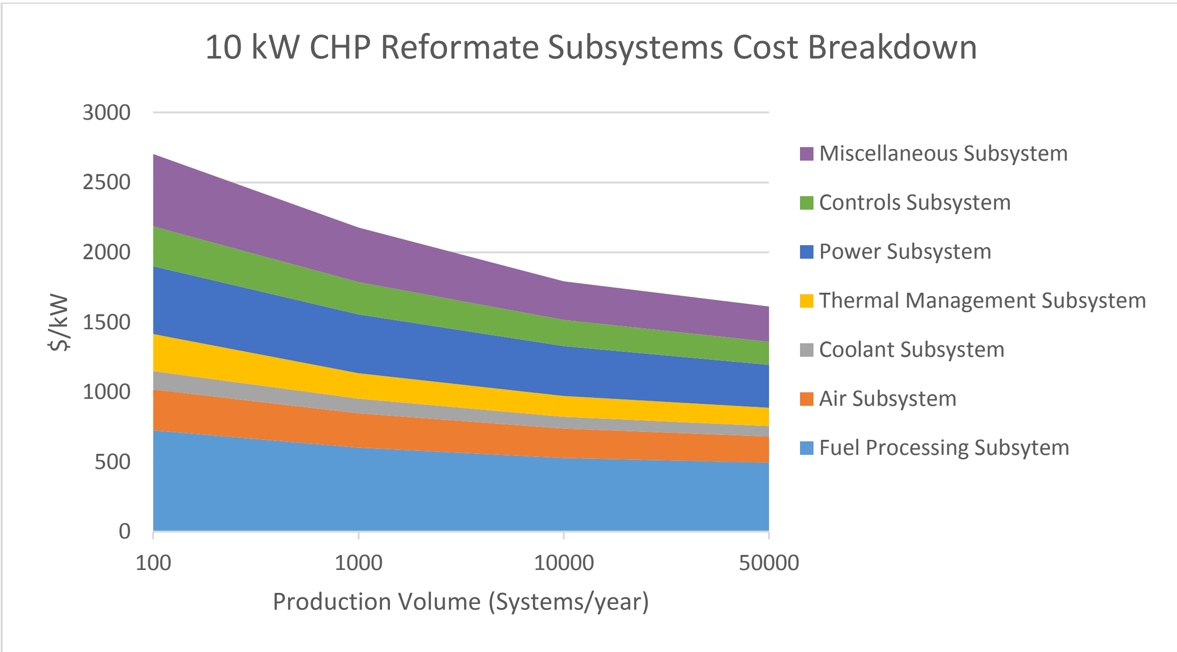


Figure 5-1 Subsystem cost breakdown of 10 kW CHP system with reformate fuel

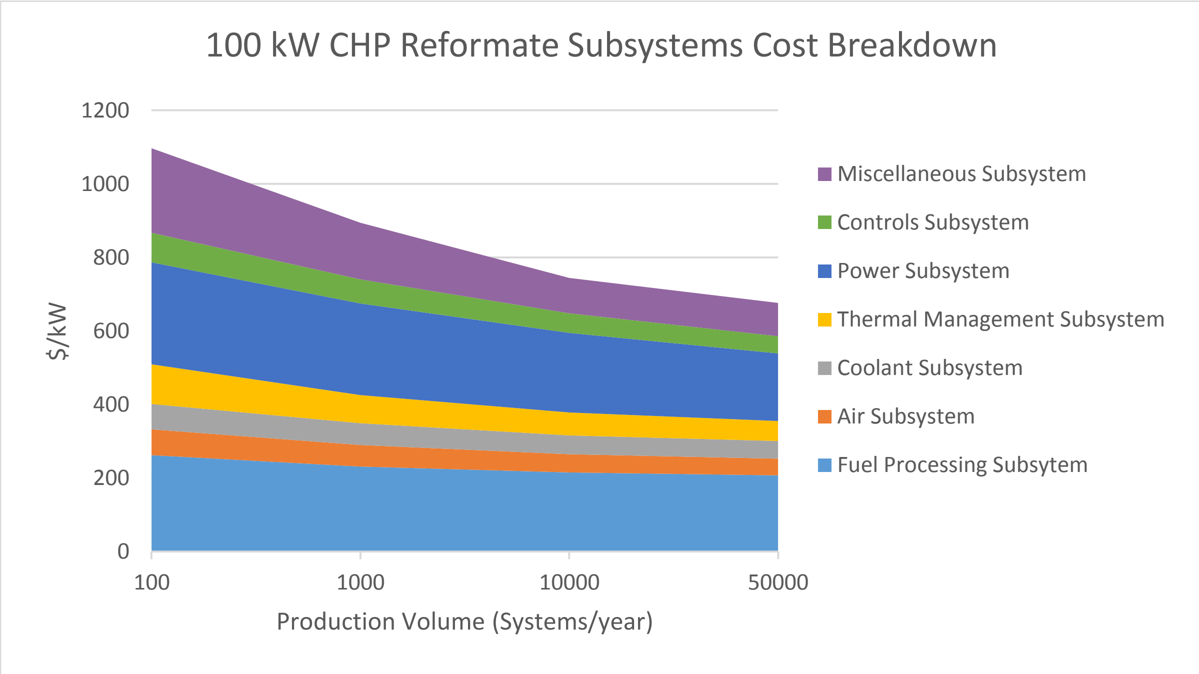


Figure 5-2 Subsystem cost breakdown of 100 kW CHP system with reformate fuel

The fuel processing subsystem is the largest component of system cost at 10 kW, making up 27% of the overall BOP cost at 100 systems/year and 31% at 50,000 systems/year. At 100 kW system power subsystem and fuel processing subsystem are the most important components, comprising about 60% of total BOP costs for 50,000 systems/year.

Figure 5-3 displays the BOP cost as a function of manufacturing volume for the CHP system with reformate fuels.

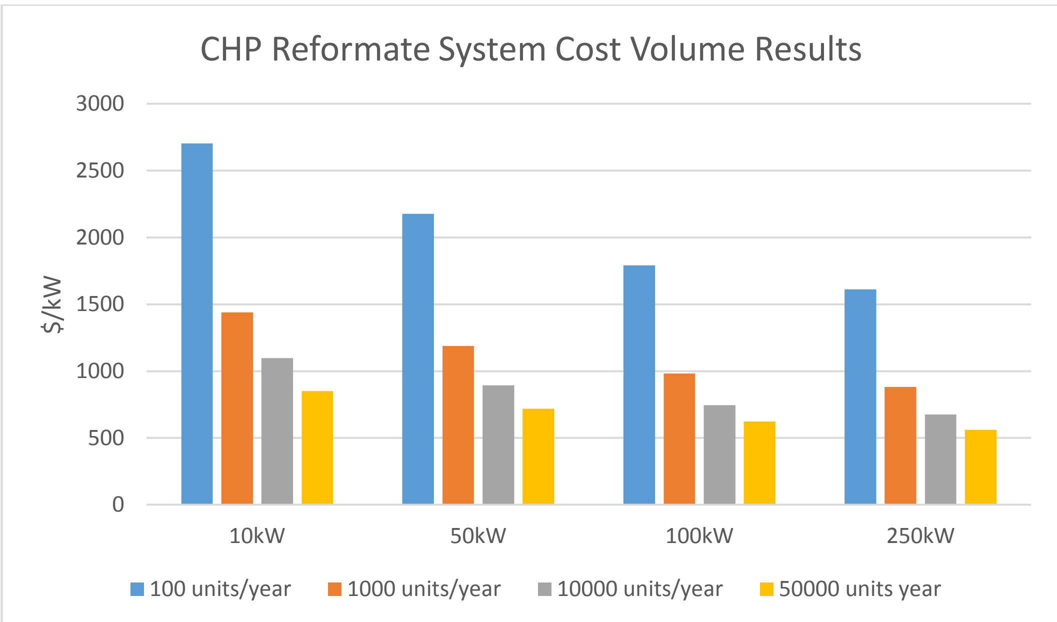


Figure 5-3 BOP cost volume results for CHP system with reformate fuel

The cost per unit of electric output decreases with increasing manufacturing volume and increasing system size. Increasing capacity appears to have a greater effect on cost reduction in comparison to increasing manufacturing volume.

Table 5-2 summarizes the volume cost results for the CHP system with reformate fuel. The data show that cost reduction is seen to be generally less than 20% per ten-fold increase in annual volume. Vendor quotes were utilized for BOP component as a function of volume and were often less than 20% per decade increase in annual volume.

Compared to the 2014 LBNL report the BOP costs are very similar at high power sizes but increase by about 15% for the 10 kW CHP system and about 40% for the 1 kW CHP system. These are driven by higher costs for heat exchangers and the addition of a condenser in the thermal management system, and the addition of labor costs in the miscellaneous category. A boiler and tank was added to the 1 kW micro-CHP system only. Note that the stack cost reductions in the previous chapter (e.g. Figure 4-48) are offset by increases in the estimate balance of plant costs, so that overall system costs are within 10% of the 2014 LBNL report for system sizes greater than 1 kW.

Table 5-2 Summary of BOP cost for CHP system with reformate fuel ($/kW)

System Size	Units per Year			
	100	1,000	10,000	50,000
1 kW	16,788	13,362	11,208	9,861
10 kW	2,703	2,177	1,792	1,612
50 kW	1,439	1,188	982	881
100 kW	1,097	894	744	676
250 kW	852	719	622	562

Table 5-3 Summary of BOP percent cost changes in for CHP systems compared to LBNL 2014

System Size	Units per Year			
	100	1,000	10,000	50,000
1 kW	41%	41%	39%	38%
10 kW	20%	16%	13%	14%
50 kW	10%	6%	2%	3%
100 kW	10%	5%	1%	2%
250 kW	3%	-1%	-3%	-2%

5.2 Fuel cell system direct manufacturing costs and installed cost results

Stack costing from Chapter 4 and balance of plant costing from Chapter 5 are integrated in this chapter to provide a roll up of fuel cell stack direct manufacturing costs, system costs including stack costs and balance of plant/fuel processor costs, and installed costs for CHP systems with reformate fuel. Figure 5-4 and 5-5 show the overall system costs per kW as function of production volume (100, 1,000, 10,000, and 50,000 systems per year).

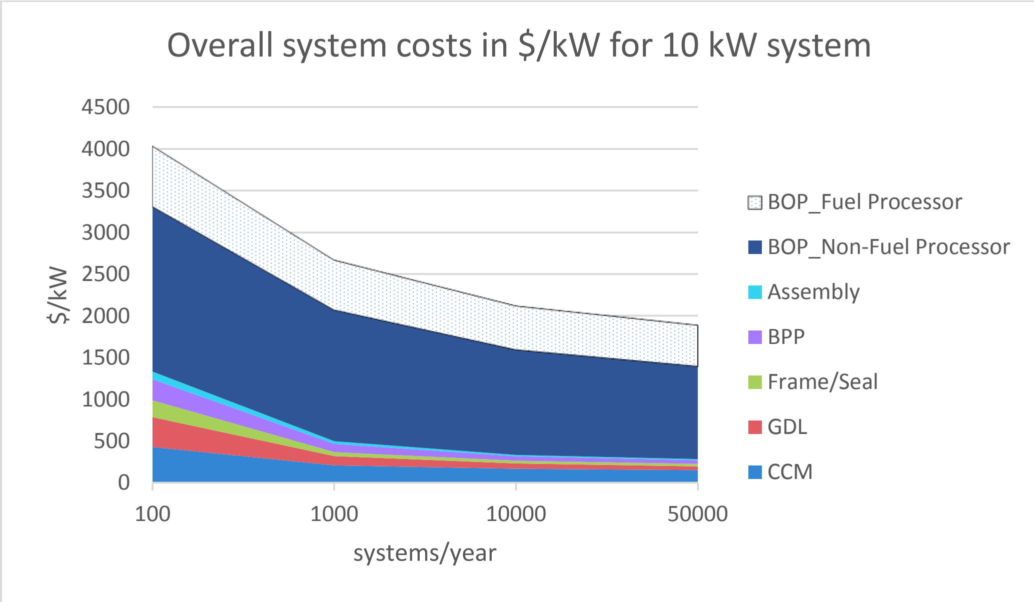


Figure 5-4 Overall system cost results for CHP systems with reformate fuel for 10 kW systems

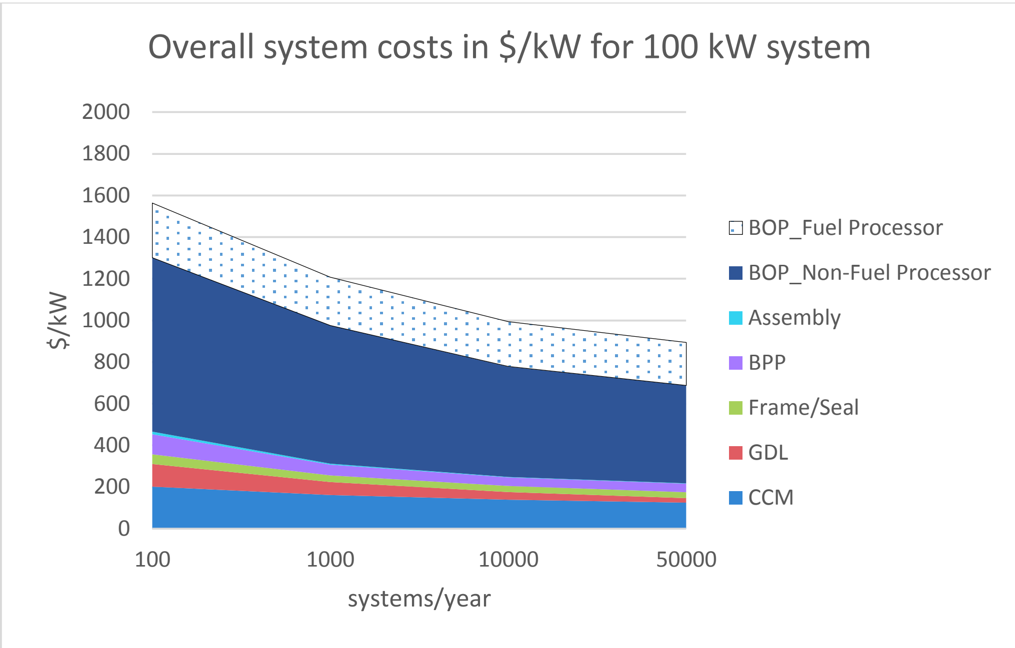


Figure 5-5 Overall system cost results for CHP systems with reformate fuel for 100 kW systems

Figure 5-6 and 5-7 show a breakout of BOP costs versus FC stack costs as a percentage of overall costs. For 10 kW and 100 kW CHP systems, for all the production volumes, BOP costs are greater than stack costs with the largest component from balance of plant non-fuel processor costs.

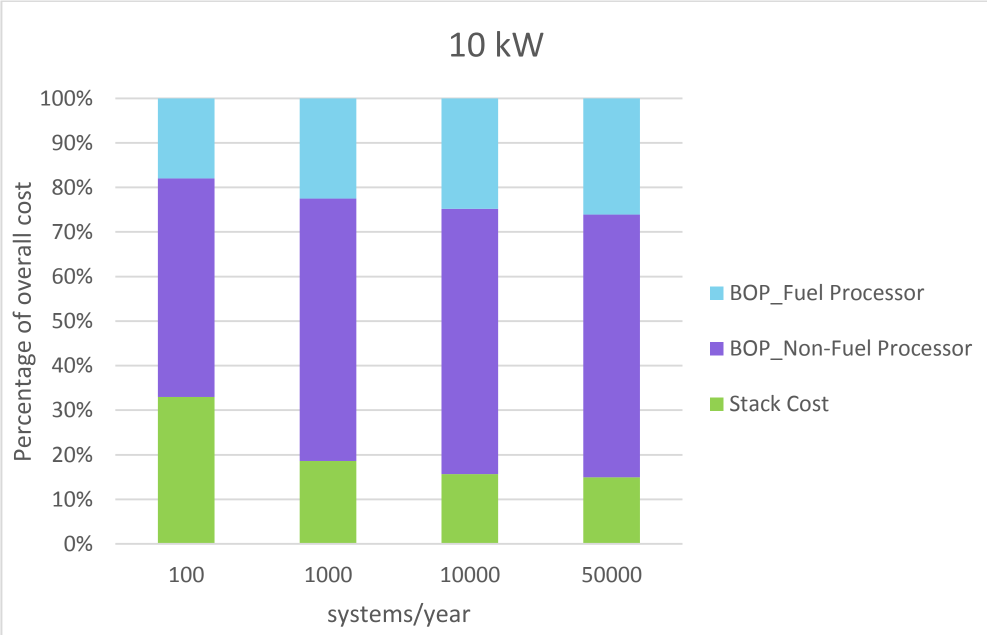


Figure 5-6 Percentage of overall system costs for BOP and fuel stack for 10 kW CHP systems

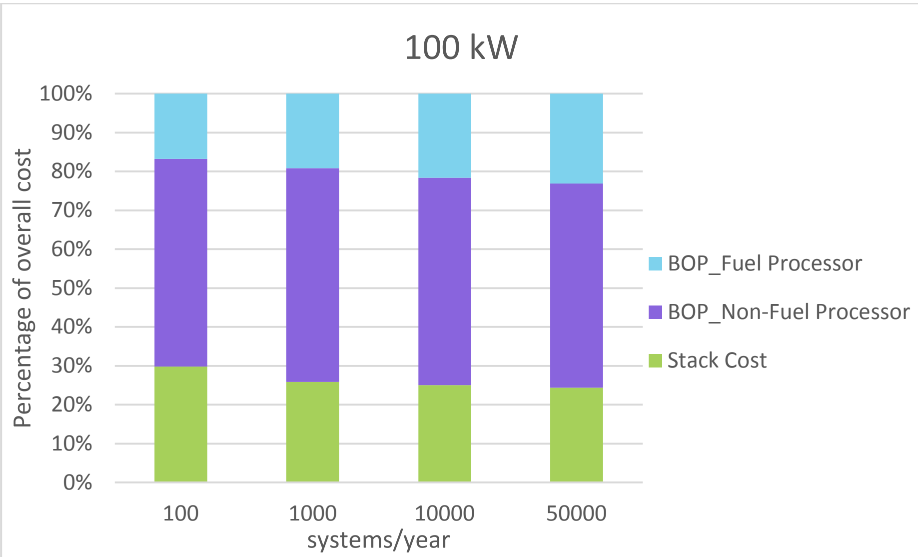


Figure 5-7 Percentage of overall system costs for BOP and fuel stack for 100 kW CHP systems

5.3 CHP target costs

Customer costs for 10 kW and 100 kW CHP systems, based on the direct manufacturing costs, are compared to DOE targets for 2015 and 2020. Figure 5-8 and Figure 5-9 illustrate respectively the installed cost for 100 kW CHP system for 1,000 systems per year and 50,000 systems per year. A markup of 50% is considered to determine the equipment costs. From Figure 5-9 the 2020 target can nearly be met at 100 kW and 50,000 systems per year, but is missing the target at 1,000 systems per year.

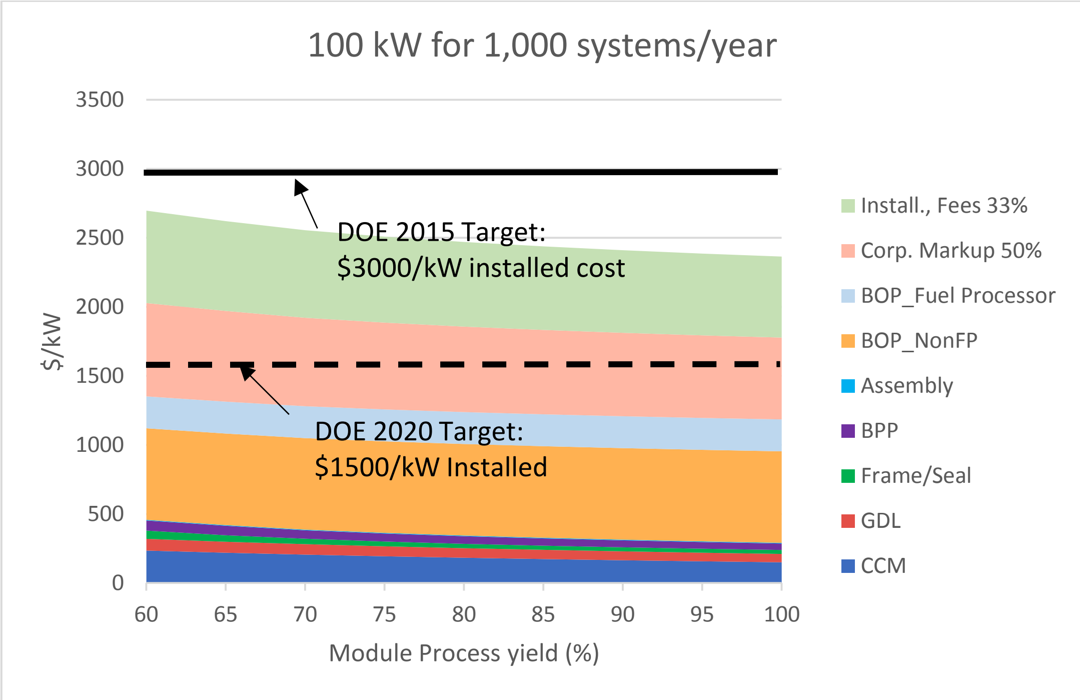


Figure 5-8 Installed cost for 100 kW CHP system, 1,000 systems per year

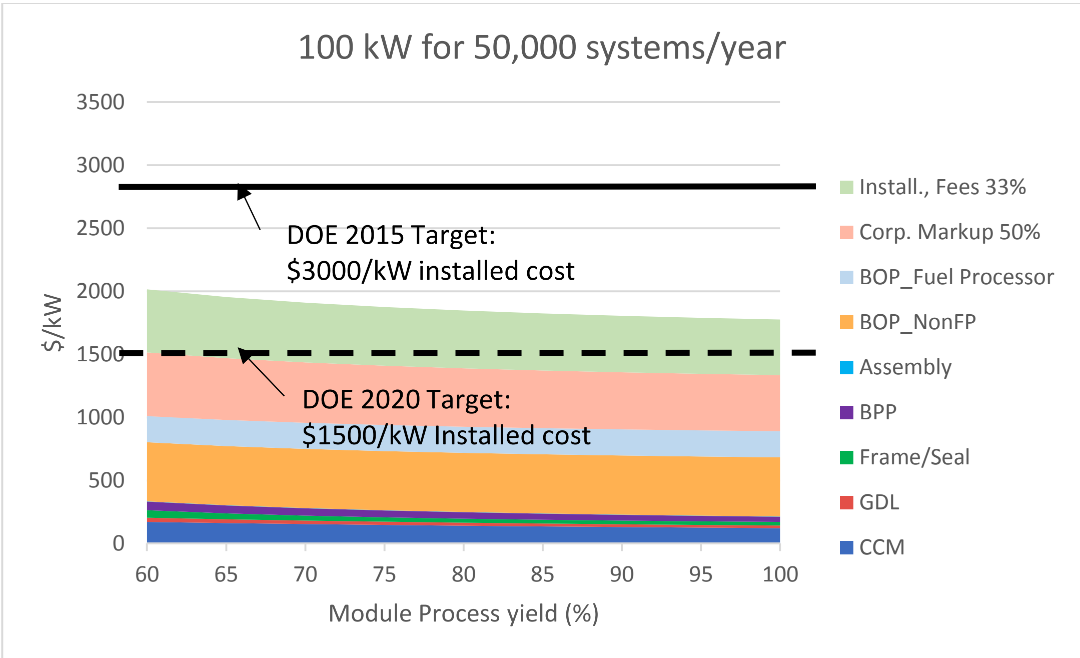


Figure 5-9 Installed cost for 100 kW CHP system, 50,000 systems per year

Tables 5-4 and 5-5 summarize the total direct system cost and total installed system cost for PEM FC CHP systems which combine the data from Tables 4-35 and 5-2 above. For the installed cost, a 50% markup corporate is included and a 33% markup for installation costs and any additional fees. At high manufacturing volumes, a 10kW (100kW) CHP system has estimated direct manufacturing costs of about $1900 ($900)/kW and an installed price of about $3800 ($1800)/kW.

Table 5-4 Summary of total direct system costs for PEM FC CHP system with reformate fuel ($/kW)

System Size	Units per Year			
	100	1,000	10,000	50,000
1 kW	26,098	14,937	11,879	10,314
10 kW	4,043	2,674	2,125	1,896
50 kW	2,035	1,540	1,254	1,120
100 kW	1,563	1,207	993	895
250 kW	1,229	998	853	765

Table 5-5 Summary of total installed system cost for PEM FC CHP system with reformate fuel ($/kW)

System Size	Units per Year			
	100	1,000	10,000	50,000
1 kW	52,065	29,799	23,698	20,577
10 kW	8,067	5,335	4,240	3,782
50 kW	4,060	3,073	2,502	2,235
100 kW	3,118	2,408	1,981	1,785
250 kW	2,451	1,991	1,701	1,526

As can be evinced from this work, the BOP can actually be the dominant cost driver in FCS. With increased manufacturing volume of fuel cell systems, there will be greater potential for fuel cell companies to standardize an increasing number of BOP parts for specific fuel cell systems. Commoditization of BOP components for FCS may in turn significantly impact system cost with the emergence of more fuel cell systems in the market.

6 DFMA Manufacturing Cost Analysis for Backup Power Application

6.1 Introduction

Hydrogen can be used to power nearly every end-use energy need. Dedicated fuel cell backup power systems are at the early commercial stage with several vendors supplying low temperature PEM units in the 200 W to 50 kW range, with the most prevalent being 5 kW.

Various applications exist, the most common and fastest growing being the use for cellular telecommunications sites. The telecommunications industry is the largest user, driven largely by the rapidly expanding wireless communication network in developing countries, and the need for a resilient grid in developed countries [17].

Telecom companies are increasingly choosing fuel cell systems to lower their environmental impact, improve network reliability, and reduce operating expenses through the use of more efficient equipment. Telecommunications backup power expenditures are estimated at more than $2 billion annually [18].

There are different industry drivers for this technology:

- Increased network reliability requirements
- Loss of power from the grid (weak utility infrastructures, severe weather and security concerns) require extended backup power runtimes
- Expansion into regions without electric grids
- Government initiatives and sustainability programs

The target environment for backup power systems are those sites that are susceptible to severe weather, natural disasters, and poor electric grid reliability or those areas with a local (cost effective) source of fuel (hydrogen or liquid fuel). Numerous applications have been identified and are under development including telecommunications (wireless networks, 911 operators, evacuation centers), railroad signaling (crossings, wayside signals), and government and military applications.

Fuel cell backup power can provide a critical service in times of emergencies and decrease the economic and productivity losses during other grid instabilities when compared with incumbent technologies. Fuel cells can provide an extended run time similar to that of diesel generators while also providing a low-emission and low-noise solution, which is especially important in urban environments.

6.1.1 Advantages of FC backup power

FC backup power systems have several advantages over conventional systems, such as diesel and batteries, include:

- *Improved durability and reliability:* 15 years lifetime compared to batteries, which have approximately 5 years lifetime.
    - Ability to operate over large ambient temperature ranges (-50° to +50°C).
    - Reliable startup: in a sample of 852 fuel cell systems studied in the United States, systems started reliably 99.5% of 2578 startup attempts [19]. In contrast diesel

generators require more maintenance and are susceptible to mechanical failure due to the higher number of moving parts.

- *Scalability*: power run time is directly scaled to fuel available, units are modular, and efficiency is independent of power level, allowing scaling to any power need.
- *Environmental benefits:* low to zero emissions; quiet operation.
- *Fuel flexibility:* various fuels can be used, including renewable fuels, linked to solar or wind for example.
- *Reduced weight and volume*: A methanol/water reformer/PEM FC system with an auxiliary battery, and 4-5 kW power output, was one quarter of the volume and one fourteenth of the weight of a conventional lead storage battery for 24h of backup coverage [20].
- *Economical:* While current installation costs may be higher compared to incumbent solutions, the systems are durable and require minimal annual maintenance visits leading to reduce cost of ownership.

Over a 6-year period or longer, a fuel cell powered backup system is cheaper than a battery-operated one. Figure 6-1 shows a schematic cost comparison between a battery and a fuel cell over six years.

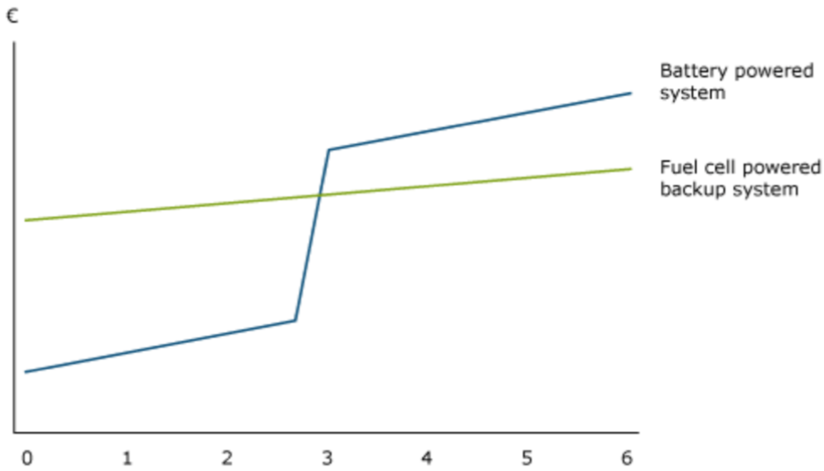


Figure 6-1 Cost comparison between a battery and a fuel cell [21]

A battery powered system (blue line) starts off cheaper than a fuel cell powered backup system (green line). However, over time, the total costs for a battery operated system are higher. Although the regular maintenance required greatly varies depending on the battery type, even low maintenance batteries, as plotted in the graph above, have higher maintenance costs than fuel cell systems.

The big jump in costs for batteries after 3 to 5 years (depending on the operating profile) is due to battery replacement, while the fuel cells have a longer lifetime. Taking these replacement costs into account, it becomes clear that the fuel cell system can provide a more economic option.

6.1.2 Fuel cell backup power system design

The fuel cell backup power plant consists of three major components:

- Hydrogen Storage
- Fuel Cell Stack
- Battery/Capacitor

Hydrogen Storage

Fuel cell installations are typically fueled by a six-pack of compressed hydrogen storage containers. These containers each hold either 139 scf (standard cubic foot) or 261 scf of hydrogen at a pressure of 2,400 psi and a weight of 137 lbs. They have the combined capacity to power a fuel cell for 24–96 hours [22]

Fuel Cell Stack

A single fuel cell will not provide the required power for most applications. Therefore, multiple fuel cells, referred to as a stack, are linked together in a fuel cell power plant to meet the required power demand.

Battery/Capacitor

Fuel cell power plants used for backup power typically require a DC storage device to provide immediate power while the fuel cell powers up. PEM fuel cells power up quickly, but there is still a short period of time that requires the use of a battery or capacitor to supply power.

Telecommunications installations with backup fuel cell power often incorporate fuel cells and batteries. As the system voltage changes, rectifiers or controllers switch between the primary power source and the backup power sources.

In the absence of grid power or another primary alternating current (AC) power source, the fuel cells, or a combination of fuel cells and batteries, provide direct current (DC) power to run the equipment. The fuel cells have internal batteries that provide temporary "bridge" power until the fuel cell reaches peak power production and takes over the load. When the primary power source is restored, the fuel cells shut down, and the load is returned to the primary source.

Figure 6-2 shows a fuel cell backup power system design.

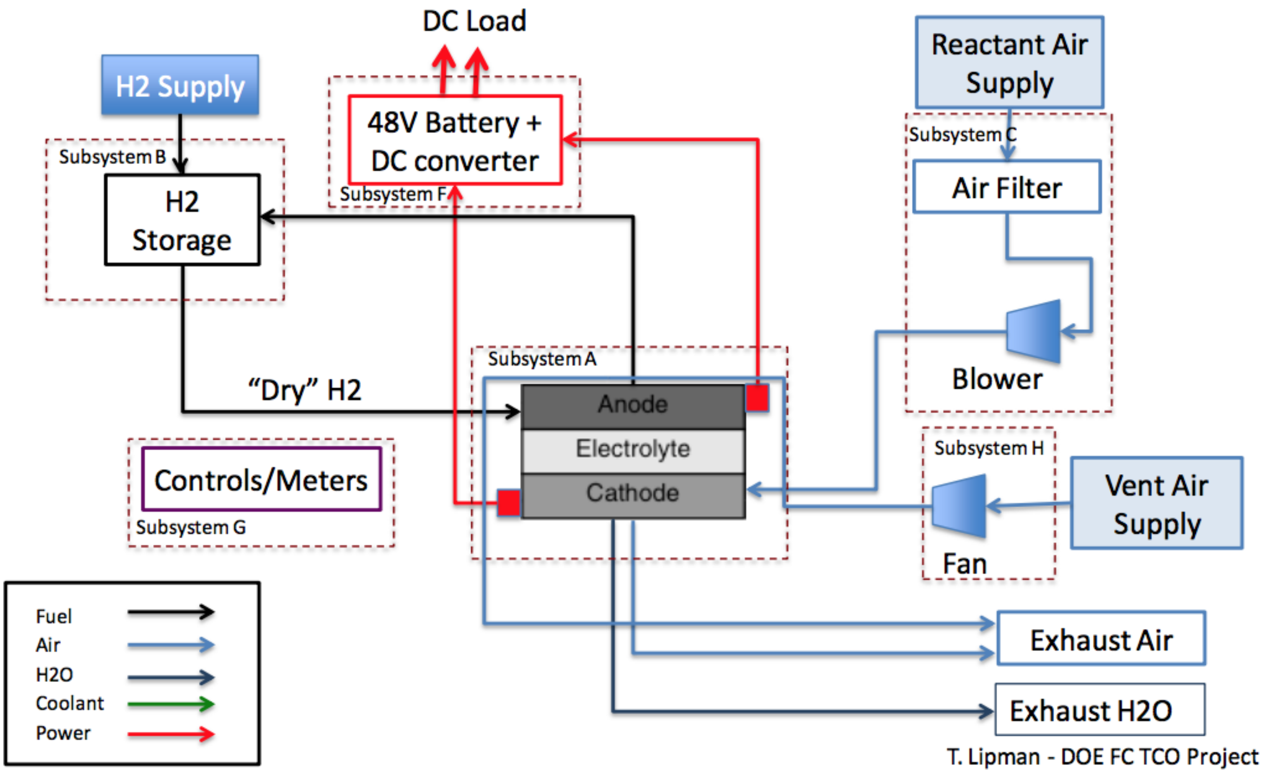


Figure 6-2 Backup power system design

Compared to CHP, backup power system design achieves cost reduction through simplification of balance of plant components with air-cooled system design and once-through H_2 fuel supply. Since the load for backup power is assumed to be DC power, there is a DC to DC power converter instead of a DC to AC inverter.

6.2 Catalyst coated membrane (CCM)

The CCM backup power cost model is analyzed starting from the CHP model and modifying the functional specifications and Pt loading for the catalyst. Fuel cell sizes taken into account are 1 kW, 10 kW and 50 kW. Table 6-1 and Table 6-2 summarize these changes.

Table 6-1 CHP and Backup PEM FC general parameters comparison

PEMFC Application	CHP	Backup
Single cell active area (cm^2)	220	285
Pt total loading (mg/cm^2)	0.5	0.3

Table 6-2 CHP and backup PEM FC functional specifications comparison

PEMFC size	1 kW CHP	1 kW Backup	10 kW CHP	10kW Backup	50 kW CHP	50 kW Backup
current density (A/cm^2)	0.49	0.4	0.5	0.41	0.5	0.42
power density (W/cm^2)	0.346	0.261	0.353	0.269	0.352	0.272
cells per stack	17	14	164	136	136	96
stacks per system	1	1	1	1	6	7

Tables 6-3, 6-4 and 6-5 show CCM final costs in terms of $/kW.

Table 6-3 CCM cost results for 1 kW

System size (kW)	1 kW			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	235.14	191.77	159.83	142.84
Direct Labor ($/kW)	237.50	23.75	3.45	2.26
Process: Capital ($/kW)	1443.70	144.37	14.44	4.68
Process: Operational ($/kW)	132.38	13.74	1.59	0.69
Process: Building ($/kW)	126.22	12.62	1.26	0.31
Material Scrap ($/kW)	307.08	31.55	5.52	2.62
Final Cost ($/kW)	2482.03	417.80	186.09	153.40

Table 6-4 CCM cost results for 10 kW system

System size (kW)	10 kW			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	186.66	155.55	132.96	118.30
Direct Labor ($/kW)	23.75	3.34	2.20	2.17
Process: Capital ($/kW)	144.37	14.44	2.34	0.94
Process: Operational ($/kW)	13.73	1.58	0.47	0.34
Process: Building ($/kW)	12.62	1.26	0.15	0.07
Material Scrap ($/kW)	31.35	5.43	1.88	0.59
Final Cost ($/kW)	412.48	181.60	140.00	122.41

Table 6-5 CCM cost results for 50 kW system

System size (kW)	50 kW			
Production volume (units/year)	100	1,000	10,000	50,000
Direct Materials ($/kW)	162.49	137.48	117.00	103.34
Direct Labor ($/kW)	3.36	2.17	2.15	1.42
Process: Capital ($/kW)	28.87	4.68	0.94	0.94
Process: Operational ($/kW)	2.90	0.68	0.34	0.22
Process: Building ($/kW)	2.52	0.31	0.07	0.09
Material Scrap ($/kW)	8.44	2.56	0.59	-0.29
Final Cost ($/kW)	208.58	147.89	121.08	105.72

6.3 Metal bipolar plates

Since stack lifetimes are less stringent in backup applications than stationary applications, metal plates, instead of carbon plates, are considered in this cost analysis. Stationary stack lifetime can achieve up to 60,000 h, backup stack lifetime up to 5,000 h.

Metal plates have several potential advantages over carbon plates:

- higher yield and less cracking;
- potential to be thinner and lighter;
- higher electrical and thermal conductivity;
- potentially more re-usable at stack end-of-life.

Stainless steel bipolar plates (BPPs) are regarded as promising alternatives to traditional graphite BPPs in proton exchange membrane fuel cells (PEM FCs) [23].

However, a key requirement is the need for a robust coating over the metal to ensure that the plates that can withstand the corrosive environment of the fuel cell stack operating conditions. The above finding is confirmed by a published report (Ma et al.), that studied the corrosion behavior of 316L SS bipolar plates and concluded that such plates must be coated since they can corrode in both anode and cathode environments.

In this regard, the deposition process is based on a patent [24] which indicates as 0.1 mm of stainless steel 316L and 4 um of Chromium nitride can be reach the goals set by the DOE. This coating presents an interfacial contact resistance (ICR) of 8.4 mΩ cm^{-2} under 1.4 MPa.

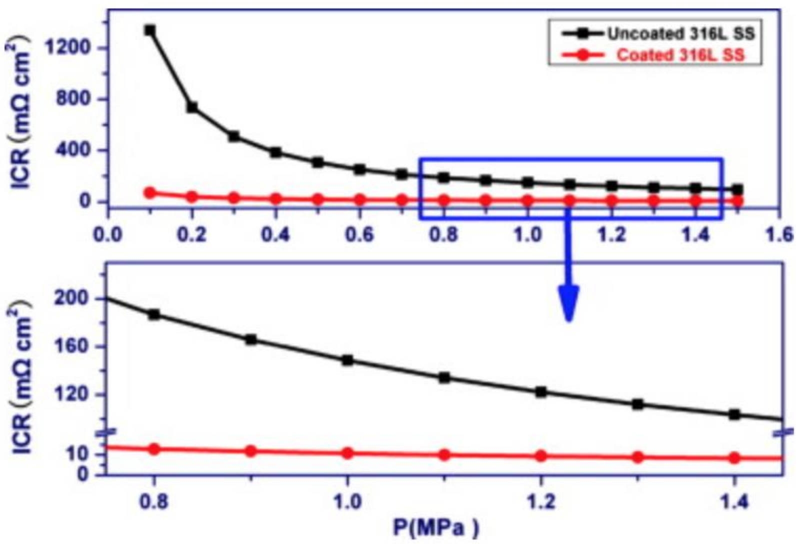


Figure 6-3 Interfacial coating resistance from patent [24]

The bipolar plate is considered to be one of the most costly and problematic of the fuel cell stack [25]. The following plot, from LBNL 2014, shows the percentage of overall fuel cell stack costs for 10kW backup power application.

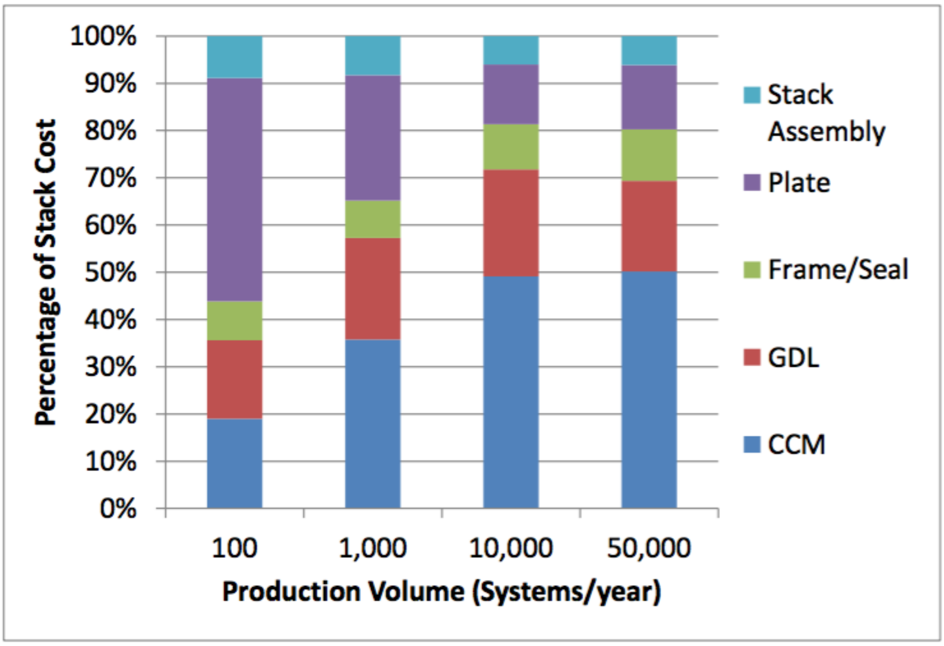


Figure 6-4 Relative percentage of costs for 10 kW backup power stack.

As can be noted, metal plates are one of the principal cost component, especially at low production volume where covers almost the 50% of total cost. For these reasons, we decided to revise the bipolar plates cost model, considering innovative alternative processes to reduce the cost of BPP. 316L stainless steel is also chosen to be consistent with alternative processes that will be considered in next chapters.

6.3.1 Process flow description

The process flow (Figure 6.5) consists of the following modules: stamping of a sheet roll of stainless steel, cleaning and drying, laser welding to seal the plates, cleaning and drying, physical vapor deposition (PVD) of the coating, and a final inspection.

The bottleneck time of these configurations is the physical vapor deposition step derived from a loading and unloading time per piece of 2 seconds using robots and 4 seconds in the manual loading case:

$$bottleneck\ time\ (s) = \frac{PVD\ cycle\ time\ (s) + batch\ size\ \left(\frac{pieces}{cycle}\right) * \frac{load + unload\ time\ (s)}{piece}}{batch\ size\ (\frac{pieces}{cycle})}$$

In contrast to LBNL 2014 work, three configurations, according to the annual volume, are analyzed: manual, semi-automatic, and automatic (Table 6-6) [14].

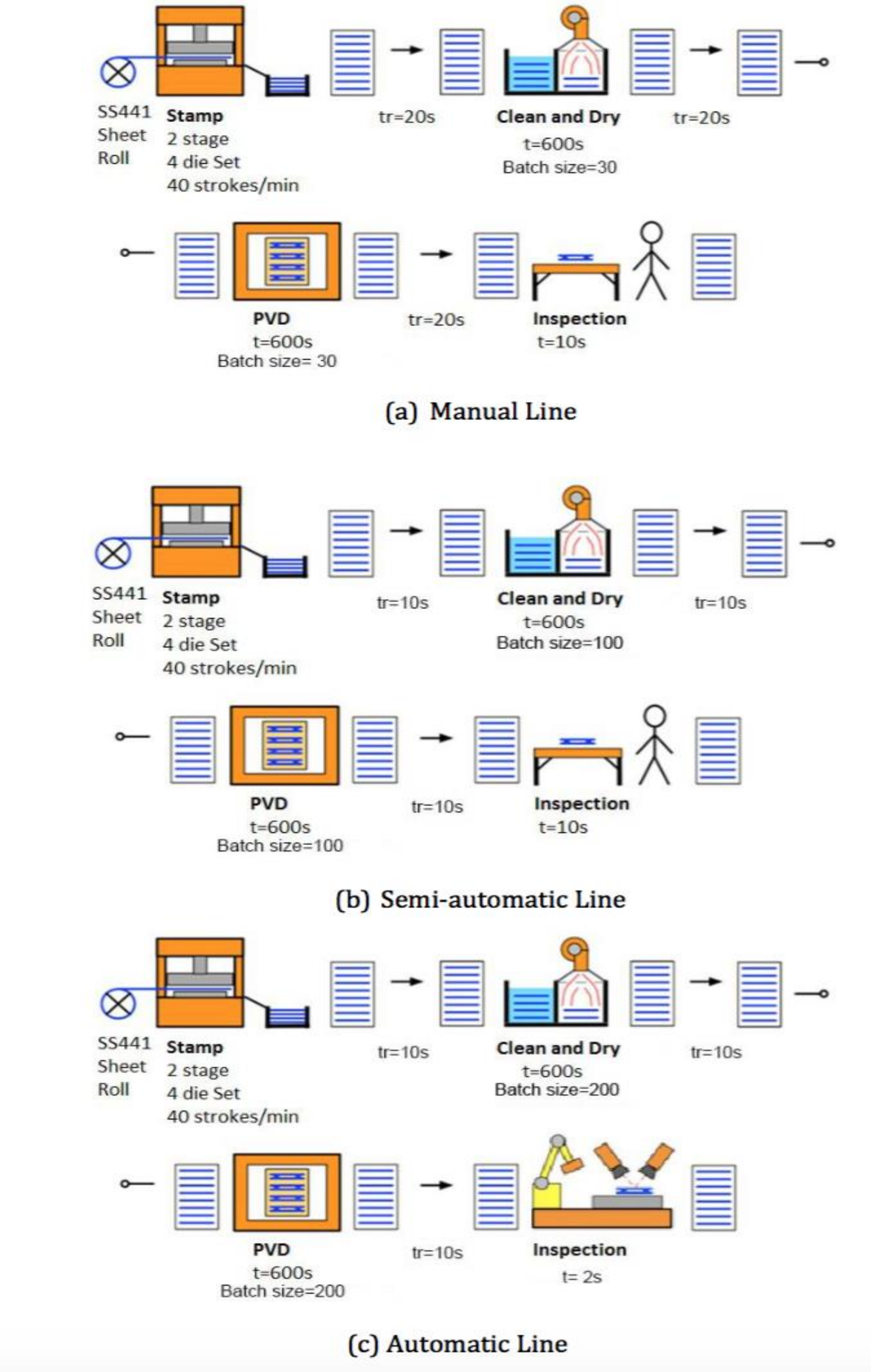


Figure 6-5 Metal bipolar plates process line

Table 6-6 Metal bipolar plates line configurations

	MANUAL (< 25 MW)		SEMI (from 25 MW to 250 MW)		AUTO (> 250 MW)	
Equipment	Cost ($)	Power (kW)	Cost ($)	Power (kW)	Cost ($)	Power (kW)
Dual Die Stamper	50,000	7.5	480,000	17	480,000	17
Pick-place robot	0	0	165,000	2	165,000	2
Cleaner/Dryer	200,000	5	500,000	10	750,000	10
Pick-place robot	0	0	165,000	2	165,000	2
PVD	500,000	140	1,920,000	504	2,875,000	756
Pick-place robot	0	0	165,000	2	165,000	2
Auto Welder	1,125,000	31	1,125,000	31	1,125,000	31
Pick-place robot	0	0	0	0	165,000	2
Auto Inspection	0	0	0	0	250,000	10
Total	1,875,000	184	4,520,000	568	6,140,000	832
Bottle Neck Time (s)	28		10		7	

6.3.2 Metal plates properties

Bipolar plate properties taken into account are:

- Area of 360 cm^2, 36 cm x 10 cm
- 6 manifolds, each manifold 3 cm x 2.5 cm
- 27 channels with land and channel width at 1.5 mm
- sheet metal thickness: 0.1 mm
- coating thickness 0.4 um
- Total BPP mass: 51.1 g

Table 6-7 Metal bipolar plates bill of materials

Metal bipolar plates			
Component	Material	Cost ($/kg)	Reference
sheet metal	SS 316L	4	[26]
coating powder	CrN	50	[1]

Table 6-8 provides a summary of cost model changes compared to LBNL 2014 report.

Table 6-8 BPP cost model changes

Parameter	LBNL 2014	This work
Plate size (cm^2)	362.5	360
Operational days	250	240
Discount rate	0.15	0.1
Inflation rate	0.026	0.017
Energy Inflation rate	0.056	0.05
Labor rate	28.08	29.81
Inflation rate	0.017	0.0165
Property tax rate	0.014	0.0104
Maintanance	0.15	0.1
Stainless Steel	304	316L
Stainless Steel price ($/kg)	11	4
CrN thickness (cm)	0.0002	0.0004

Process yield, setup time, line availability are all functions of interconnect annual production volume while line performance is assumed to be at 89% for manual configuration and 95% for semi-automatic and automatic configurations.

At low volumes (< 100,000 interconnects/year) setup time is assumed to be 60 minutes, line availability to be 80% and process yield to be 85%. At high volumes (> 10,000,000 interconnects/year), setup time is estimated to be 5 minutes, line availability to be 95%, and process yield to be 99.5%. For volumes between 100,000 and 10,000,000 interconnects/year, the process parameters are found through exponential interpolation.

Table 6-9 illustrates a process parameters comparison between this work and the LBNL 2014 cost study, where configuration A (Batch size of 50 BPP), configuration B (Batch size of 100 BPP).

Table 6-9 BPP process parameters comparison

Fuel Cell Size (kW)	1	1	1	1	10	10	10	10	50	50	50	50
Annual Quantity	100	1.000	10.000	50.000	100	1.000	10.000	50.000	100	1.000	10.000	50.000
Cells/Stack LBNL 2014	15	15	15	15	150	150	150	150	124	124	124	124
Cells/Stack This Work	14	14	14	14	136	136	136	136	96	96	96	96
stack/system LBNL 2014	1	1	1	1	1	1	1	1	6	6	6	6
stack/system This Work	1	1	1	1	1	1	1	1	7	7	7	7
# line LBNL 2014	1	1	1	1	1	1	1	4	1	1	4	20
# line This Work	1	1	1	1	1	1	1	4	1	1	4	19
cycle time LBNL 2014	12,4	12,4	12,4	7,1	12,4	12,4	7,1	7,1	12,4	7,1	7,1	7,1
cycle time This Work	28	28	28	10	28	28	10	7	28	10	7	7
setup time LBNL 2014	60	60	34,4	14,4	60	33,3	9,6	5	48,6	14	5	5
setup time This Work	60	60	52,1	21,9	60	52,1	15	6,3	60	21,9	6,3	5
process yield LBNL 2014	85,00%	85,00%	88,05%	93,03%	85,00%	88,23%	95,46%	99,50%	86,14%	93,20%	99,50%	99,50%
process yield This Work	85,00%	85,00%	85,80%	90,60%	85,00%	85,80%	92,80%	98,00%	85,00%	90,60%	98,00%	99,50%
line availability LBNL 2014	80,00%	80,00%	83,13%	88,28%	80,00%	83,33%	90,80%	95,00%	81,17%	88,45%	95,00%	95,00%
line availability This Work	80,00%	80,00%	80,80%	85,80%	80,00%	80,80%	88,00%	93,50%	80,00%	85,80%	93,50%	95,00%
line performance LBNL 2014												
line performance This Work	89,00%	89,00%	89,00%	95,00%	89,00%	89,00%	95,00%	95,00%	89,00%	95,00%	95,00%	95,00%
workers/line LBNL 2014	3	3	3	3	3	3	3	1,25	3	3	1,25	1,05
workers/line This Work	4	4	4	2	4	4	2	1	4	2	1	1
Line configuration LBNL 2014	A	A	A	B	A	A	B	B	A	B	B	B
Line configuration This Work	manual	manual	manual	semi	manual	manual	auto	auto	manual	semi	auto	auto

Table 6-10 shows 50 kW metal plates cost analysis.

Table 6-10 Metal plates cost analysis

Metal plates				
System size (kW)	50			
Production volume (units/year)	100	1,000	10,000	50,000
Cells/Stack	96	96	96	96
Line configuration	manual	semi	auto	auto
setup time	60.00	21.85	6.31	5.00
workers/line	4.0	2.0	1.0	1.0
max # of bip/line/year	329554.3	1101147.9	1742636.9	1773025.7
# of lines	1	1	4	19
line utilization	23.74%	66.66%	97.35%	99.20%
annual operating hours	684	2146	13889	68398
labor cost	86620	130868	416749	2049550
Cycle Time (s)	28	10	7	7
Process Yield	85.00%	90.60%	98.00%	99.50%
Half Plates/yr	133000	1330000	13300000	66500000
BPP/yr	66500	665000	6650000	33250000
Cells/yr	67200	672000	6720000	33600000
Power Consumption	183.5	568	832	832
Machine Footprint (m2)	70	263	353	353
Initial Capital ($)	1875000	4520000	24560000	116660000
Initial System Cost ($)	2625000	6328000	34384000	163324000
Annual Depreciation ($/yr)	122500.00	295306.67	1604586.67	7621787
Annual Cap Payment ($/yr)	310705.19	749006.64	4069823.71	19331663
Maintenance ($/yr)	22193.23	53500.47	290701.69	1380833
Salvage Value ($/yr)	679.11	1637.11	8895.45	42253
Energy Costs ($/yr)	15664.78	152207.35	1442815.38	7105321.99
Property Tax ($/yr)	7800.00	18803.20	102169.60	485306
Building Costs ($/yr)	5069.76	19047.80	102264.24	485755.15
Machine Cost ($/yr)	360753.8	990928.4	5998879.2	28746625
Labor Cost	86620	130868	416749	2049550
316L (kg)	4450	41750	385971	1900764
CrN (kg)	119	1114	10299	50719
material cost	23025	216020	1997085	9834889
Scrap/Recycle	10%	10%	10%	10%
TOTAL COST	470399	1337816	8412713	40631064
$/kW	94.1	26.8	16.8	16.3
$/PLATE	7.07	2.01	1.27	1.22

We assume that stainless steel waste is recyclable and sold at a price equal to 40% of the primary material purchase price [14].

6.3.3 Metal plates cost summary

Tables 6-11, 6-12 and 6-13 summarize metal plate costs for 1 kW, 10 kW and 50 kW systems.

Table 6-11 Metal plate cost summary for 1 kW system

System size (kW)	1 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	239.00	23.90	2.39	1.15
Direct Labor $/plate	18.27	1.83	1.28	0.20
Direct Materials $/plate	0.36	0.36	0.35	0.33
Process: Operational $/plate	17.31	1.94	0.40	0.31
Process: Building $/plate	9.38	0.94	0.09	0.06
Material Scrap $/plate	-0.01	-0.01	-0.01	-0.01
Final Cost $/plate	284.30	28.95	4.51	2.04

Table 6-12 Metal plate cost summary for 10 kW systemSystem size (kW)	10 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	23.02	2.30	0.75	0.60
Direct Labor $/plate	1.76	1.28	0.07	0.06
Direct Materials $/plate	0.36	0.35	0.33	0.31
Process: Operational $/plate	1.88	0.40	0.28	0.26
Process: Building $/plate	0.90	0.09	0.04	0.03
Material Scrap $/plate	-0.01	-0.01	-0.01	-0.01
Final Cost $/plate	27.90	4.41	1.46	1.25

Table 6-13 Metal plate cost summary for 50 kW systemSystem size (kW)	50 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	4.67	1.13	0.61	0.58
Direct Labor $/plate	1.30	0.20	0.06	0.06
Direct Materials $/plate	0.36	0.33	0.31	0.30
Process: Operational $/plate	0.57	0.31	0.26	0.26
Process: Building $/plate	0.18	0.05	0.03	0.03
Material Scrap $/plate	-0.01	-0.01	-0.01	-0.01
Final Cost $/plate	7.07	2.01	1.27	1.22

These tables show the relationship between production volume and cost. As the annual production of bipolar plates increases, the bipolar plate cost decreases. At the highest volumes, the cost per plate converges to $1.22/plate.

Figures 6-6 and 6-7 show the fractions of bipolar plate costs as a function of annual production volume for 10 kW and 50 kW system sizes.

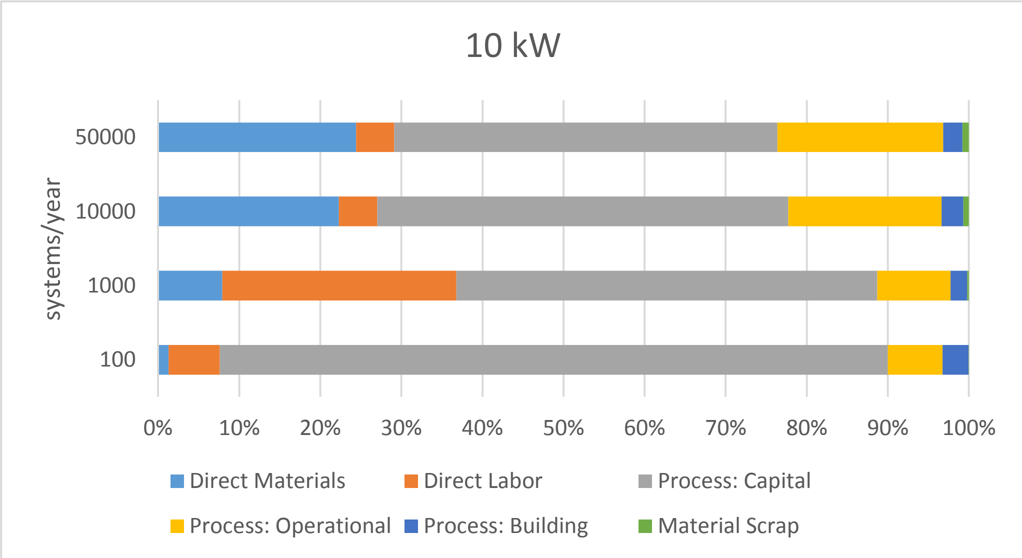


Figure 6-6 Percentage cost breakdown for metal bipolar plate, for 10 kW system

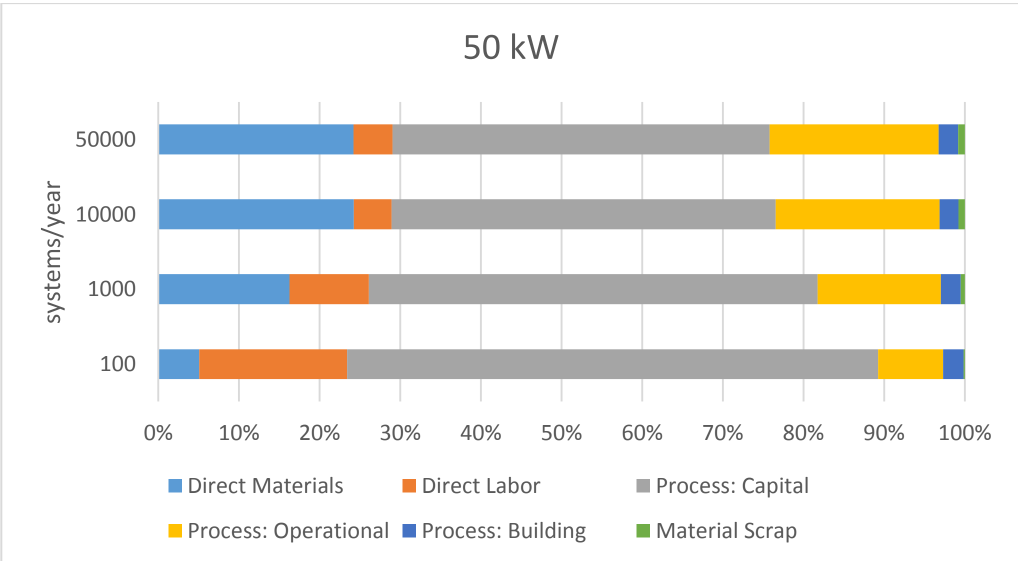


Figure 6-7 Percentage cost breakdown for metal bipolar plate, for 50 kW system

Capital cost is the principal cost component for all configurations. Material costs make up 30% of the total plate cost at volumes above 100 MW. Direct labor reduction at high volume is due to fewer workers/line in moving from a manual to a semi/automatic configuration. Table 6-14 shows $/plate and $/kW results, over annual volume (kW).

Table 6-14 Metal plates cost comparison in terms of $/plate and $/kW

Metal bipolar plate								
Annual Volume (kW)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
This work $/plate	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
LBNL 2014 $/plate	861.36	88.17	18.50	10.71	3.83	2.57	2.08	2.07
This work $/kW	3.696	376.4	94.1	58.6	26.5	19.7	16.9	16.3
LBNL 2014 $/kW	12,059.1	1,234.3	273.1	150.0	53.6	38.4	31.0	30.5

Figures 6-8 and 6-9 illustrate cost differences ($/plate) comparison between present work and LBNL 2014 cost model.

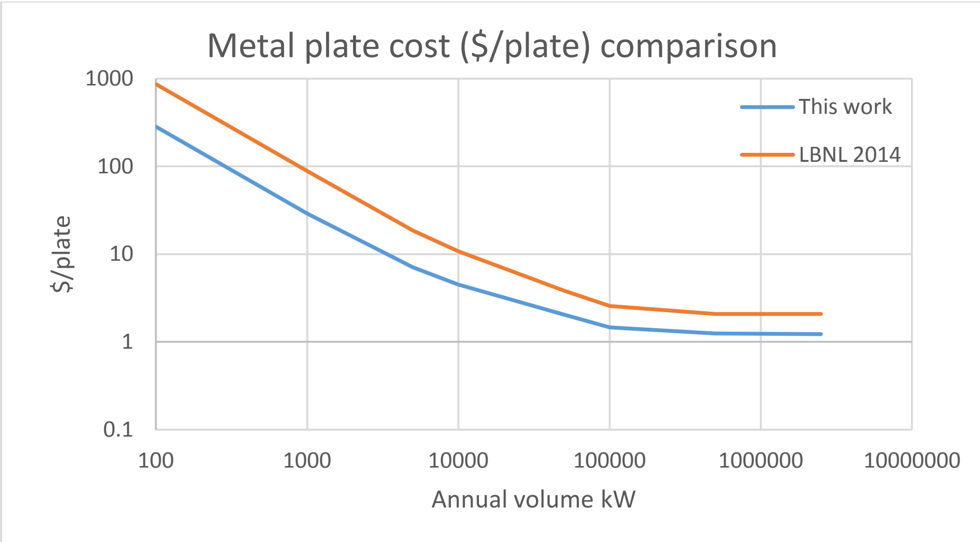


Figure 6-8 Metal plate cost comparison in term of $/plate

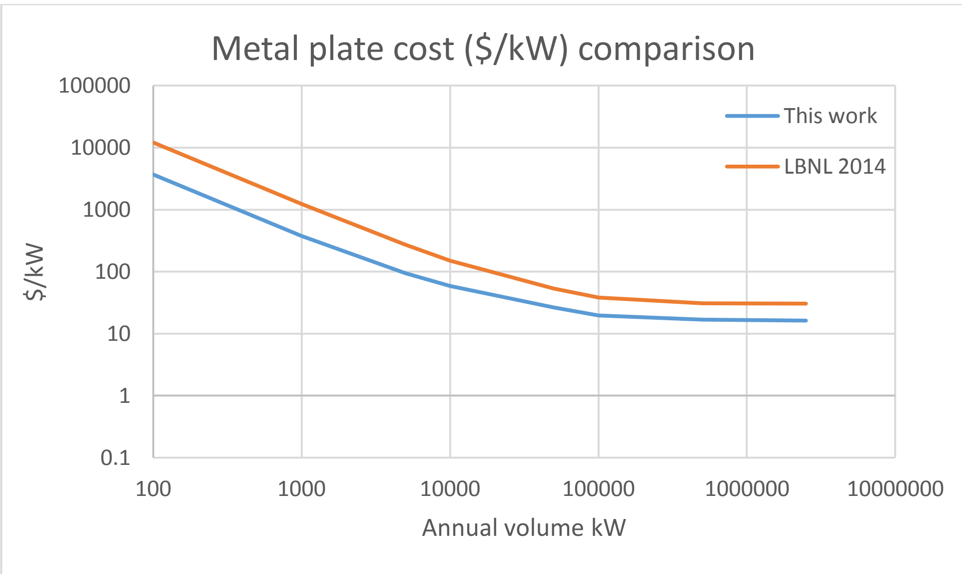


Figure 6-9 Metal plate cost comparison in term of $/kW

Two reasons for lower cost are a lower discount rate, that affects principally low production volume, and a lower stainless steel price assumption that affects principally high production volume

6.3.3.1 Discount rate considerations

Two different cases, with 10% and 15% of discount rate, are analyzed. Figure 6-10 illustrates the cost results at low production volume (< 10 MW), where capital cost is a larger portion of the overall metal plate cost.

Table 6-15 Discount rate comparison cost results

Discount comparison								
Annual volume (kW)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
$/plate with a discount rate of 10%	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
$/plate with a discount rate of 15%	365.48	37.07	8.65	5.32	2.43	1.71	1.45	1.41

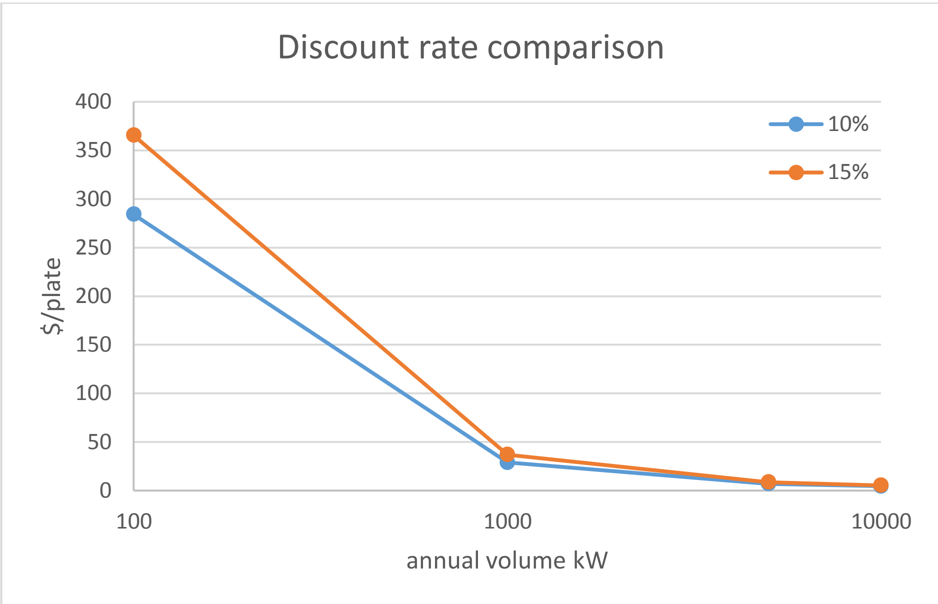


Figure 6-10 Discount rate comparison

At annual production volume of 100 kW, a 15% of discount rate increases the total cost almost of 30% ($365.5/plate), compared to a 10% of discount rate ($284.3/plate).

6.3.3.2 Stainless steel price considerations

Four models with different stainless steel price are analyzed; respectively with $11/kg, $7/kg, $4/kg, $2/kg. As can be noted in Figure 6-11, different cost curves diverge when annual production volume increase. This is a direct consequence of material cost influence at high production volume.

Table 6-16 SS 316L price comparison cost results

SS 316L comparison								
Annual volume (kW)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
$11/kg	284.75	29.40	7.52	4.96	2.46	1.87	1.64	1.61
$7/kg	284.50	29.15	7.27	4.70	2.22	1.63	1.42	1.39
$4/kg	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
$2/kg	284.18	28.83	6.95	4.38	1.92	1.34	1.14	1.11

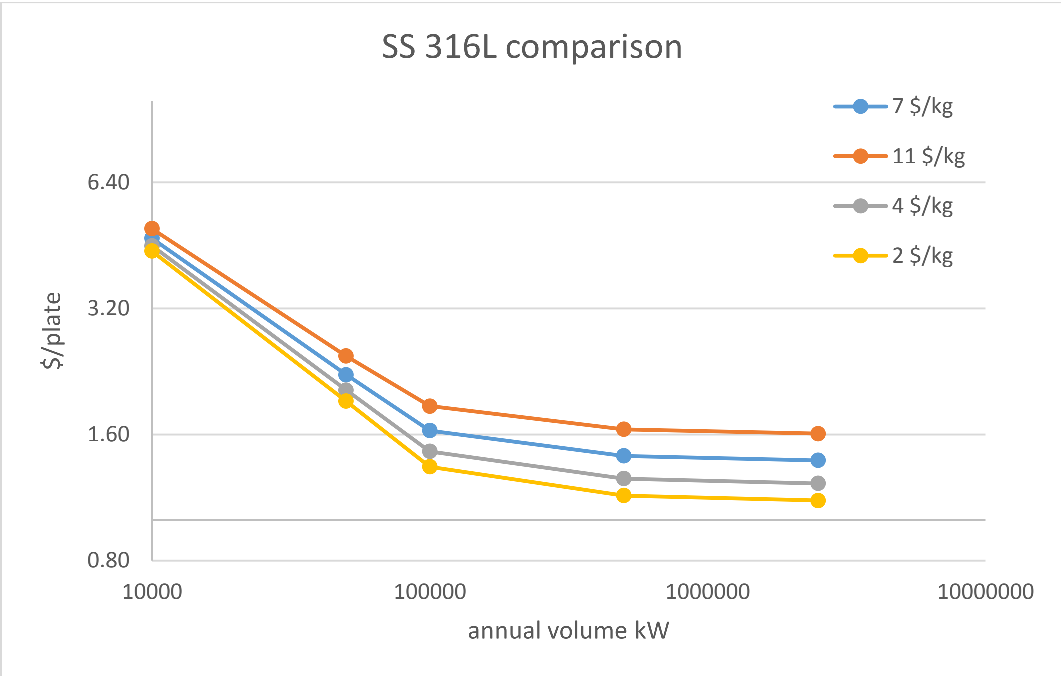


Figure 6-11 Different stainless steel 316L prices comparison

At annual production volume of 100 MW (10 kW at 10,000 systems per year), a $11/kg of stainless steel price increases the total cost by almost 30% ($1.87/plate) compared to a $4/kg price ($1.46/plate).

6.3.4 Metal bipolar plate cost sensitivity

Bipolar plates cost sensitivity analysis is performed for 50 kW systems at different production volumes. The impact to the cost in $/kW is calculated for a ±20% change in the sensitivity parameter being varied.

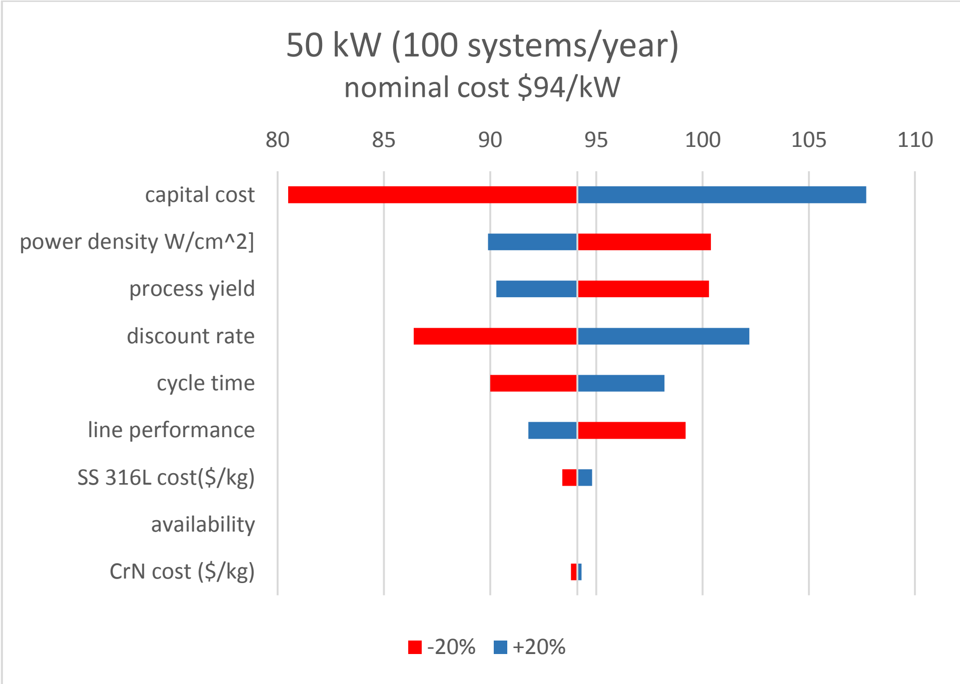


Figure 6-12 Metal plate sensitivity for 50 kW and 100 systems/year

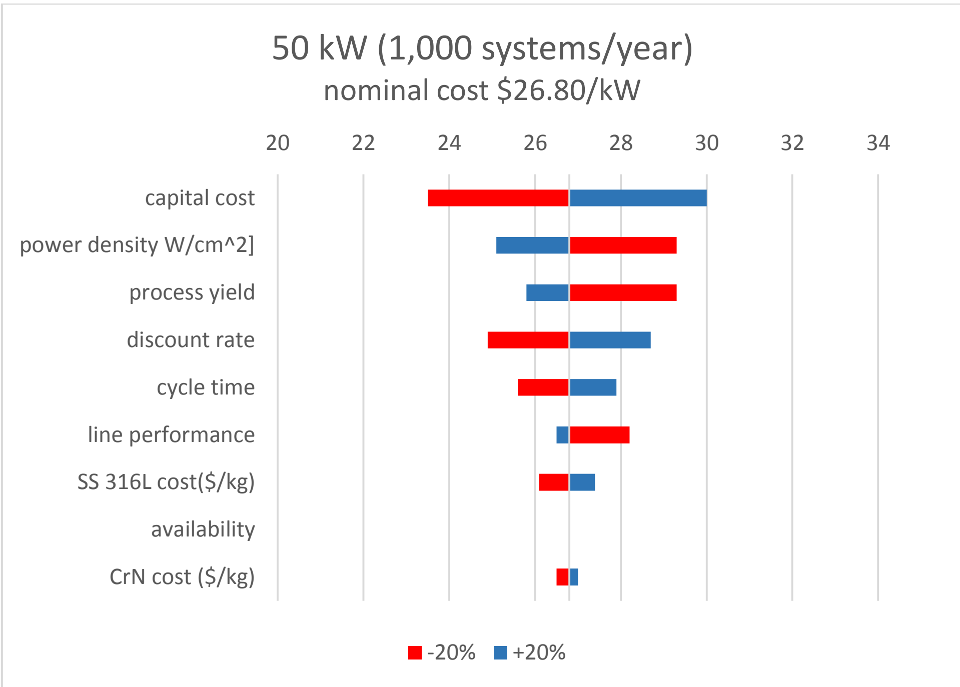


Figure 6-13 Metal plate sensitivity for 50kW and 1,000 systems/year

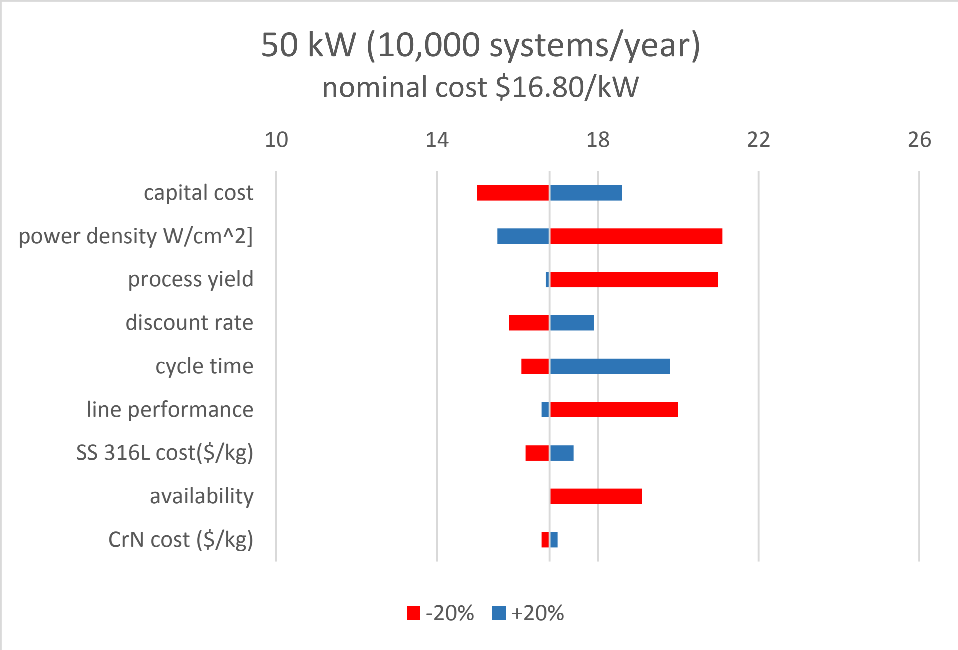


Figure 6-14 Metal plate sensitivity for 50 kW and 10,000 systems/year

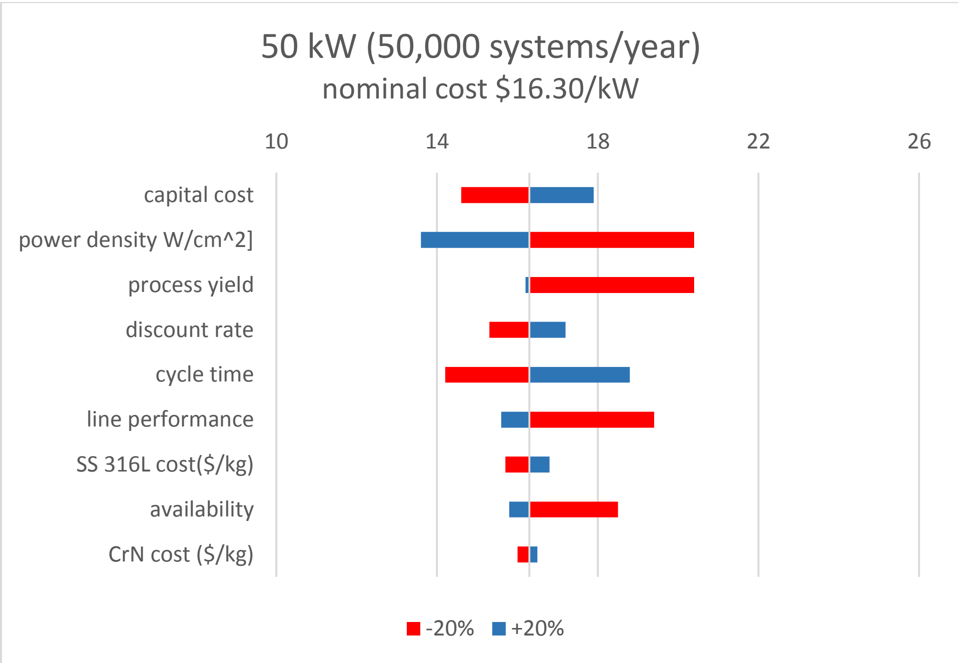


Figure 6-15 Metal plate sensitivity for 50 kW and 50,000 systems/year

Process yield and power density are important components at all volumes. Capital cost dominates at low volume (100 and 1,000 systems/year). Interconnect cost sensitivity in case of line performance variation is not symmetric because a +20% increase of this parameter is not applicable. Nominal values are equal to 89% and 95% in manual and automatic configurations respectively.

6.4 Alternative metal plates processes

This chapter has the purpose of presenting alternative metal plates manufacturing, in order to decrease the production cost. Given the nature of these exploratory case studies, assumptions made are critical.

6.4.1 High speed bipolar plates manufacturing

High velocity metal plates manufacturing have been investigated in a study conducted by AP&T, Sandvik and Cell impact [27].

The idea for this study is to achieve bipolar plates cost reductions through the combination of:

- Pre-coated stainless steel
- High-speed forming
- Automated line

By using readily available materials, and reducing process steps, cost reductions can be achieved.

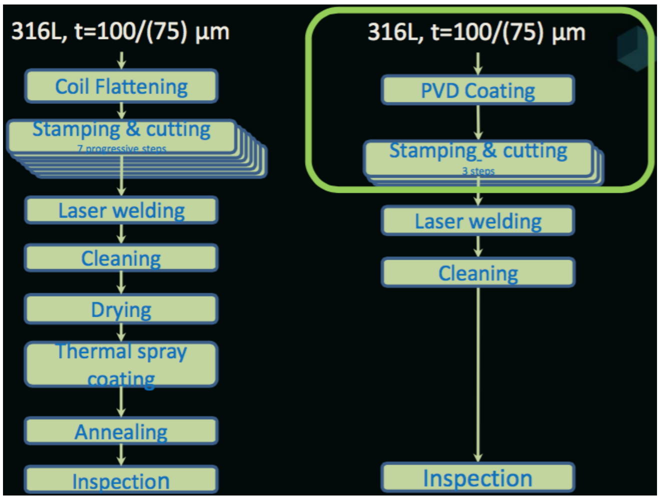


Figure 6-16 Comparison between typical process and alternative process from Sandvik [27]

The stamping and cutting process is divided into 3 steps:

1. Preform and precutting
2. High-velocity forming
3. Cutting and positioning

A two-step forming process is utilized to obtain a more uniform cross-section, less necking and difficult patterns.

Using a pre-coated stainless steel (SS considered in the report is Sanergy LT 316L by Sandvik), the bottleneck time can be shifted from PVD process to stamping process. A high-speed stamping process enables high production volume and also improves the performance of the material.

Material properties and elongation are dependent on the forming speed. Elongation is increasing when the forming speed exceeds 1-2 m/s. The key advantages of high speed forming are as follows:

- At low speed: micro voids coalesce, forming a crack, perpendicular to loading;

- At high speed, micro void joining is retarded due to thermal effects, and they grow in an angled direction.

Figure 6-17 shows the effects of high-speed forming on Sanergy LT316L.

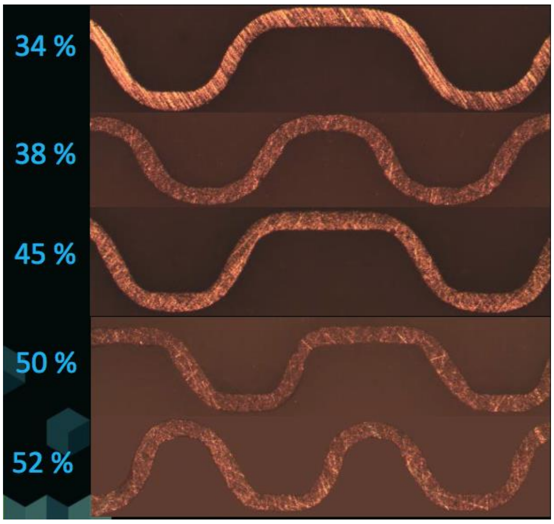


Figure 6-17 High velocity formed patterns [27]

Channel forming elongation increases from 34% to 52%. The channel pitch varies between 0.9 mm to 1.6 mm.

6.4.1.1 Stainless steel coating considerations

In this paragraph, pre-coated stainless steel is modeled as a commodity part rather than being manufactured in-house. The assumed price trend used in this study is shown in Figure 6-18. This curve shows the price of 0.1 mm stainless steel thickness with 20 nm of graphite-like-carbon (GLC) coating, as quoted by Sandvik; however, a declination in price with volume is expected due to economy of scale.

Figure 6-18 Pre-coated SS price trend over quantity

Table 6-17 GLC-coated SS quotes from Sandvik

GLC coated Stainless Steel			
Order quantity (kg)	100	1,000	100,000
Price ($)	40	28-30	18-20

The coating used in this process, GLC, is different compared to the coating analyzed in the present work, CrN. Also the thickness is different, 20 nm for graphite like carbon and 400 nm for chromium nitride. Cost of graphite like carbon less expensive than CrN is assumed.

However the cost fraction of CrN on the overall cost is negligible at low production and less than up to 7% at highest production. For this reason a direct comparison between the CrN-coated plated modeled in this work and the novel GLC-coated plate process is considered acceptable. Figure 6-19 shows the CrN cost fraction of the total plate cost.

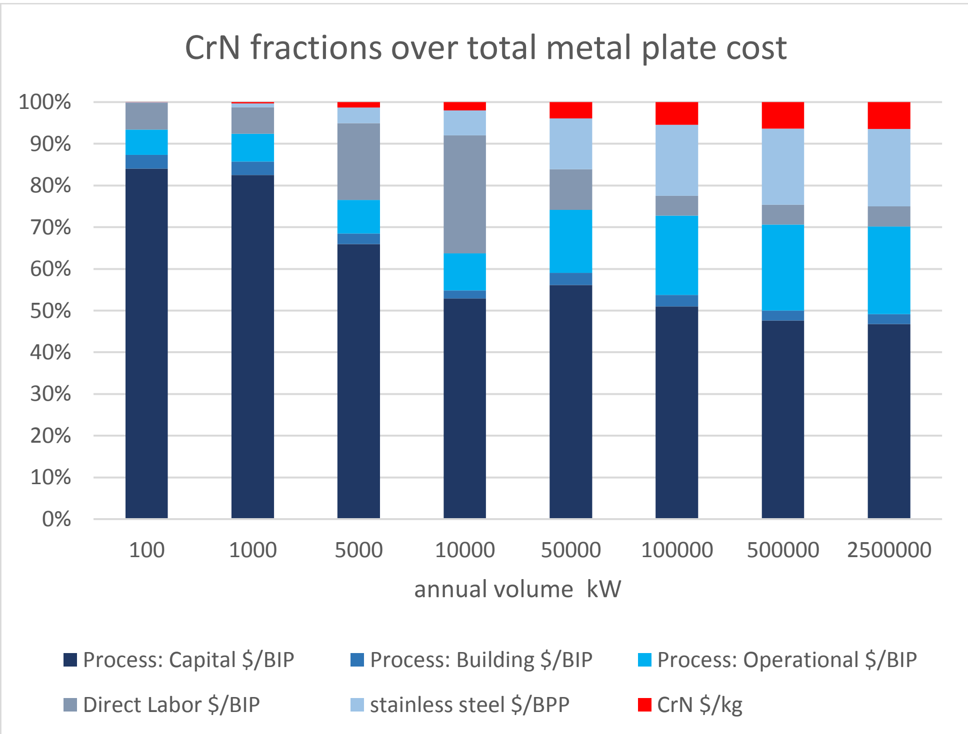


Figure 6-19 CrN fractions over total metal plate cost

6.4.2 Pre-coated stainless steel cost summary

Tables 6-18, 6-19 and 6-20 report the cost results for 1 kW, 10 kW and 50 kW systems considering pre-coated stainless steel as purchased; the process flow is the same described in paragraph 6.3.1 but without PVD.

Table 6-18 GLC pre-coated metal plate cost summary for 1 kW system

System size (kW)	1 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	175.27	17.53	1.75	0.62
Direct Labor $/plate	18.27	1.83	1.28	0.20
Direct Materials $/plate	2.70	2.12	1.65	1.33
Process: Operational $/plate	12.58	1.31	0.18	0.07
Process: Building $/plate	7.92	0.79	0.08	0.04
Final Cost $/plate	216.73	23.57	4.94	2.26

Table 6-19 GLC pre-coated Metal plate cost summary for 10 kW system

System size (kW)	10 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	16.88	1.69	0.38	0.30
Direct Labor $/plate	1.76	1.28	0.07	0.06
Direct Materials $/plate	2.11	1.64	1.20	0.97
Process: Operational $/plate	1.26	0.18	0.05	0.04
Process: Building $/plate	0.76	0.08	0.03	0.02
Final Cost $/plate	22.77	4.87	1.73	1.40

Table 6-20 GLC pre-coated Metal plate cost summary for 50 kW systemSystem size (kW)	50 kW			
Systems/year	100	1,000	10,000	50,000
Process: Capital $/plate	3.43	0.61	0.31	0.29
Direct Labor $/plate	1.30	0.20	0.06	0.06
Direct Materials $/plate	1.79	1.33	0.97	0.81
Process: Operational $/plate	0.30	0.07	0.04	0.04
Process: Building $/plate	0.15	0.04	0.02	0.02
Final Cost $/plate	6.97	2.24	1.41	1.22

Figures 6-20, 6-21 and 6-22 show the fraction of bipolar plate costs as a function of annual production volume for 1 kW, 10 kW and 50 kW system.

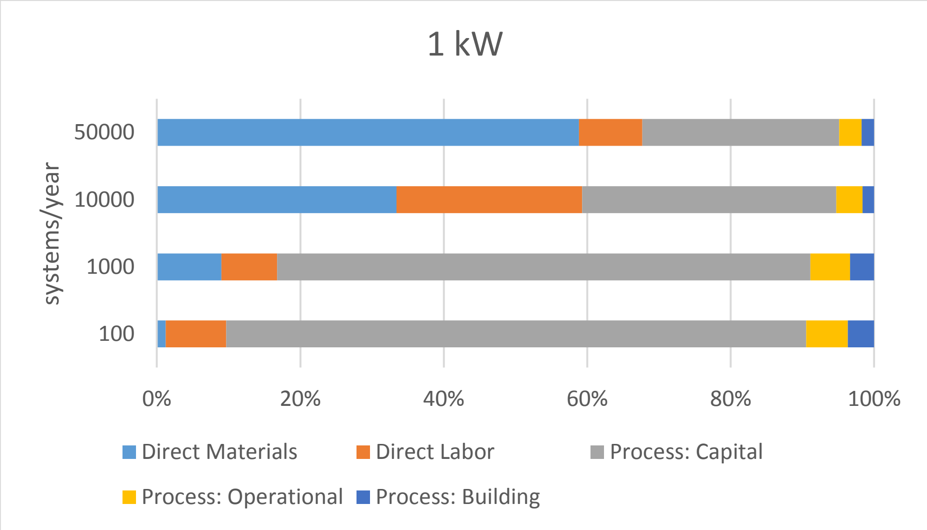


Figure 6-20 Percentage cost breakdown for GLC pre-coated metal plate, for 1 kW system

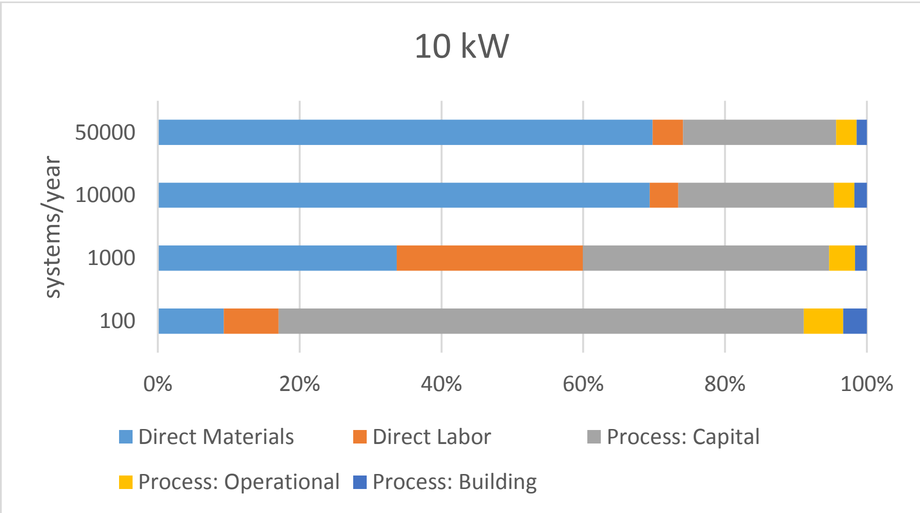


Figure 6-21 Percentage cost breakdown for GLC pre-coated metal plate, for 10 kW system

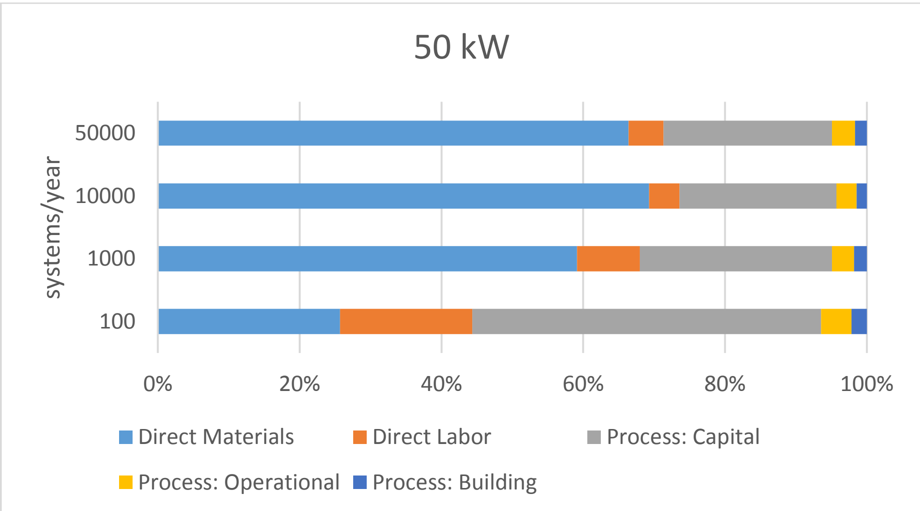


Figure 6-22 Percentage cost breakdown for GLC pre-coated metal plate, for 50 kW system

The material cost is more significant than in the uncoated stainless steel case; In fact, for 50 MW, it is the principal cost component making up almost 70% of the total cost.

At 1 MW and 5 MW of annual production volume, capital cost is the 70-50% of the total cost and at over 10 MW capital cost is 20-30% of the total cost. Another aspect is the reduction of operational costs, compared to previous case, due to the elimination of physical vapor deposition process.

Table 6-21 shows $/plate and $/kW metal plate cost comparison, over annual volume (kW).

Table 6-21 Metal plate cost comparison between CrN batch PVD and GLC pre-coated

Annual Production Volume (kW/ year)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/plate)	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
GLC pre-coated ($/plate)	216.73	23.57	6.97	4.94	2.26	1.73	1.40	1.22
CrN batch PVD ($/kW)	3,696	376.4	94.1	58.6	26.5	19.7	16.9	16.3
GLC pre-coated ($/kW)	2,818	306.5	92.7	64.3	29.4	23.3	18.9	16.3

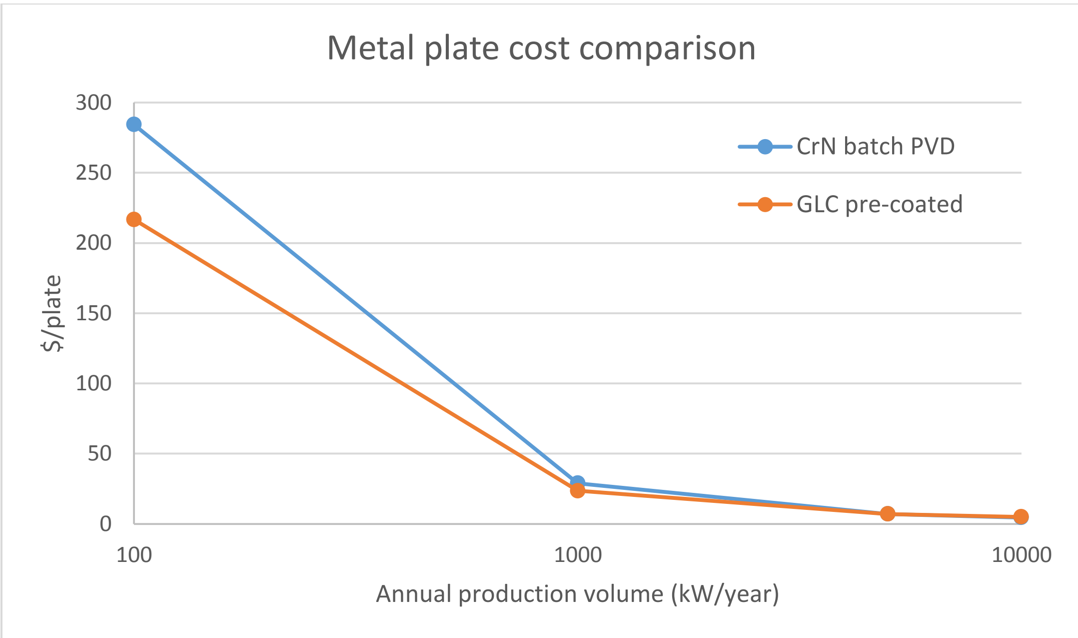


Figure 6-23 Metal plate cost $/plate comparison between CrN batch PVD and GLC pre-coated

Despite the material cost increase, at low production volume the main component is the capital cost, and the elimination of the PVD process leads to an overall decrease in the cost. At 100 kW the cost reduction is 24%, from about $3,700/kW to $2,800/kW.

6.4.3 High-speed considerations

In this section, a high-velocity stamping process in a fully automated configuration is considered. The cycle time per bipolar plate assumed in this analysis is 3 s/plate and the high-velocity stamping equipment cost the same as the base case. An overall comparison of bipolar plates cost is shown in Table 6-22.

Table 6-22 High-speed BPP cost comparison

Annual Production Volume (kW/ year)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/plate)	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
GLC pre-coated & high-speed stamping ($/plate)	216.73	23.57	6.97	4.94	2.26	1.68	1.18	1.00

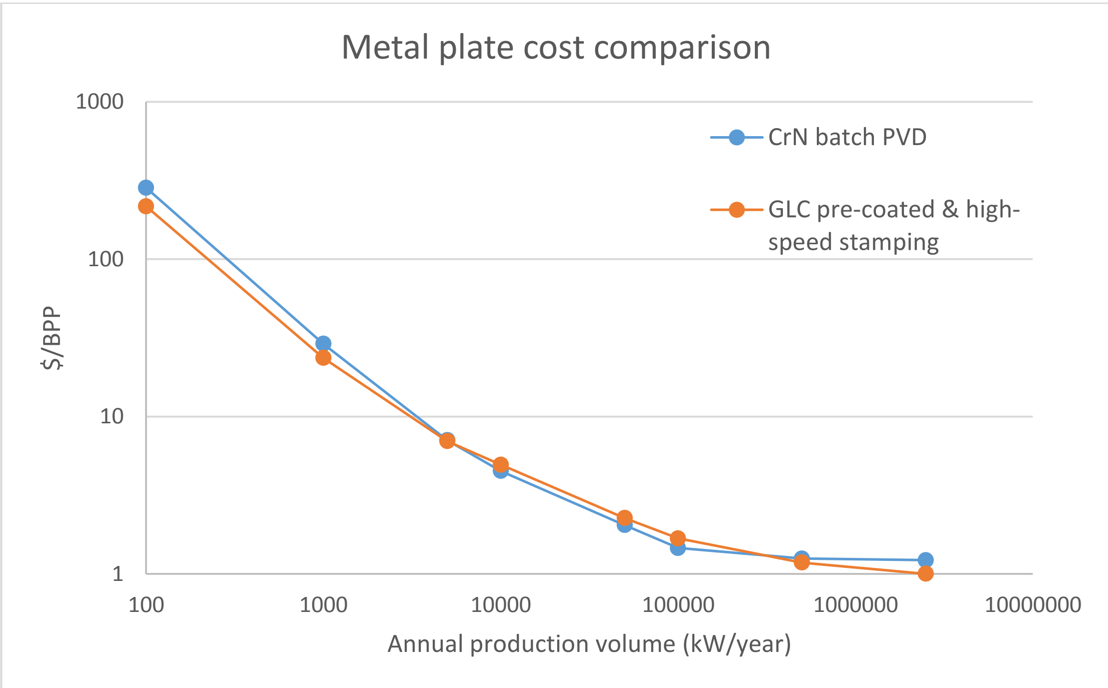


Figure 6-24 High-speed BPP cost comparison

At high production volume there is a cost reduction due to high speed stamping process since increasing the process speed reduces the number of lines and consequently also capital cost decrease. At mid production volume, the capital cost reduction is not sufficient to decrease the total bipolar plate cost, in this part of the graph the material cost is the predominant cost component and pre-coated SS is more expensive than uncoated SS. At low production volumes, the batch PVD process has higher costs due to the high capital costs of the PVD deposition.

Thus purchasing pre-coated stainless steel can evidently be advantageous from a cost standpoint, compared to the base case, particularly at low production volume, until about 5 MW annual volume, under the assumptions made here.

6.4.4 Pre-coated stainless steel manufactured in-house

The purpose of this chapter is to analyze the pre-coated stainless steel as manufactured in-house. A PVD process with roll to roll type continuous evaporation coating of full width strip steel is considered.

Complex coatings with multiple-layer options are applied to a strip in motion. The pre-treatment ensures a clean metallic surface, with a good adhesion between the substrate and the coating. The process assumed for our study is a Sandvik system, with the simplified equipment scheme as shown in Figure 6-25.

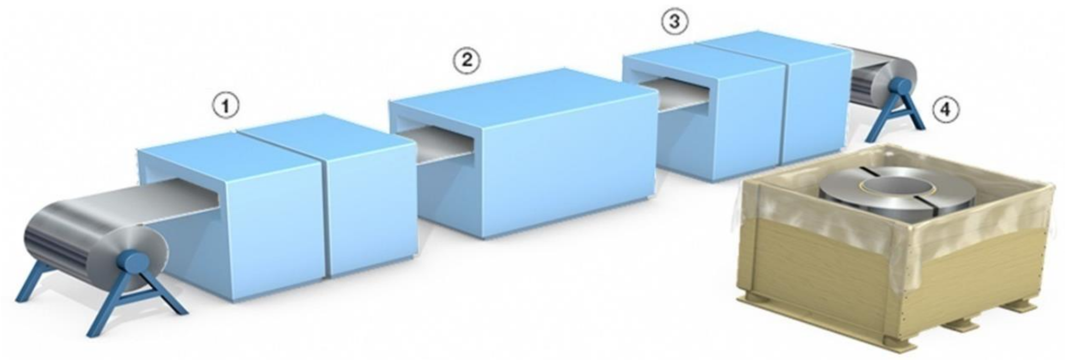


Figure 6-25 Roll to roll coating process line from Sandvik

The process is subdivided into 4 principal steps:

1. Cleaning/inspection. This is important for good adhesion. To avoid harmful defects, the whole area of the strip surface is inspected.
2. Coating: the PVD process in this work is assumed to be sputtering deposition.
3. Inspection: automatic x-ray inspection devices measure the thickness and quality of the coating.
4. Testing slitting and packaging: after coating, the steel strip is inspected and tested. The process is completed by slitting to the required width, control of burr height, width and shape, and finally by packaging and shipment.

6.4.4.1 Roll to roll vapor deposition

High throughput and low cost are the factors that differentiate roll to roll (R2R) manufacturing from batch processing manufacturing which can be slower and higher cost due to the multiple steps involved. Benefits of R2R processing include higher potential production rates and process yields. This technique can help reduce the cost of manufacturing through economy of scale as it allows devices to be fabricated automatically in mass quantities. Although initial capital cost is higher, these costs can often be recovered through the economic advantages realized at high volume production. A roll to roll deposition process is shown in Figure 6-26.

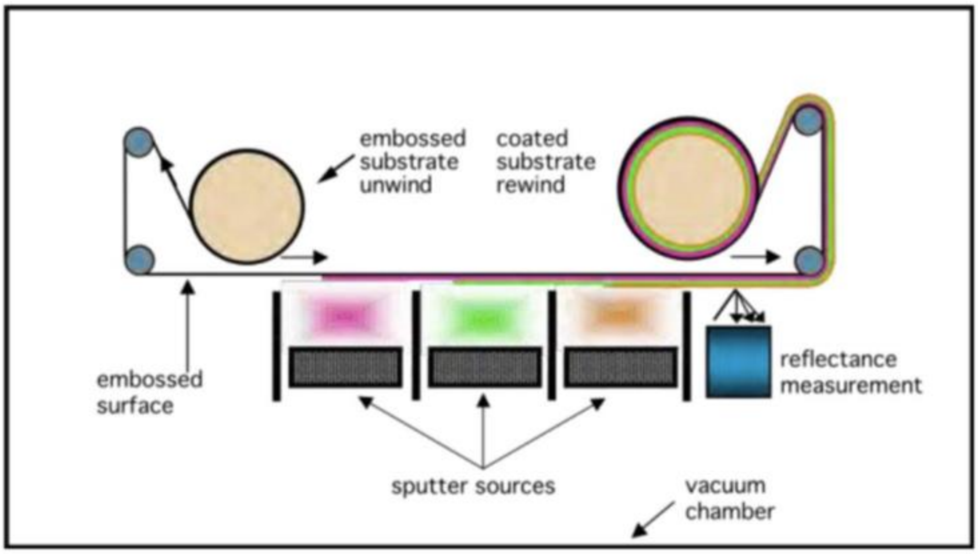


Figure 6-26 Roll to roll deposition [28]

The entire roll is loaded into a vacuum system where it is relatively easy to sputter the coating material onto the substrate without crosstalk between sequential sputtering sources. When the substrate moves past the sputtering source, the deposition rate of material varies. The processing rate influences the thickness and sequence of layers in a multilayer coating which also depends on rotation speed (line speed), initial position and orientation of the substrate. Vapor deposition processes are typically used for very thin coatings, usually less than micrometer in thickness, referred to as thin-film processes [29].

6.4.4.2 Roll to roll sputtering deposition metal plate cost summary

Two configurations, whose assumptions are listed in Table 6-23, are considered.

Table 6-23 Roll to roll deposition line configurations

Configuration	A	B
Web width (m)	0.46	0.9
Line speed (m/min)	2	2
Capital cost $	5,760,000	8,625,000

We assume a cost factor increase of 3X for roll to roll deposition capital costs compared to batch processing manufacturing, based on inputs from roll to roll manufacturers. A cost analysis for 50 kW systems is reported in Table 6-24.

Table 6-24 Metal plate with pre-coated SS manufactured in-house cost analysis for a 50 kW backup system

System size (kW)	50			
Production volume (units/year)	100	1,000	10,000	50,000
Configuration	A	A	B	B
Max Web Width (m)	0.46	0.46	0.90	0.90
Line Speed (m/min)	2	2	2	2
BIP simultaneously	4	4	8	8
number of lines	1	1	1	4
BIP required/ year	66500	665000	6650000	33250000
line utilization	2.27%	18.74%	77.55%	93.76%
required roll length	7237	67895	313839	1545540
process yield	85.00%	90.60%	98.00%	99.50%
line availability	80.00%	85.80%	93.50%	95.00%
setup time	60.00	21.85	6.31	5.00
workers/line	2	2	2	2
shift hour	16	16	16	16
max carrier length/line/day	1824	1824	1824	1824
max carrier length/line/year	350208	375598	409305	415872
max carrier length/line/year(+setup)	318269	362219	404717	412119
setup/year	8	68	314	1546
annual operating hours (+ setup)	71.5	663.6	3067	15103
Labor cost	4262	39562	182853	900463
Maintenance factor	0.10	0.10	0.10	0.10
Power Consumption (kW)	500	500	750	750
Initial Capital ($)	5760000	5760000	8625000	34500000
Initial System Cost ($)	6336000	6336000	9487500	37950000
Annual Depreciation ($/yr)	376320	376320	563500	2254000
Annual Cap Payment ($/yr)	750182	750182	1123320	4493280
Maintenance ($/yr)	68198	68198	102120	408480
Salvage Value ($/yr)	2088	2088	3127	12507
Energy Costs ($/yr)	4464	41438	287286	1414746
Property Tax ($/yr)	23962	23962	35880	143520
Building Costs ($/yr)	22440	22440	22440	89760
Machine Cost ($/yr)	867158	904132	1567920	6537279
Capital	748094	748094	1120193	4480773
Variable	72662	109636	389406	1823226
Building	46402	46402	58320	233280
material yield	0,62	0,74	0,85	0,85
316L (kg)	4450	41750	385971	1900764
CrN (kg)	119	1114	10299	50719
material cost	23025	216020	1997085	9834889
Total costs (R2R)	890183	1120152	3565004	16372168
Total costs(R2R) /plate	13,39	1,68	0,54	0,49

Table 6-25 shows the comparison between the base case, with a batch PVD, and a second case using CrN pre-coated stainless steel manufactured in-house, through a roll to roll deposition process.

Table 6-25 CrN batch PVD and R2R CrN pre-coated SS metal plate cost ($/BPP) comparison

Annual Production Volume (kW/ year)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/BPP)	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
R2R CrN pre-coated SS ($/BPP)	878.16	88.29	18.57	10.34	2.64	1.54	0.97	0.91

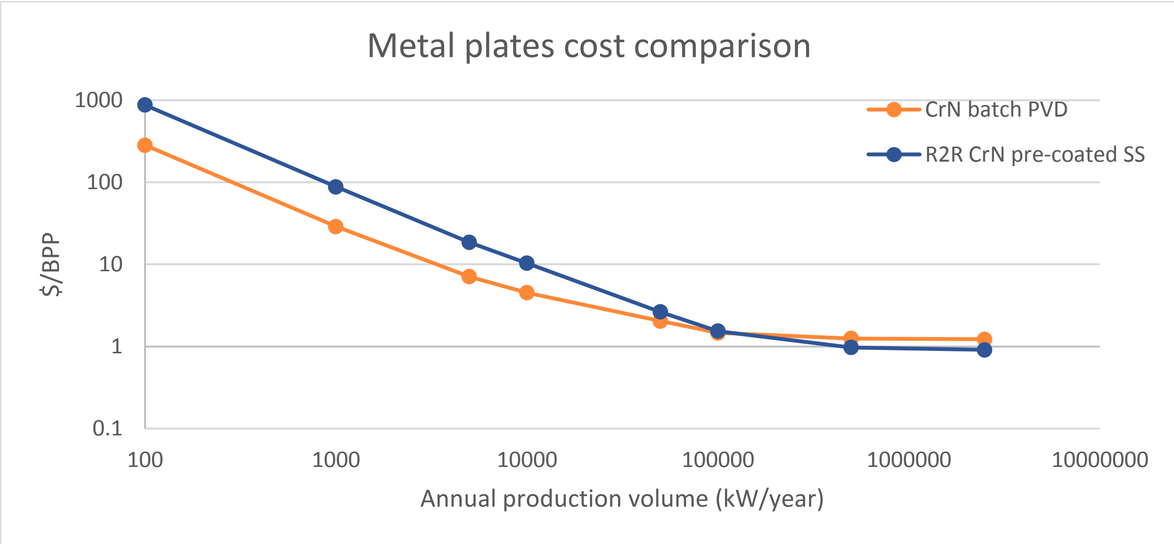


Figure 6-27 CrN batch PVD and R2R CrN pre-coated SS metal plate cost ($/BPP) comparison

At low production volume the roll to roll case is more expensive due to its high capital cost. At high production rate roll to roll process is less expensive. At high volumes, the number of lines is strongly reduced allowing a decrease of capital cost[1]. A roll to roll process appears to be favorable at an annual volume of about 100 MW.

Table 6-26 illustrates the comparison between the base case, with a batch PVD, and a second case using CrN pre-coated stainless steel manufactured in-house, through a roll to roll deposition process, and a high-velocity stamping process.

Table 6-26 CrN batch PVD and R2R CrN pre-coated SS & high-speed metal plate cost ($/BPP) comparison

Annual Production Volume (kW/ year)	100	1,000	5,000	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/BPP)	284.30	28.95	7.07	4.51	2.04	1.46	1.25	1.22
R2R CrN pre-coated SS & high-speed stamping ($/BPP)	878.16	88.29	18.57	10.34	2.64	1.49	0.75	0.69

[1] At 2,500 MW batch PVD capital cost is ~54 M, roll to roll PVD is ~34 M, with 19 lines and 4 lines, respectively.

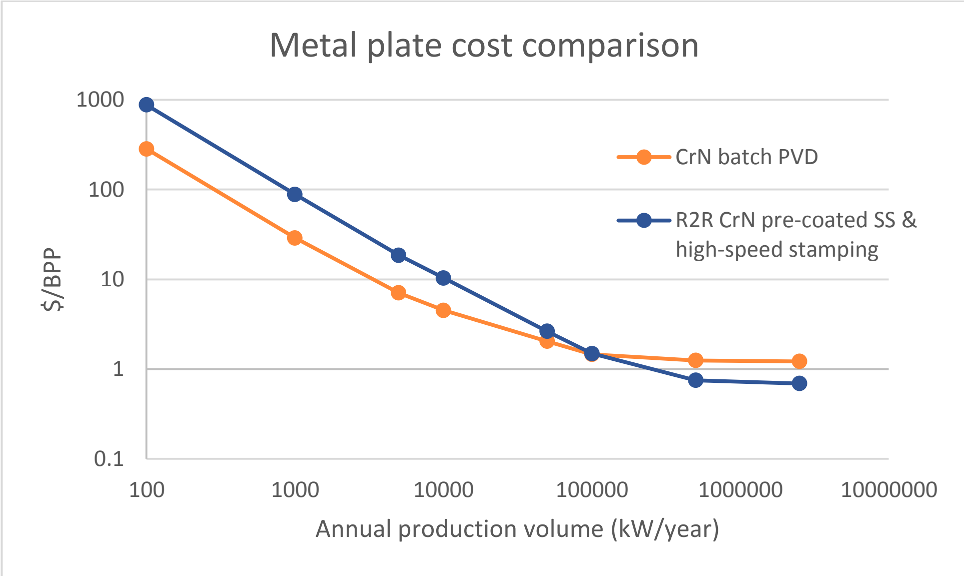


Figure 6-28 CrN batch PVD and R2R CrN pre-coated SS & high-speed metal plate cost ($/BPP) comparison

By considering a high-speed stamping process the total cost at high production volume decreases further because the number of lines are reduced. In this case the roll to roll process also starts to be favorable at 100 MW because high-velocity stamping is most advantageous in fully automated configurations at high production volumes.

6.4.4.3 Comparison between purchased and manufactured in-house pre-coated SS

Figure 6-29 compares the GLC-coated stainless steel price to the CrN-coated stainless steel manufactured in-house through the roll to roll process.

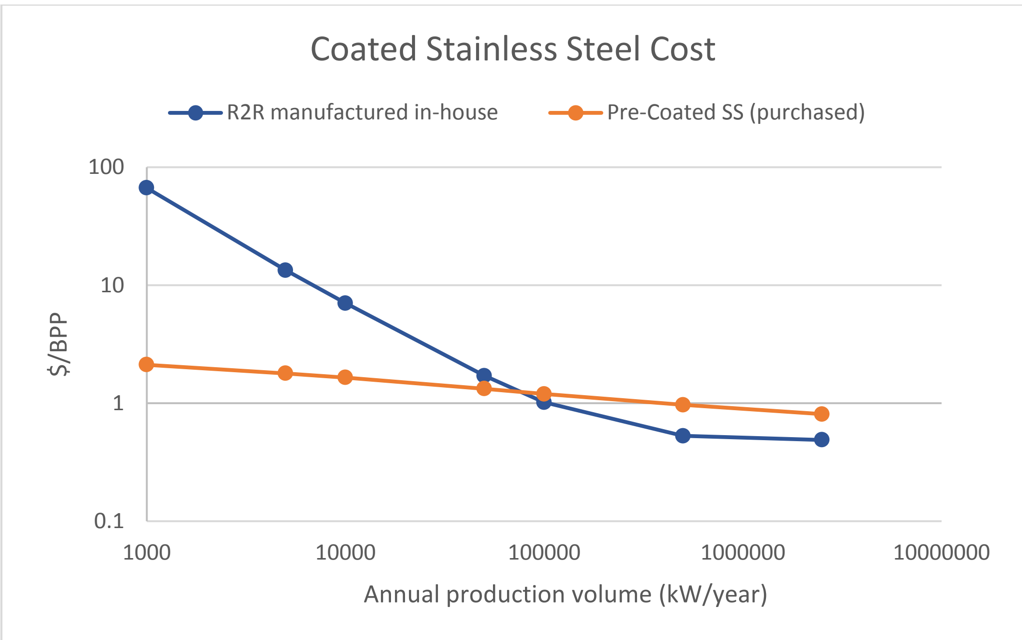


Figure 6-29 Comparison between purchased and manufactured in-house pre-coated SS

Roll to roll manufacturing process is convenient for an annual production >100MW.

Table 6-27 illustrates metal bipolar plate cost comparison at high production volume, analyzing three configurations that are taken into account in this section:

- CrN batch PVD
- GLC pre-coated SS & high-speed stamping
- R2R CrN pre-coated SS & high-speed stamping

Table 6-27 Metal plate cost ($/BPP) comparison at high production volume

Annual Production Volume (kW/ year)	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/BPP)	4.51	2.04	1.46	1.25	1.22
R2R CrN pre-coated SS & high-speed stamping ($/BPP)	10.34	2.64	1.49	0.75	0.69
GLC pre-coated SS & high-speed stamping ($/BPP)	4.94	2.26	1.68	1.18	1.00

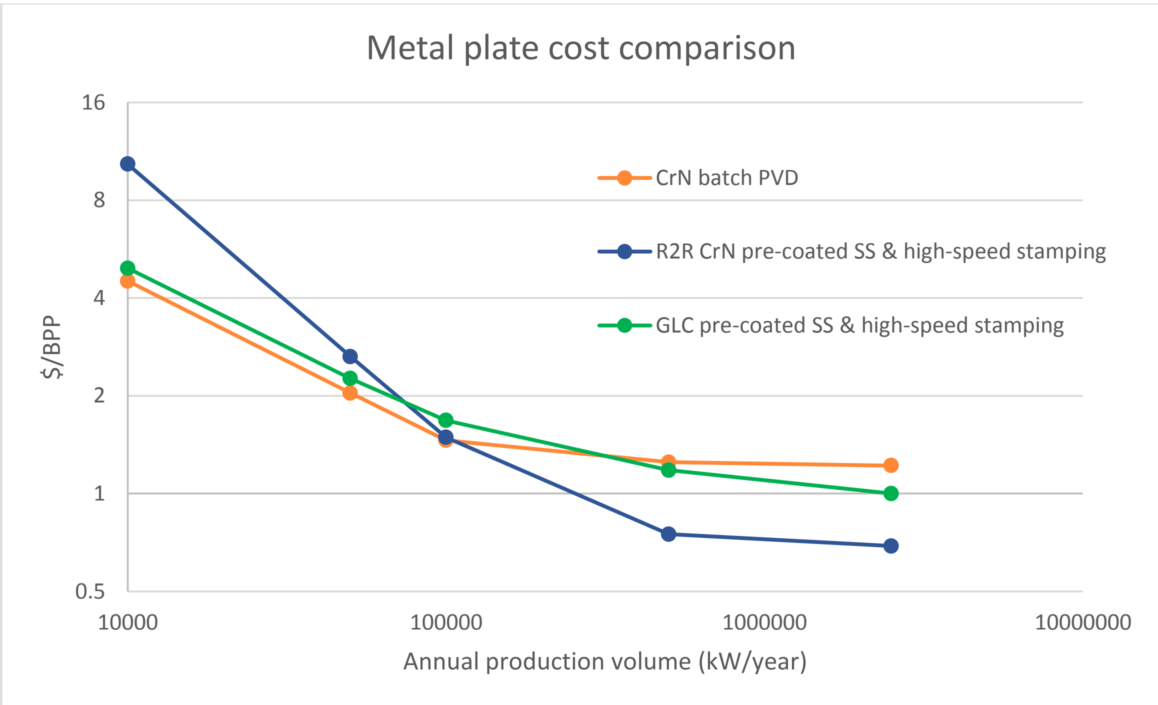


Figure 6-30 Metal plate cost ($/BPP) comparison at high production volume

At high production volume, the roll to roll coating stainless steel, coupled with a high-velocity stamping process, is the most cost effective configuration. This process reduces cost by 43% at 2,500 MW compared to the base case. A configuration with purchased pre-coated stainless steel, coupled with a high-speed stamping process, enables a cost reduction of 18% compared to the base case. Figure 6-31 shows the same comparison in terms of $/kW.

Table 6-28 metal plate cost ($/kW) comparison at high production volume

Annual Production Volume (kW/ year)	10,000	50,000	100,000	500,000	2,500,000
CrN batch PVD ($/kW)	58.6	26.5	19.7	16.9	16.25
R2R CrN pre-coated SS & high-speed stamping ($/kW)	134.4	34.4	19.7	9.8	7.85
GLC pre-coated SS & high-speed stamping ($/kW)	64.3	29.4	22.6	15.9	13.32

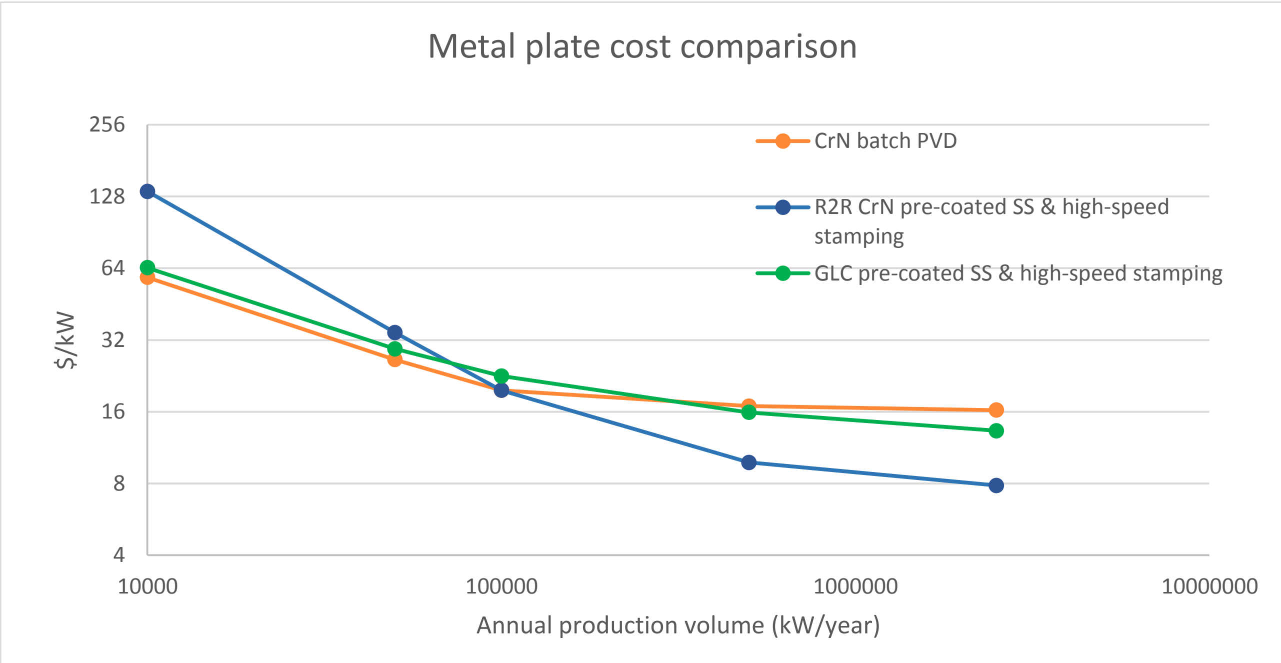


Figure 6-31 Metal plate cost ($/kW) comparison at high production volume

6.4.5 Make vs. buy analysis for metal plates

At low production volume, purchasing metal bipolar plates, instead of making them in-house, could be a better solution. There is a strong dependence between the metal bipolar plates and volume order as seen in representative market prices are shown in Table 6-29.

Table 6-29 Metal bipolar plate quotes from Borit

Annual volume (kW)	100	100,000	2,500,000
BPP/year	1,300	1,350,000	33,250,000
$/plate	35	8	4

The relationship between the costs of buying the metal plates versus the cost of making the plates in the two analyzed processes is shown in Figures 6-32 and 6-33.

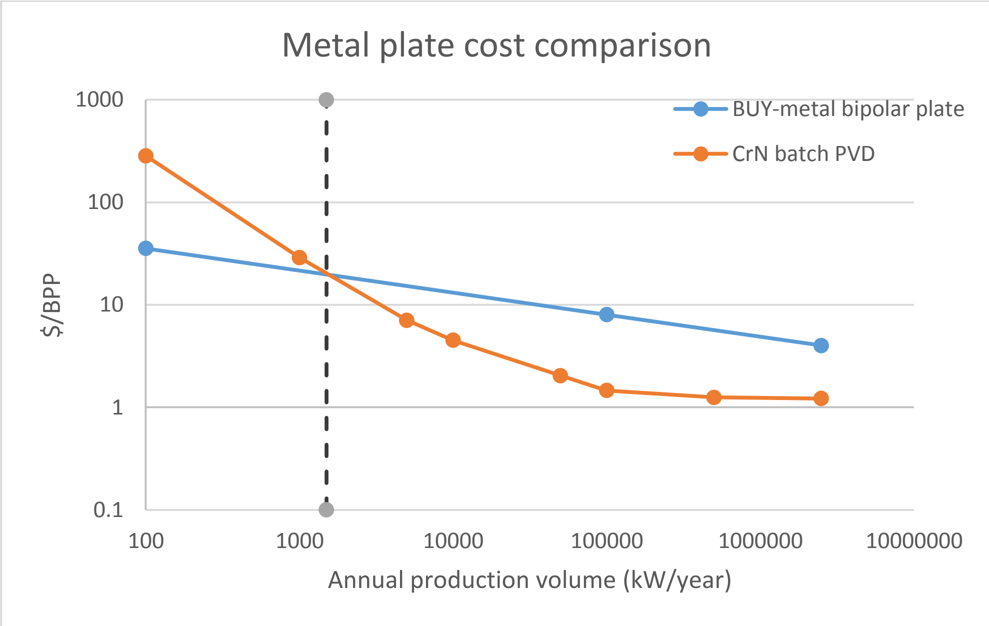


Figure 6-32 Modeled plate costs versus buy metal plate costs

At low production volumes, it is cheaper to buy the metal bipolar plates and at higher production volumes, it is cheaper to make the metal bipolar plates. The critical point in which the make option overtakes the buy option is when annual production volume exceeds about 1,500 kW per year.

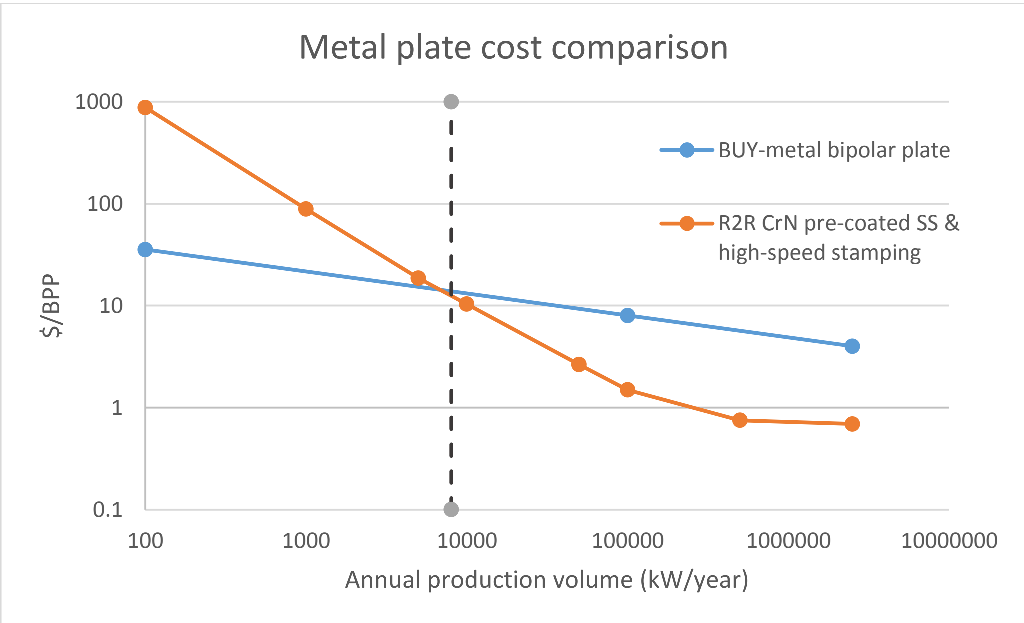


Figure 6-33 R2R pre-coated SS and high-speed stamping versus buy metal plate cost comparison

In the case of R2R CrN pre-coated SS and high speed stamping (Fig. 6-33), the critical point is shifted toward higher annual volumes because the higher capital cost of roll to roll process, to about 8,000 kW per year.

6.5 Stack assembly cost summary

The backup power cost model has been updated for the assembly, GDL, and frame/seal modules with backup functional specifications (single cell active area, number of cells per system). Tables 6-30, 6-31 and 6-32 illustrate assembly cost results for 1 kW, 10 kW and 50 kW backup power systems.

Table 6-30 Stack assembly cost results for 1 kW system

	1 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	203.00	163.40	131.72	119.05
Direct Labor ($/kW)	88.54	88.54	44.27	7.87
Process: Capital ($/kW)	292.83	29.28	13.13	5.07
Process: Operational ($/kW)	28.36	3.83	3.10	1.13
Process: Building ($/kW)	307.84	30.78	4.65	1.01
Final Cost ($/kW)	**920.58**	**315.83**	**196.88**	**134.13**

Table 6-31 Stack assembly cost results for 10 kW system	10 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	20.80	16.84	13.67	12.40
Direct Labor ($/kW)	8.85	4.43	0.79	0.79
Process: Capital ($/kW)	29.28	7.57	1.27	0.51
Process: Operational ($/kW)	2.89	0.83	0.16	0.12
Process: Building ($/kW)	30.78	2.73	0.25	0.10
Final Cost ($/kW)	**92.61**	**32.40**	**16.13**	**13.91**

Table 6-32 Stack assembly cost results for 50 kW system	50 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	4.26	3.55	2.98	2.75
Direct Labor ($/kW)	1.77	0.89	0.16	0.16
Process: Capital ($/kW)	5.86	1.51	0.25	0.10
Process: Operational ($/kW)	0.63	0.19	0.04	0.03
Process: Building ($/kW)	6.16	0.55	0.05	0.02
Final Cost ($/kW)	**18.67**	**6.69**	**3.48**	**3.06**

6.6 GDL cost summary

Tables 6-33, 6-34 and 6-35 illustrate gas diffusion layer cost results for 1 kW, 10 kW and 50 kW backup power systems.

Table 6-33 GDL cost results for 1 kW system

	1 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	145,36	115,47	87,47	69,86
Direct Labor ($/kW)	0,89	0,89	0,79	0,73
Process: Capital ($/kW)	2231,51	223,10	22,31	4,46
Process: Operational ($/kW)	159,54	16,07	1,71	0,43
Process: Building ($/kW)	21,70	2,17	0,22	0,04
Material Scrap ($/kW)	13,55	11,13	7,07	4,74
Final Cost ($/kW)	**2572,55**	**368,83**	**119,57**	**80,27**

Table 6-34 GDL cost results for 10 kW system	10 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	112,44	85,29	61,18	44,47
Direct Labor ($/kW)	0,86	0,77	0,69	0,32
Process: Capital ($/kW)	223,16	22,31	2,23	0,48
Process: Operational ($/kW)	16,06	1,71	0,26	0,15
Process: Building ($/kW)	2,17	0,21	0,02	0,01
Material Scrap ($/kW)	10,84	6,92	3,81	2,19
Final Cost ($/kW)	**365,54**	**117,22**	**68,19**	**47,61**

Table 6-35 GDL cost results for 50 kW system	50 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	92,43	67,47	44,07	27,92
Direct Labor ($/kW)	0,79	0,70	0,32	0,29
Process: Capital ($/kW)	44,64	4,46	0,47	0,38
Process: Operational ($/kW)	3,31	0,43	0,15	0,45
Process: Building ($/kW)	0,43	0,04	0,01	0,01
Material Scrap ($/kW)	7,96	4,60	2,17	1,01
Final Cost ($/kW)	**149,56**	**77,71**	**47,18**	**30,05**

6.7 Frame-seal cost summary

Tables 6-36, 6-37, 6-38 illustrate frame-seal cost results for 1 kW, 10 kW and 50 kW backup power systems.

Table 6-36 Frame-seal cost results for 1 kW system

	1 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	9.94	9.95	9.96	9.91
Direct Labor ($/kW)	7.00	6.72	6.45	2.51
Process: Capital ($/kW)	1272.61	123.99	12.07	5.58
Process: Operational ($/kW)	91.00	9.53	1.54	1.12
Process: Building ($/kW)	35.56	3.50	0.28	0.13
Material Scrap ($/kW)	376.88	46.51	15.71	11.72
Final Cost ($/kW)	1793.00	200.20	46.02	30.97

Table 6-37 Frame-seal cost results for 10 kW system	10 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	9.66	9.69	9.65	9.67
Direct Labor ($/kW)	6.53	6.28	2.45	2.45
Process: Capital ($/kW)	123.95	12.15	4.21	3.00
Process: Operational ($/kW)	9.52	1.50	0.95	0.82
Process: Building ($/kW)	3.40	0.27	0.10	0.07
Material Scrap ($/kW)	26.94	8.33	5.98	5.58
Final Cost ($/kW)	180.00	38.22	23.34	21.58

Table 6-38 Frame-seal cost results for 50 kW system	50 kW			
	100	1,000	10,000	50,000
Direct Materials ($/kW)	9.54	9.52	9.55	9.59
Direct Labor ($/kW)	6.31	2.41	2.42	2.36
Process: Capital ($/kW)	24.31	5.50	3.03	2.84
Process: Operational ($/kW)	2.42	1.07	0.81	0.81
Process: Building ($/kW)	0.67	0.13	0.07	0.07
Material Scrap ($/kW)	13.30	8.18	6.59	6.08
Final Cost ($/kW)	56.55	26.83	22.46	21.74

6.8 Backup PEM FC stack manufacturing cost results

Table 6-39 shows the overall stack costs ($/kW) for PEM FC in backup power condition, broken down by systems size and annual volume (kW).

Table 6-39 Stack manufacturing cost results

	1 kW	10 kW	50 kW
100 syst./year	11,464.0	1,427.3	527.4
1000 syst./year	1,679.0	429.0	285.9
10000 syst./year	607.2	267.4	211.1
50000 syst./year	425.3	222.4	176.8

The total stack costs decrease as the system size or annual volume increase. These trends can be seen in Figures 6-34 and 6-35.

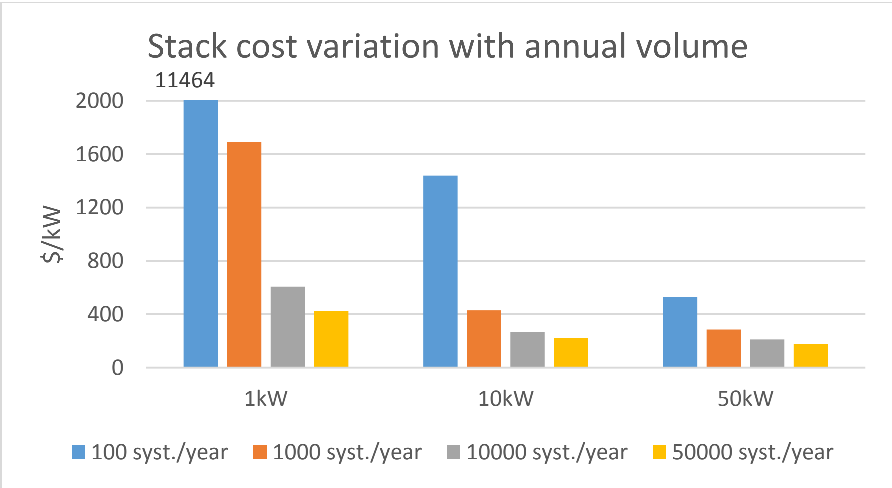


Figure 6-34 Stack manufacturing cost variation with annual production rate in ($/kW)

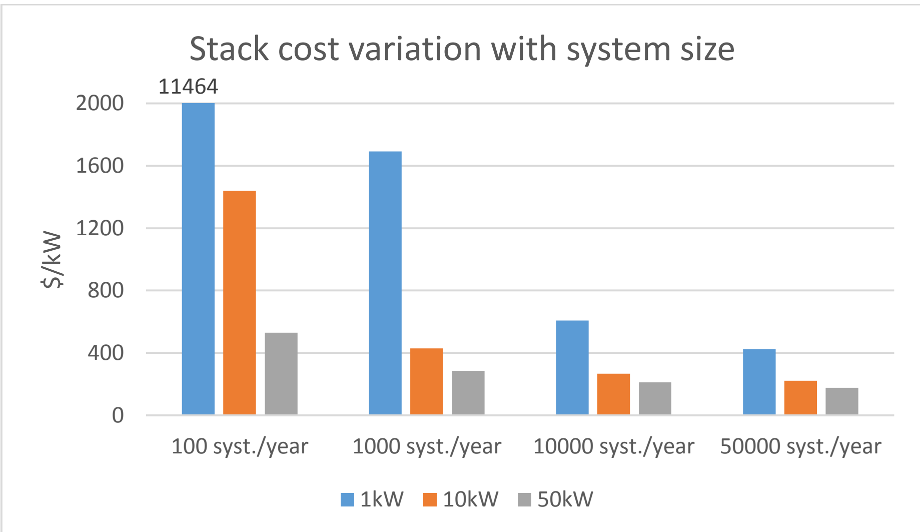


Figure 6-35 Stack manufacturing cost variation with system size in ($/kW)

As can be noted by these graphs, there is a greater cost reduction increasing system size than annual volume.

Detailed stack costing results are shown below for 10 kW and 50 kW stacks. Overall stack costs per kW drop as a function of production volume (100, 1,000, 10,000 and 50,000 systems per year) (Figure 6-36 and

Figure 6-37).

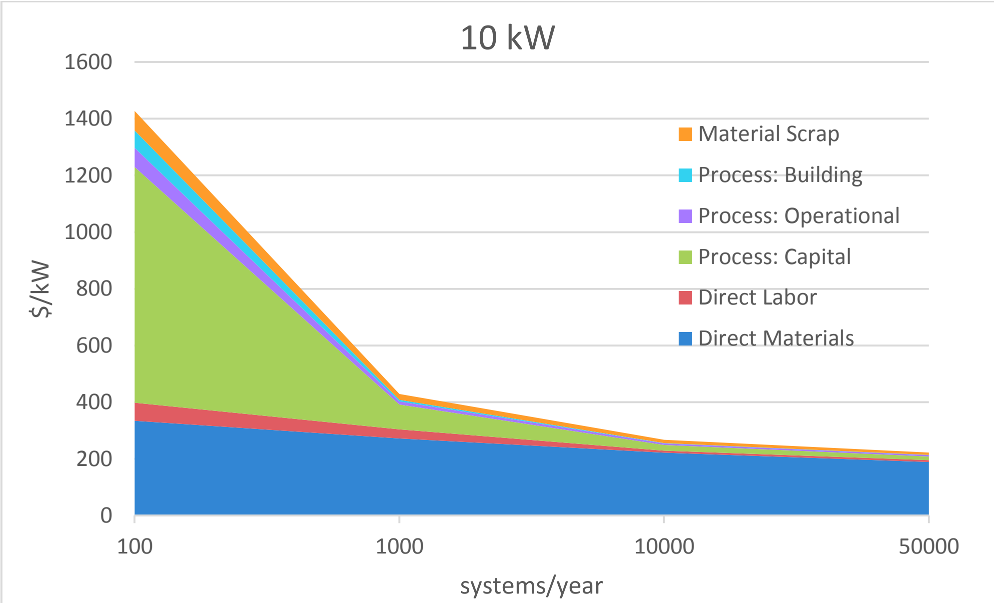


Figure 6-36 Stack cost as a function of annual production volume (systems/year) for 10 kW system

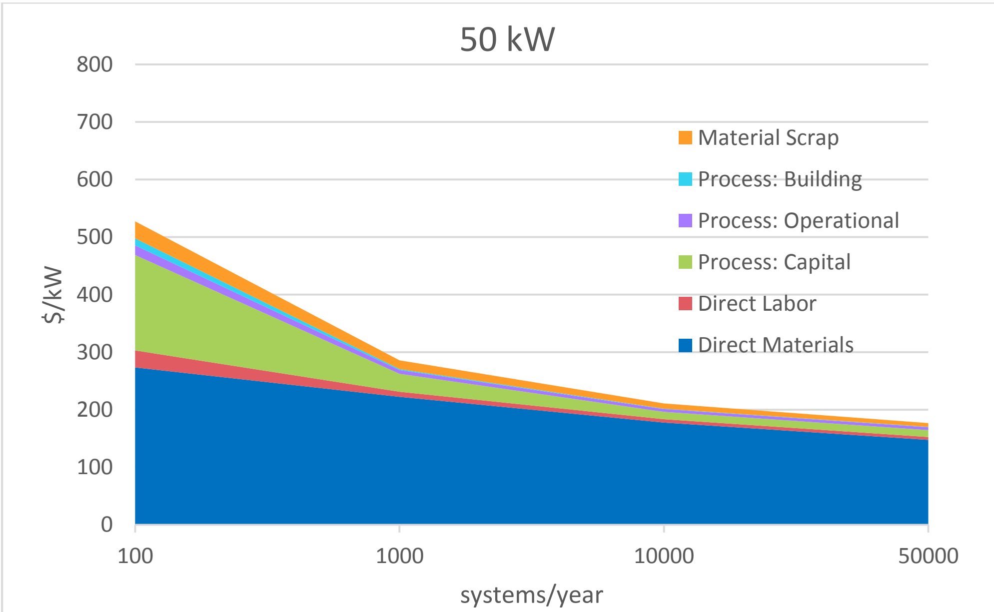


Figure 6-37 Stack cost as a function of annual production volume (systems/year) for 50 kW system

Figure 6-36 and Figure 6-37 show that material costs dominate at high volumes. At low volumes, capital cost also has a strong impact on overall stack cost since lower machine utilization is present. The trend of material cost is almost constant, due to the Pt cost contribution of the CCM. A breakdown of the stack cost at the stack components level is show in Figure 6-38 and Figure 6-39.

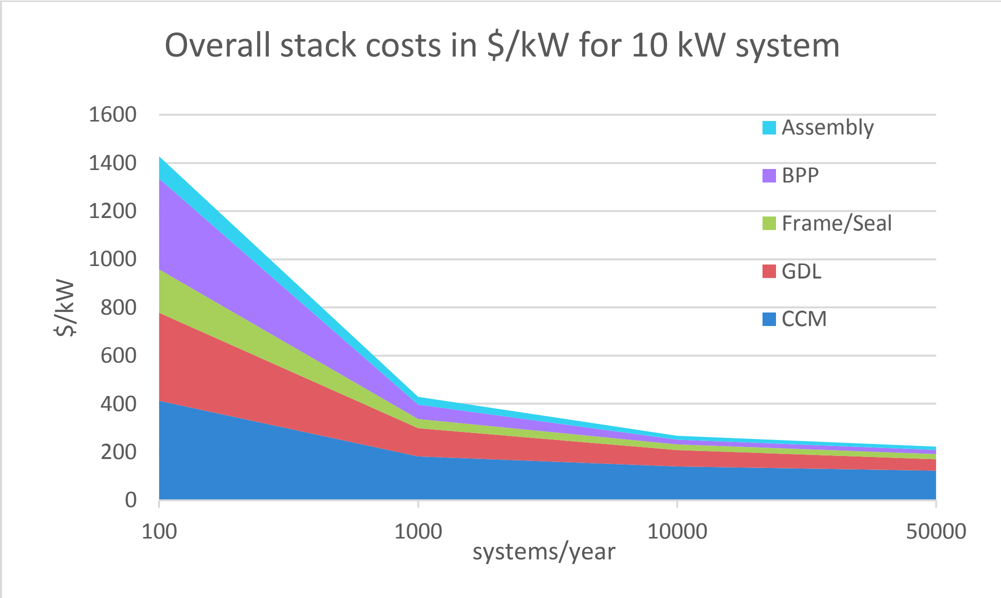


Figure 6-38 Breakdown of the stack cost in a stack components level for 10 kW system

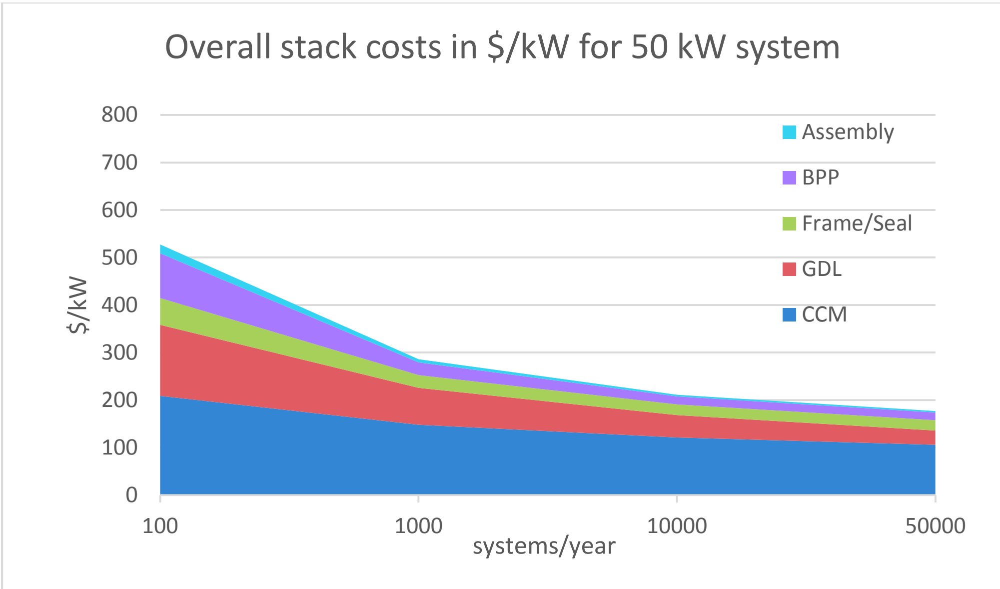


Figure 6-39 Breakdown of the stack cost in a stack components level for 50 kW system

The CCM remains almost constant at high production due to his Pt cost component. Metal plates, gas diffusion layers, frame and assembly costs decrease when annual volume kW increase. Assembly costs are negligible, compared to the overall costs, at high production rate. Disaggregation of stack cost by relative percentage of stack components costs to overall stack cost is provided in Figure 6-40 and Figure 6-41.

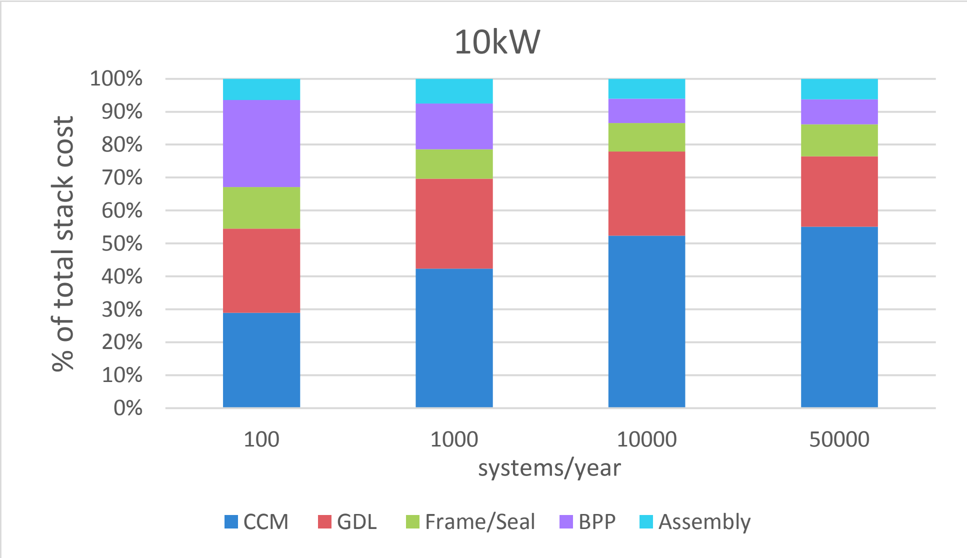


Figure 6-40 Percentage breakdown of stack components cost to overall stack cost for 10 kW system

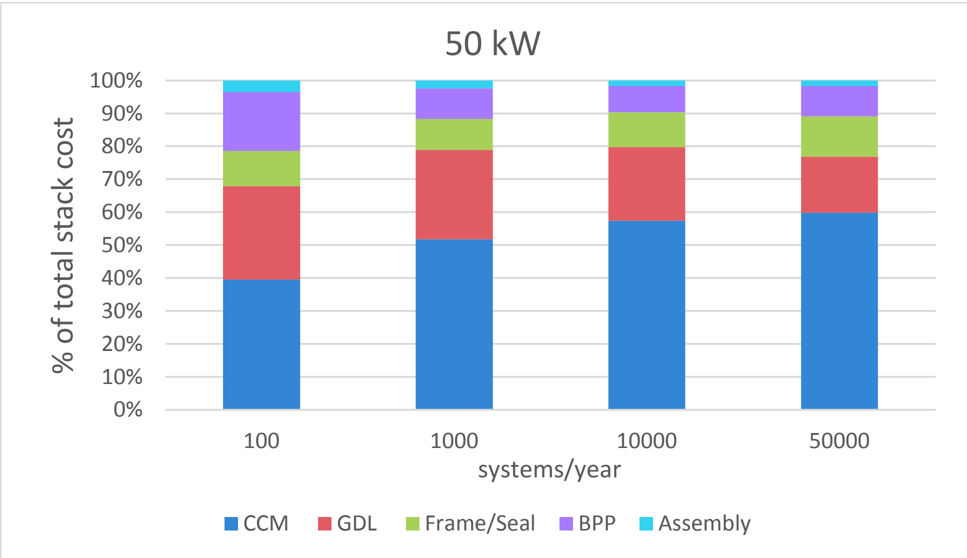


Figure 6-41 Percentage breakdown of stack components cost to overall stack cost for 50 kW system

Figure 6-40 and Figure 6-41 show that CCM constitutes the principal cost item with more than the half of the stack cost above an annual production of 500 MW (10,000 systems of 50 kW power). Interconnects, frame-seal, and gas diffusion layers each constitute about 10-20% of stack cost.

Metal plates percentage of cost decrease more with the increase of annual volume, compared to carbon plates, because the material cost, which is the constant component cost, is less expensive for metal bipolar plates. Assembly costs constitute from 2-5% of the overall cost.

6.9 Backup PEMFC system results

Backup PEM FC stack costs and balance of plant costs are integrated to provide the total system costs. Balance of plant results (Table 6-40) are taken from the LBNL 2014 report.

Table 6-40 Summary of BOP cost for backup systems

BOP cost for BU System with Direct Hydrogen ($/kW)	1 kW	10 kW	50 kW
100 units/year	3,597	653	345
1,000 units/year	2,852	518	271
10,000 units/year	2,235	403	208
50,000 units/year	2,008	366	188

Table 6-41 summarizes backup system costs for 1 kW, 10 kW and 50 kW systems at different production volumes.

Table 6-41 Summary of backup system direct costs

Backup System cost ($/kW)	1 kW	10 kW	50 kW
100 units/year	15,061	2,080	872
1,000 units/year	4,531	947	557
10,000 units/year	2,842	670	419
50,000 units/year	2,433	588	365

Detailed system cost plots as a function of manufacturing volume are presented in Figure 6-42 and Figure 6-43 for backup power system for the 10 kWe and 50 kWe system sizes.

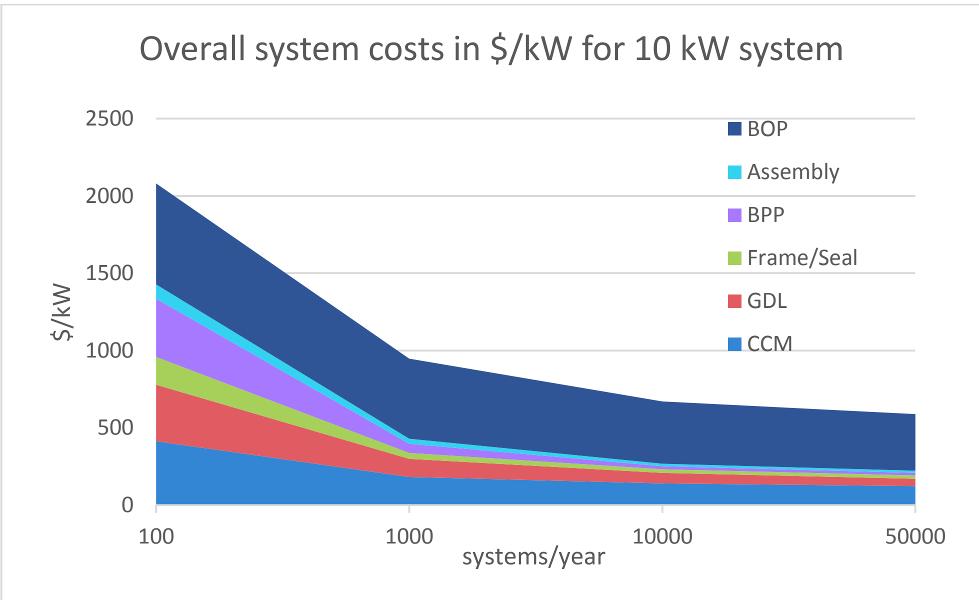


Figure 6-42 Overall system cost results for BU systems with direct hydrogen for 10 kW system

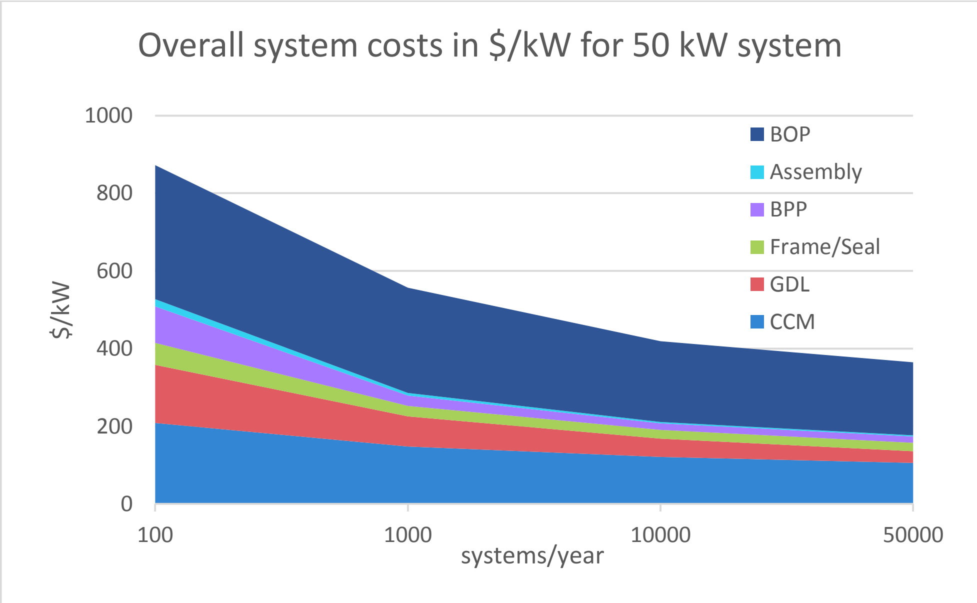


Figure 6-43 Overall system cost results for BU systems with direct hydrogen for 50 kW system

A percentage breakdown of overall system costs are shown in Figures 6-44 and Figure 6-45.

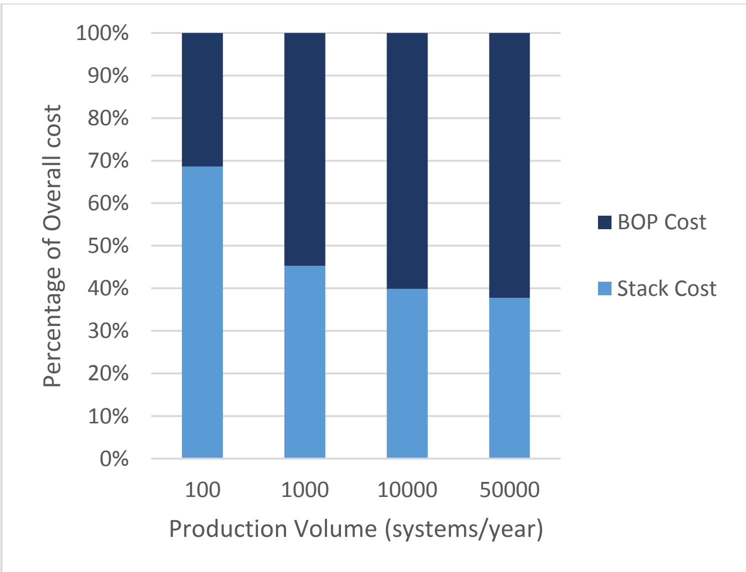


Figure 6-44 Percentage of overall system costs for BOP and fuel stack for 10 kW BU systems

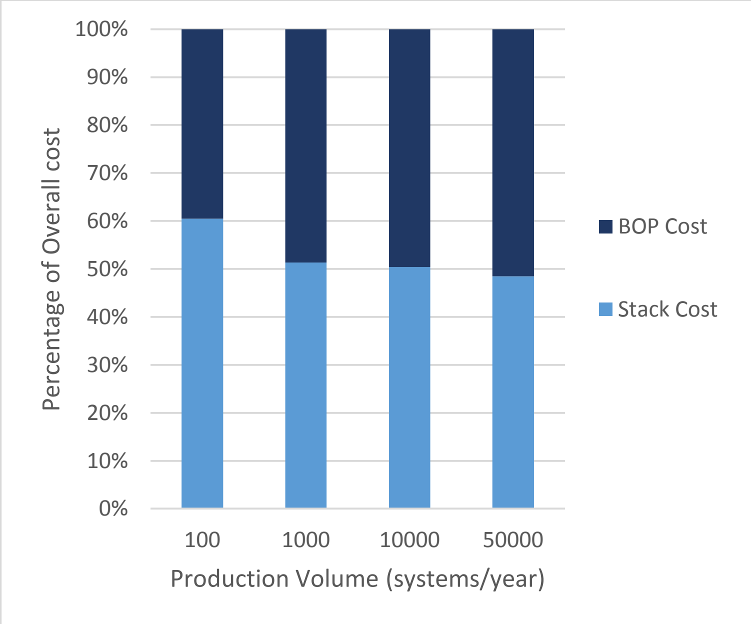


Figure 6-45 Percentage of overall system costs for BOP and fuel stack for 50 kW BU systems

BOP costs are lower relative fraction of system costs than the CHP case since the BOP is much simpler for the backup power system. At low production volumes the stack is a greater fraction of overall system cost and with increasing volumes, stack cost is between 40% and 50% of overall system cost.

Backup system installed costs are summarized in Table 6-42. As in reference [1], corporate markup is taken at 50% and an additional 25% markup is taken for installation and any additional fees. With these assumptions, installed cost for 10kW backup systems are estimated to be about $1800/kW at 1,000 units per year to about $1100/kW at high volume (50,000 units/year).

Table 6-42 Summary of backup system installed costs ($/kW)

Backup System cost ($/kW)	1 kW	10 kW	50 kW
100 units/year	28,239	3,900	1,635
1,000 units/year	8,496	1,776	1,044
10,000 units/year	5,329	1,256	786
50,000 units/year	4,562	1,103	684

6.10 Cost targets for backup power system

The purpose of this chapter is to compare the obtained modeled costs with actual costs.

6.10.1 NREL 2014 study

By December 2013, more than 1,300 fuel cell units were deployed with funding from the DOE ARRA program, of which 852 were providing backup service, mainly to telecommunications towers [30].

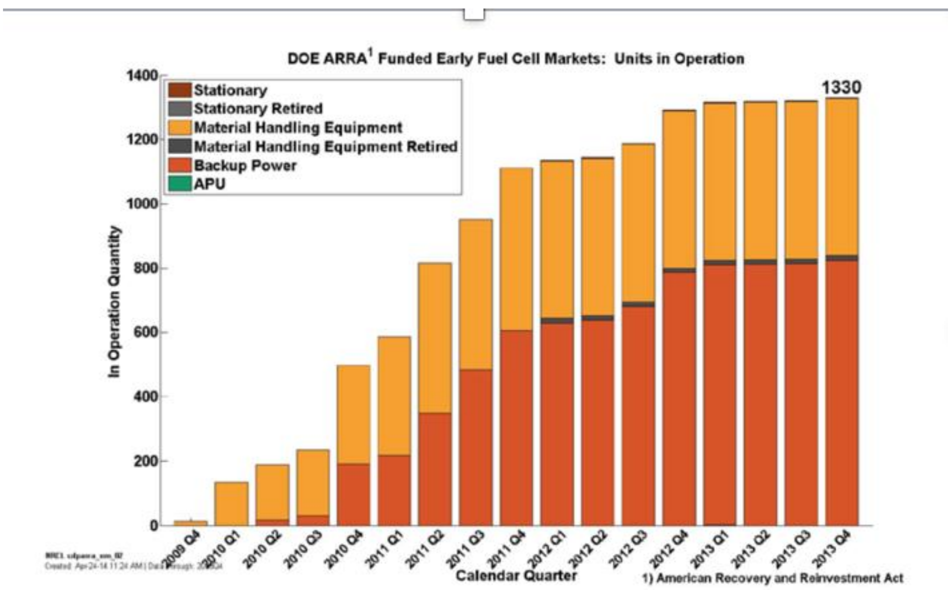


Figure 6-46 Fuel cell deployment from NREL [30]

While some system capacities were larger than 10 kilowatts (kW), 78% of the systems were in the 4-6 kW range [30].

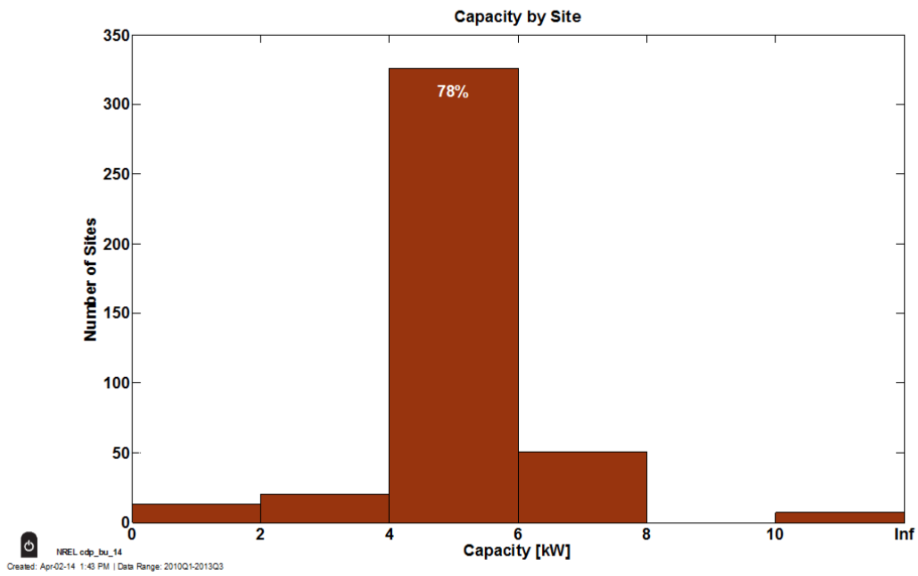


Figure 6-47 Percentage breakdown of fuel cell backup power system capacities from NREL [30]

Figure 6-48 shows the FC cost breakdown for different run time scenarios. All costs are presented as annualized costs per system in present value terms. Capital, permitting, and installation costs are amortized over the expected equipment lifetime (15 years).

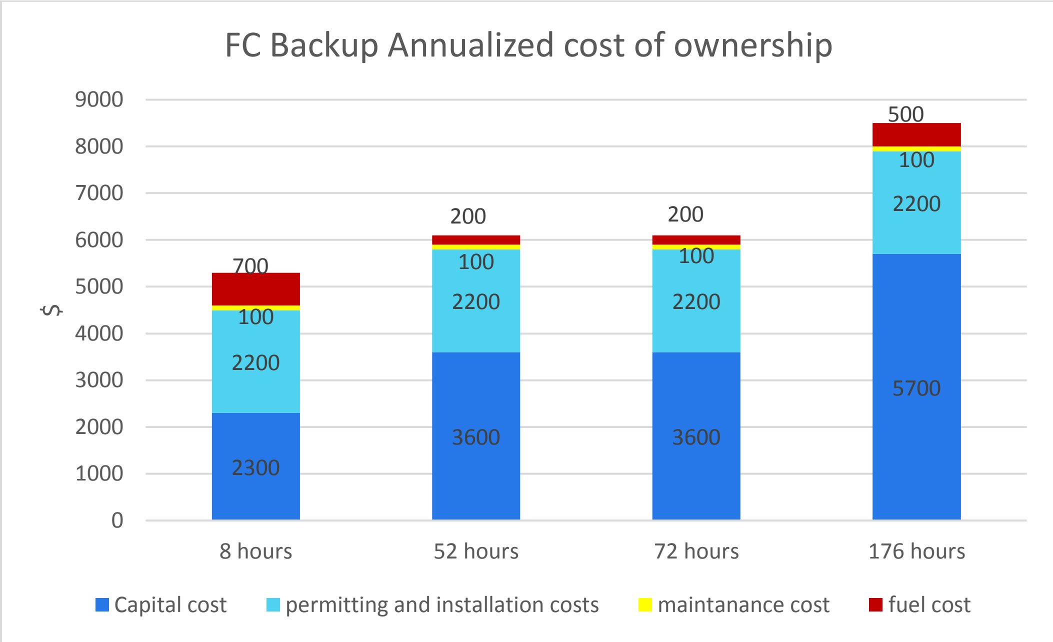


Figure 6-48 Backup FC cost breakdown for different run time scenarios from NREL

As can be noted in the graph, capital cost represents the major cost component, especially at the 176 hours run time scenario.

Table 6-43 5 kW FC Backup Power systems from NREL

Run time	**Capital cost**
8 hours	$30,700
52 hours	$47,600
72 hours	$47,600
176 hours	$76,000

There are two changes to the fuel cell system for different run time scenarios that affect the capital cost. The 8-hour scenario assumes the hydrogen storage unit is a pack of rented hydrogen gas bottles that are swapped out when the gas is low; the other three run time scenarios assume the fuel cell system has a hydrogen storage module (HSM) that is purchased and refilled in-place instead of using bottle swap-outs.

The 176-hour scenario increases the amount of on-site storage to 2.5 times that of the 72-hour scenario. Figure 6-49 shows a breakdown of the capital cost for the fuel cell system and HSM for the four run time scenarios. Note there is a small increase in the fuel cell cost for the 8-hour scenario, compared with the other run times. This is due to an enclosure for the hydrogen storage tanks.

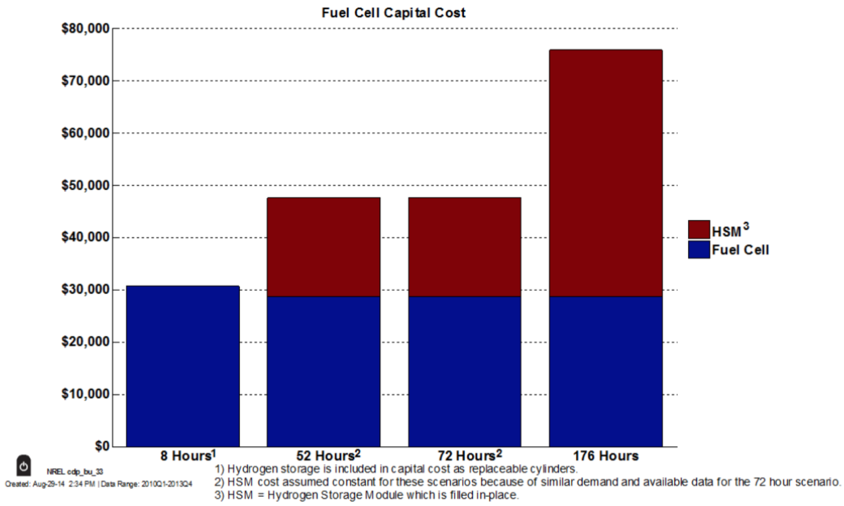


Figure 6-49 Breakdown of hydrogen storage and fuel cell capital costs from NREL

The cost difference between 52-hour and 72-hour run time scenarios is only in the cost of the hydrogen consumed and so it doesn't affect the capital cost.

The average capital cost in $/kW for a fuel cell system (without storage) is $5,700/kW [30]. Since NREL mainly considered backup systems in the range of 4-6 kW, a 5 kW cost model for a comparison of modeled costs to NREL's reported costs is performed.

6.10.2 5kW backup cost model

Table 6-43 summarize the functional parameters of a 5 kW fuel cell backup system.

Table 6-44 Functional parameters of a 5kW fuel cell backup system

5 kW		
Unique Properties:		**Units:**
Gross system power	5.20	kW
Net system power	5	kW (AC)
total plate area	360	cm^2
CCM coated area	306	cm^2
single cell active area	285	cm^2
gross cell inactive area	21	%
cell amps	116	A
current density	0.405	A/cm^2
reference voltage	0.650	V
power density	0.263	W/cm^2
single cell power	75.4	W
cells per stack	69	cells
percent active cells	100	%
stacks per system	1	stacks
Compressor/blower	0.025	kW
Other paras. loads	0.025	kW
Parasitic loss	0.05	kW

The above parameters are obtained by averaging the values of 1 kW and 10 kW of fuel cell backup system. A direct 5 kW cost model is obtained below using these functional specifications. The balance of plant costs are estimated using a log-log interpolation between 1 kW and 10 kW. Table 6-44 shows final cost results ($/kW) of all stack components.

Table 6-45 5 kW Backup power system cost components

	5 kW			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
CCM ($/kW)	649.7	212.8	151.4	130.2
BPP ($/kW)	745.7	94.8	27.1	19.8
Assembly ($/kW)	184.1	63.2	39.3	26.8
GDL ($/kW)	618.4	152.8	80.1	56.9
Frame-Seal ($/kW)	531.3	108.3	54.8	43.7
BOP ($/kW)	1,682.5	1,333.2	1,045.6	943.0
Total Capital Cost ($/kW)	4,411.7	1,965.1	1,398.3	1,220.4

6.10.3 Annual production volumes

The *DOE Hydrogen and Fuel Cells Program Record* provides, each year, the number of fuel cell deployments for applications in backup power. From this data, it is possible to build Table 6-45.

Table 6-46 Total number of backup power systems from DOE and Industry

	DOE and Industry Total backup systems From 2009 – June 2016
06/01/16	7833
04/29/15	6475
08/12/14	5023
09/05/13	4496

We consider the time interval from the 09/05/13 record until 06/01/16, to estimate the annual volume of backup systems as in Table 6-46.

Table 6-47 Average number of backup power systems per year

n of months	n of systems	n of systems/year
33	3337	1213

From its records, DOE takes into account 4 suppliers:

- Altergy
- Hydrogenics
- Ballard/IdaTech
- Plug Power/ReliOn

The annual number of FC backup systems per vendor is estimated to be about 300; breaking down the time intervals we can plot a graph of annual production over years (Figure 6-50). Finally we assume that about 80% of these units are 5 kW units as in Figure 6-47 for an average annual production volume of about 240 units per vendor per year.

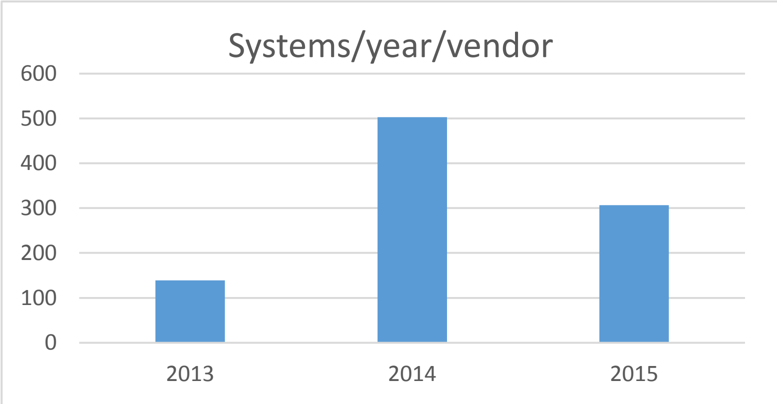


Figure 6-50 Backup power systems per vendor over years 2013-15

6.10.4 Cost comparison with reported prices

Table 6-47 presents the results of the capital cost ($/kW) comparison between NREL and our direct analysis of 5 kW backup system. Different markup values (25%, 50%, and 75%) are applied to the NREL capital price. We assume an average of 240 units per year annual volume in this time frame, with a lower value case of 100 units per year as in Figure 6-50. For a nominal markup of 50%, the LBNL modeled result of $3909-4412/kW is within 3% to 16% of the reported cost. However, this comparison is necessarily rough, since there are multiple uncertainties in the corporate markups, annual volumes, actual mix of stack costs vs. BOP costs, and make-vs. buy decisions. For example, at these low volumes, there are uncertainties in the stack costs since on the one hand, vendors may rely on purchased parts which themselves may have high markups; conversely, if they are building stack parts themselves, capital costs are expected to be high since as we have seen above, process equipment will usually have low utilization.

Table 6-48 Estimated direct cost difference for reported backup power systems vs. LBNL modeled cost

5kW reported price ($/kW) NREL [30]	Assumed Markup	5 kW direct cost ($/kW) vs mark-up	LBNL 5 kW direct cost ($/kW) 100 units/yr	LBNL 5 kW direct cost ($/kW) 240 units/yr	Difference (%)
5700	25%	4560	4412	3909	-3% to -14.3%
5700	50%	3800	4412	3909	16% to 2.9%
5700	75%	3257	4412	3909	35% to 20%

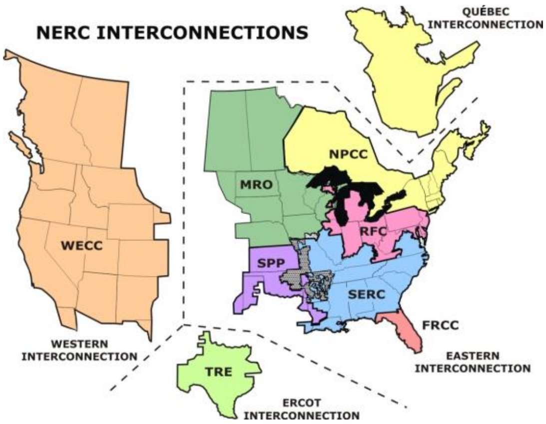
7 Life Cycle Impact Assessment

This work updates the life cycle impact assessment (LCIA) model. Detailed discussion of the background approach is found in Wei et al, 2014 and is not repeated here. There are several phases of updates here: (1) updated regional emissions factors for CO_2 and criteria pollutant emission rates; (2) updated marginal benefits of abatement valuation from the APEEP to the AP2 (APEEP2) [31] model; and (3) updated approximate emission factors in the 2025-2030 timeframe based on current and proposed EPA and national regulations.

Life-cycle or use-phase modeling and life cycle impact assessment (LCIA) was carried out for regions in the U.S. with high-carbon intensity electricity from the grid (Midwest and upper Midwest U.S.). In other regions, TCO costs of fuel cell CHP systems relative to grid power exceed prevailing commercial power rates at the system sizes and production volumes studied here.

7.1 Regional emissions factors for CO_2 and criteria pollutant emission rates

Previous analysis used marginal emission factors by NERC region. This work uses eGRID 2012[3] sub-regional emission rates for improved spatial resolution. Figure 7-1 has a comparison of CO_2 emission factors by NERC region per Siler Evans et al. (2012) [32], and eGRID sub regional non-baseload output emission rates. Note that there is more than a factor of two difference in emission rates across sub regions. Emission rates comparisons for eGRID vs NERC are shown in Figure 7-2. For each pair of bars, the first bar is the larger NERC region (old value) and the second bar is the eGRID sub region (updated value). There is reasonable agreement across regions except that SOx are much lower in NYC perhaps due to more natural gas build out, and SOX is much higher in Texas (ERCOT).



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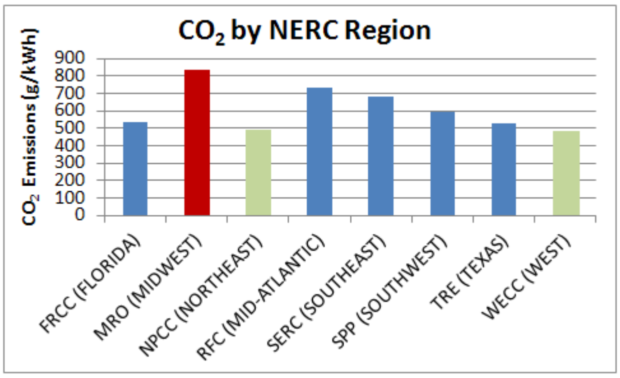
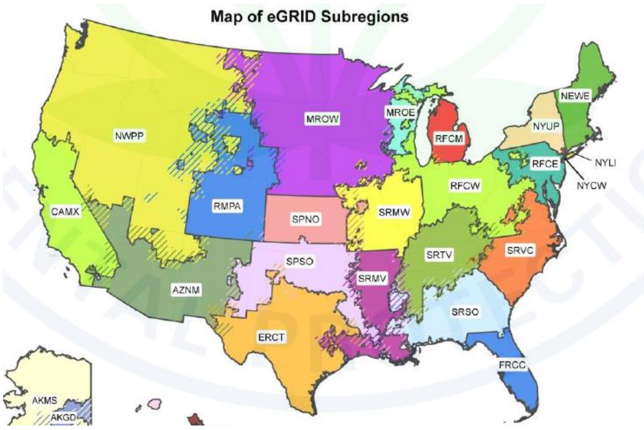


(b)

[3] Available at https://www.epa.gov/sites/production/files/2015-10/documents/egrid2012_summarytables_0.pdf, accessed 15 March 2016.



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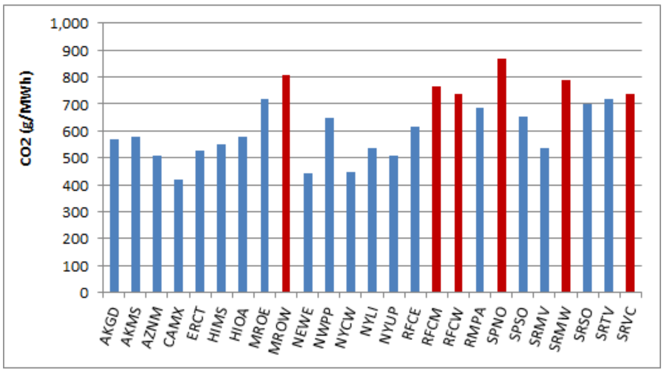
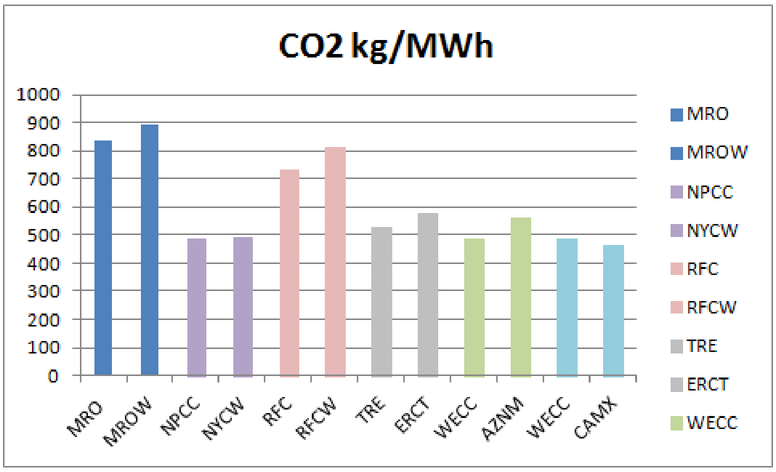


(d)

Figure 7-1. (a) NERC sub regions; (b) NERC marginal emissions factors; (c) eGRID sub regions; (d) eGRID non-baseload output emission rates.

(a)



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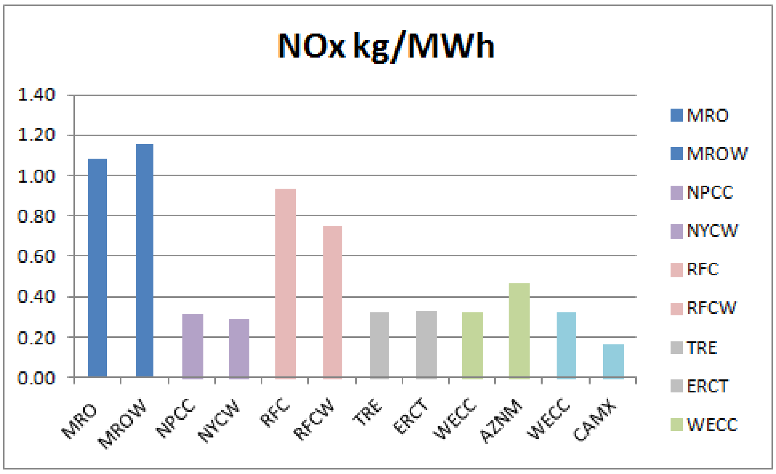

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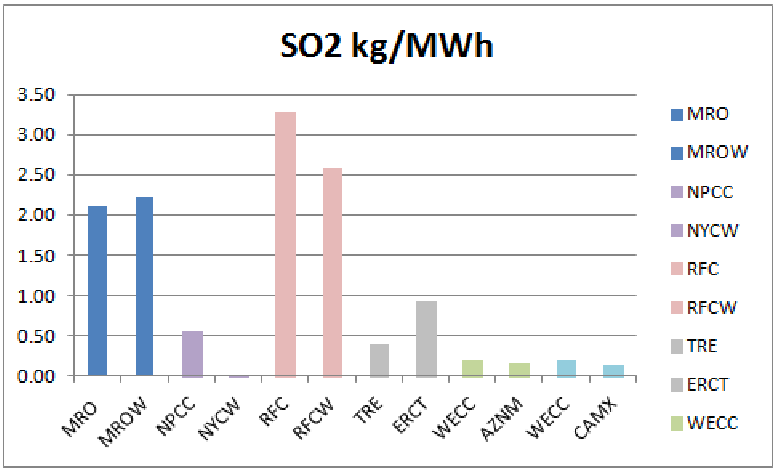


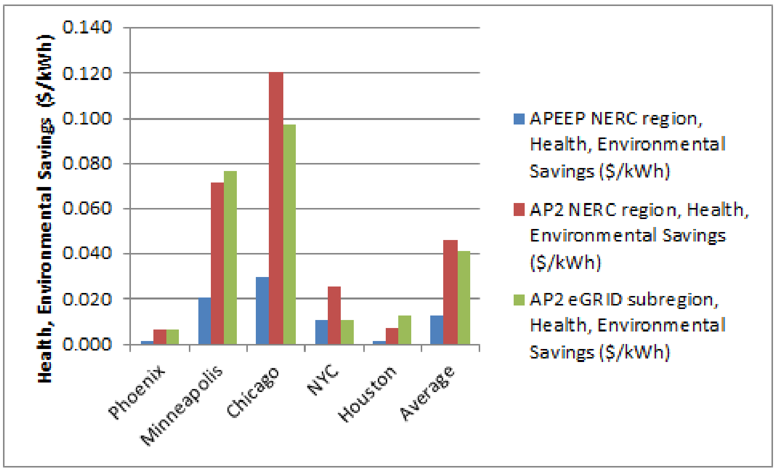
Figure 7-2. Emission rates for eGRID sub regions vs NERC-level marginal emission rates.

7.2 Updated marginal benefits of abatement valuation

The second change to the LCIA model is to update the marginal benefits of abatement for each city to the updated AP2 (APEEP2) value from the APEEP values utilized before. This is shown for the case of a 50 kW small hotel CHP system in Figure 7-3 below. Figure 7-3a shows the product of pollutant quantity per ton and the human health and environment damage factors in dollars/ton given by AP2 by region. The first bar has old values of marginal emission factors and APEEP damage factor. The second and third bars utilize NERC region and eGRID sub regional damage factors, respectively, together with updated AP2 damage factors Overall damage factors in dollars per ton for AP2 are generally three- to five-times higher than APEEP and thus the increase from the first to second bars are large. Figure 7-3b shows the total externality valuation in $/kWhe of fuel cell electricity which include the the health and environment damage factors and GHG emission credits at $40/ ton CO2 societal cost of carbon. Overall externality benefits are similar in moving from NERC to eGRID emission factors but are lower in NYC and higher in Houston as noted above. Note that in other studies (e.g. Wiser et al. 2016 [33), AP2 damage factors yield estimates that are on the low end of health and environmental benefits from air emissions reductions compared to other EPA models.

A detailed accounting for the large increase in AP2 damage factors over APEEP is beyond the scope of discussion, but we mention several contributing factors (Muller 2016, pers. communication): (1) There are more years and more recent years represented in AP2. Marginal damages produced for each pollutant differ by year (1999, 2002, 2005, 2008, and 2011). APEEP only has 1999, 2002, but AP2 includes values for 2011; (2) For primary PM2.5, damages basically increase proportionally to population; (3) For NOx, NH3, and SO2, damages depend on the relative mix of these in the atmosphere which has changed and been updated between 1999 and 2011; (4) AP2 has been calibrated to ambient monitoring data for PM25 and O3 which also changes the marginal damages; (5) AP2 uses a more refined baseline mortality rate data (in terms of attribution of rates to different age classes); (6) AP2 uses a dose-response function for chronic bronchitis effects from PM2.5 rather than PM10 which was used in APEEP. This also increases the damage estimates.

(a)



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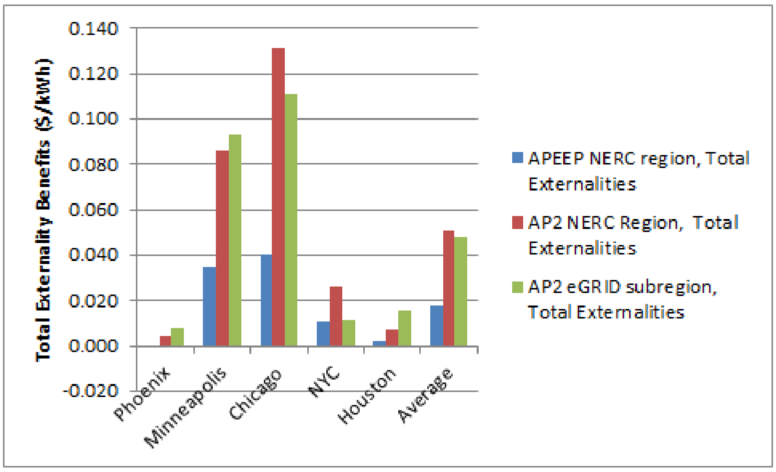


Figure 7-3 Updated marginal benefits of abatement valuation from APEEP model to AP2 model and updated from NERC to eGRID sub region emission factors

7.3 Estimating a cleaner grid in 2030

For comparisons of a fuel cell CHP and grid electricity, it is important to include the impact of a cleaner grid over time with state and national policies such as state renewable portfolio standards and the EPA Clean Power Plan (CPP). For example, the CPP improves emissions from coal plants and shifts from coal to natural gas, and may build more renewable sources of electricity such as wind and solar. The advantages of lower emissions from fuel cell systems are thus reduced over time under these assumptions, and a key question is the following: how will these changes impact the externality benefits of fuel cell CHP?

Average reductions in average emission factors for CPP and other regulations for NOx and SOx are shown in Table 7-1 below. A 13% average reduction in CO_2 average emission factor is projected from 2012 to 2030, and about 80% average reduction in SO_2 tons/kWh from 2012-2025 and about 50% average reduction in NOx tons/kWh from 2012 to 2025.

Electricity demands are taken from the AEO2015 base case for 2015-2025 and extrapolated to 2030, and a nominal 7% demand reduction from energy efficiency is assumed in 2030 from the Clean Power Plan in all regions. CO_2 reductions are taken from mass based reduction targets in Clean Power Plan. The change in NYC is small and actually increases because CO_2 tonnage is down by a single digit percentage and demand is lower, so that the change in emissions per MWh is slightly higher. Note that the regulations for CO_2 emissions and SO2, Nox are not the same. The Clean Power plan regulates CO_2 and this impacts SO_2, NO_X; but SO_2 and NO_x have existing regulations with a base emissions reduction in tonnes of 70% and 25%, respectively in 2025 from 2012 (e.g. Mercury and Air Toxics Standards (MATS)).

Table 7-1 Estimated Clean Power Plan and other regulatory impacts for six representative regions

City	EGRID subregion	EGRID for 2012, kg/MWh			2030 Projection with Clean Power Plan, kg/MWh			% Reduction 2030 from 2012		
		CO2 AEF eGRID	SO2 AEF eGRID	NOx AEF eGRID	CO2 AEF	SO2 AEF	NOx AEF	CO2	SO2	NOx
Minneap.	MROW	646	1.33	0.73	489	0.25	0.45	24%	81%	38%
NYC	NYCW	316	0.03	0.15	322	0.00	0.05	-2%	97%	64%
Chicago	RFCW	626	1.54	0.55	510	0.40	0.34	19%	74%	37%
Houston	ERCT	518	0.87	0.28	440	0.09	0.11	15%	90%	61%
Phoenix	AZNM	523	0.20	0.59	459	0.07	0.30	12%	64%	50%
S. Diego	CAMX	295	0.09	0.15	259	0.03	0.08	12%	62%	46%
Average								**13%**	**78%**	**49%**

7.4 LCIA for the 2016-2030 time period

The 2014 report presented a single year of life-cycle costs for a fuel cell CHP system installed in six cities across the U.S in Table 7-1. It was found that fuel cell systems were favorable in certain niche applications in certain regions of the country, for example, in small hotels in the Midwest and upper Midwest. In this report, we present the cash flows for fuel cell systems for a fifteen year period of 2016-2030 for two cases: (a) for a static electricity grid and (b) for a grid that is getting cleaner per Table 7-1. We focus on Minneapolis and Chicago since those were favorable cases in the previous report and here we investigate whether those benefits persist even with a cleaner grid. Note that even with the higher externality valuations as in Figure 7-3b, the other cities (Phoenix, New York, and Houston) are still not competitive with the grid at the FCS prices assumed above.

In all cases, an escalating social cost of carbon starting from a \$40/ton value in 2016 and increasing to \$56 in 2030 per Table 7-2 is assumed (from the Clean Power Plan Regulatory Impact Analysis, Oct. 2015) which assumes a 3% discount rate value for 2015, 2025, 2030.

Table 7-2 Social cost of CO_2, 2015-2050 (2014\$ per tonne)

Disc. Rate=>	**5% avg**	**3% avg**	**2.5% avg**	**3% (95th %-tile)**
2015	\$13	**\$41**	\$63	\$116
2020	\$14	\$46	\$70	\$139
2025	\$15	\$51	\$75	\$151
2030	\$17	**\$56**	\$81	\$174

2035	$20	$61	$87	$186
2040	$23	$67	$94	$209
2045	$26	$72	$100	$220
2050	$29	$77	$106	$232

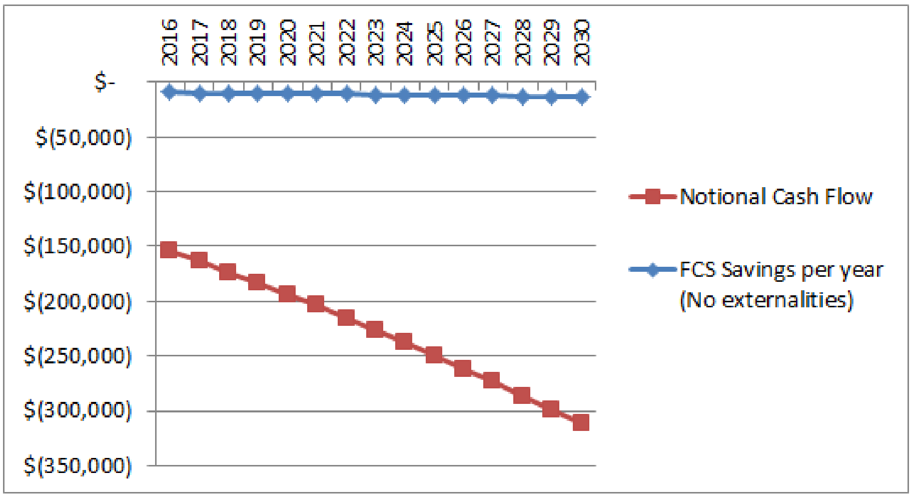
7.5 LT PEM CHP in small hotels in Chicago and Minneapolis, 2016-2030

We examine first a 50 kW CHP system in a small hotel in Chicago. An installed cost of $2900/kWe is assumed, commensurate with a high volume case of about 100 MWe annual production. For all cases, we assume AEO2015 baseline values for natural gas and electricity prices and annual increases of 1.6% and 0.6%, respectively for the price of natural gas and electricity.

Case 1. Static emission factors.
In Figure 7-4a, the FCS vs Grid case is shown for the case of no externalities and static grid emission factors. The FCS is more expensive each year of operation and the cash flow is negative and more negative across the fifteen year lifetime. In the case of including externalities (Fig. 7-4b), the FCS realizes about $29,000 savings per year on a societal basis and the cash flow becomes net positive after about 4 years of operation. The net present value of the FCS on a societal basis is zero at a fuel cell capital cost of $5700/kWe. Note that Figure 7-4b is not a real cash flow, but is one that would be realized if all private costs and public benefits accrued to the owner of the FCS.

Case 2. Decreasing emission factors.
Again we consider the case of a 50 kW fuel cell CHP system installed in a small hotel in Chicago from 2016-2030, but this time with a reduction in grid emission factors tracking the estimated reduction in average emission factors assumed in Table 7-1. Here the reduction in grid emission factors correspond to a reduction in the total cost of ownership savings and a "bending over" of the cash flow in later years. The cash flow is seen to reduce from $250,000 in 2030 to about $100,000 (Figure 7-4c). The net present value of the FCS on a societal basis is zero at a fuel cell capital cost of $3850/kWe. Figure 7-4b and 7-4c are "bounding cases" for this building case in the sense that the first figure represents a static grid (at least in terms of marginal emission factors) and the second figure represents the case that MEFs change to the full degree as the average emission factors in Table 7-1. Figures 7-5 to 7-7 show other small hotel cases in Chicago and Minneapolis for 10 kW and 50 kW fuel cell systems. In all cases where externalities are valued, the cash flow on a societal basis is net positive in 2030.

(a)



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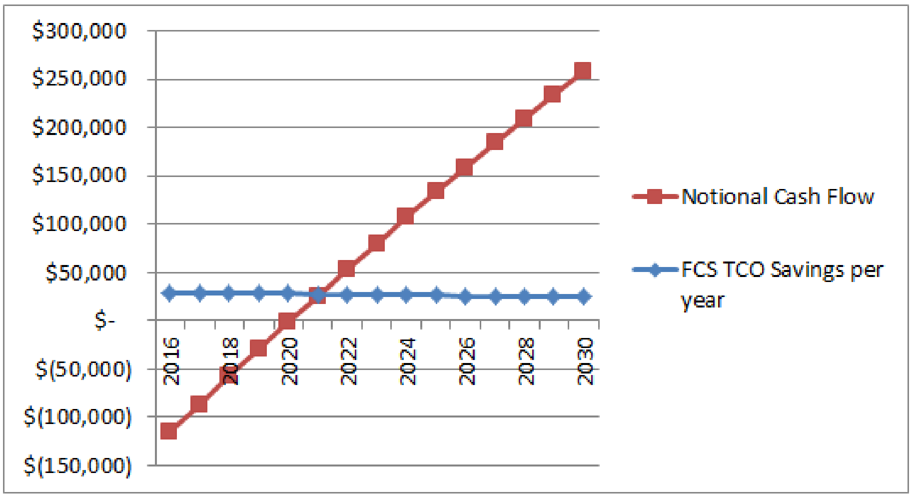

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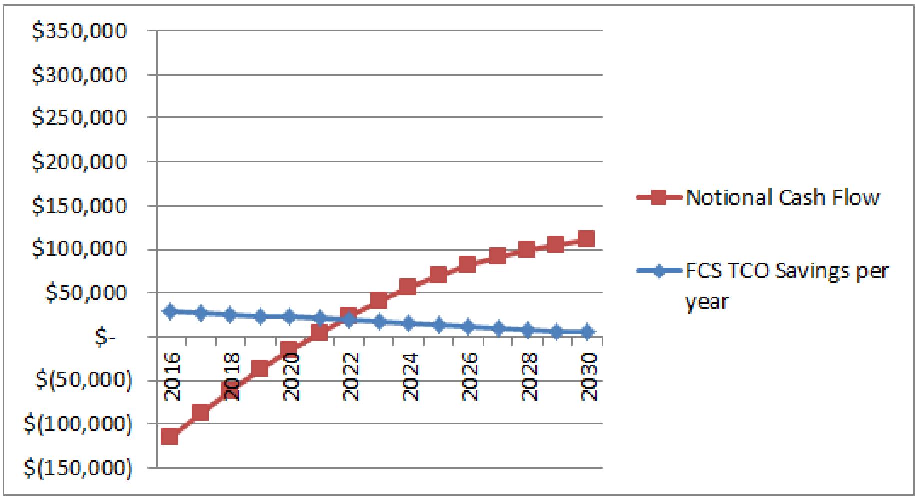
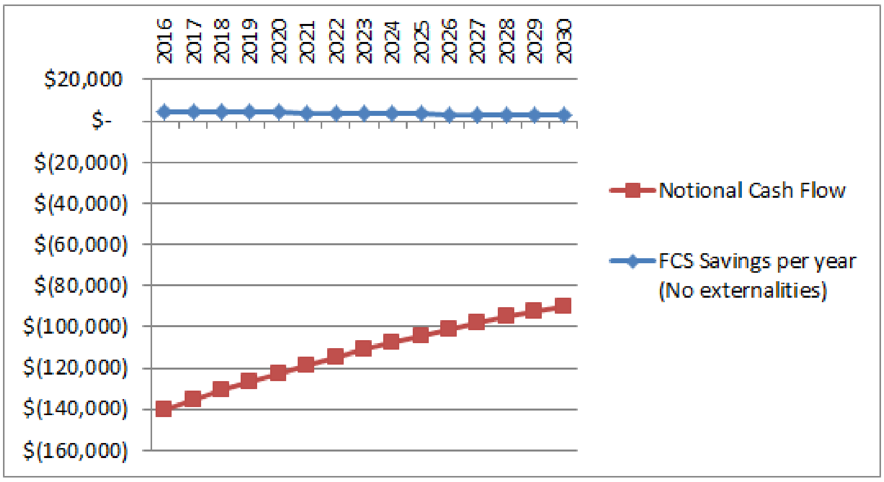


Figure 7-4. Notional cash flow for the case of a 50 kW fuel cell CHP system for a small hotel in Chicago with (a) no externality valuation; (b) externality valuation with fixed marginal emission factors and (c) with externality valuation and lower grid emission factors.

(a)



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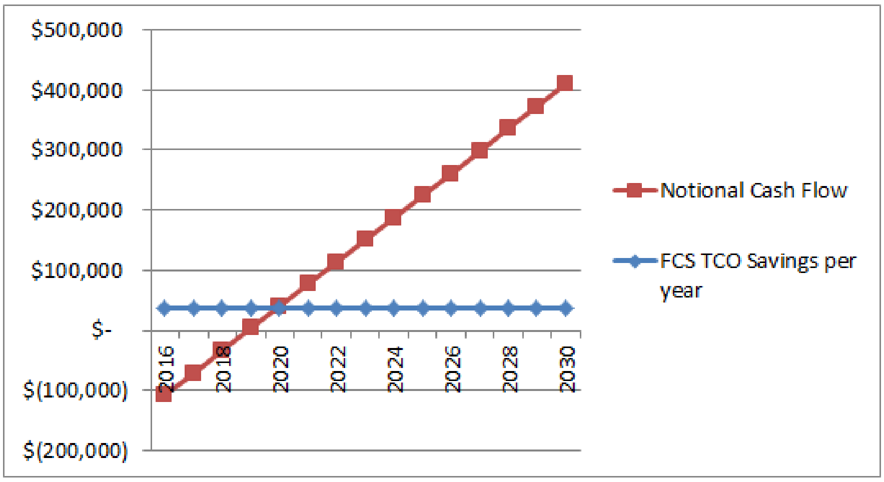

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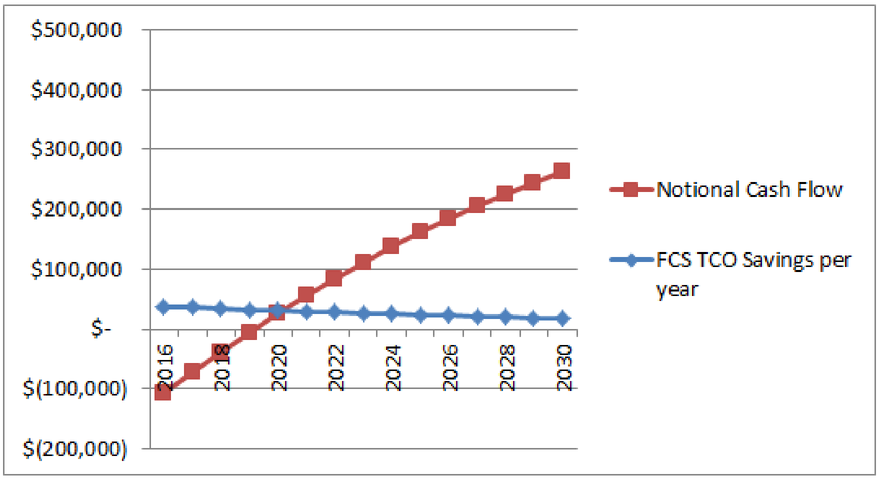

Figure 7-5 Notional cash flow for the case of a 50 kW fuel cell CHP system for a small hotel in Minneapolis with (a) no externality valuation; (b) externality valuation with fixed marginal emission factors and (c) with externality valuation and lower grid emission factors.

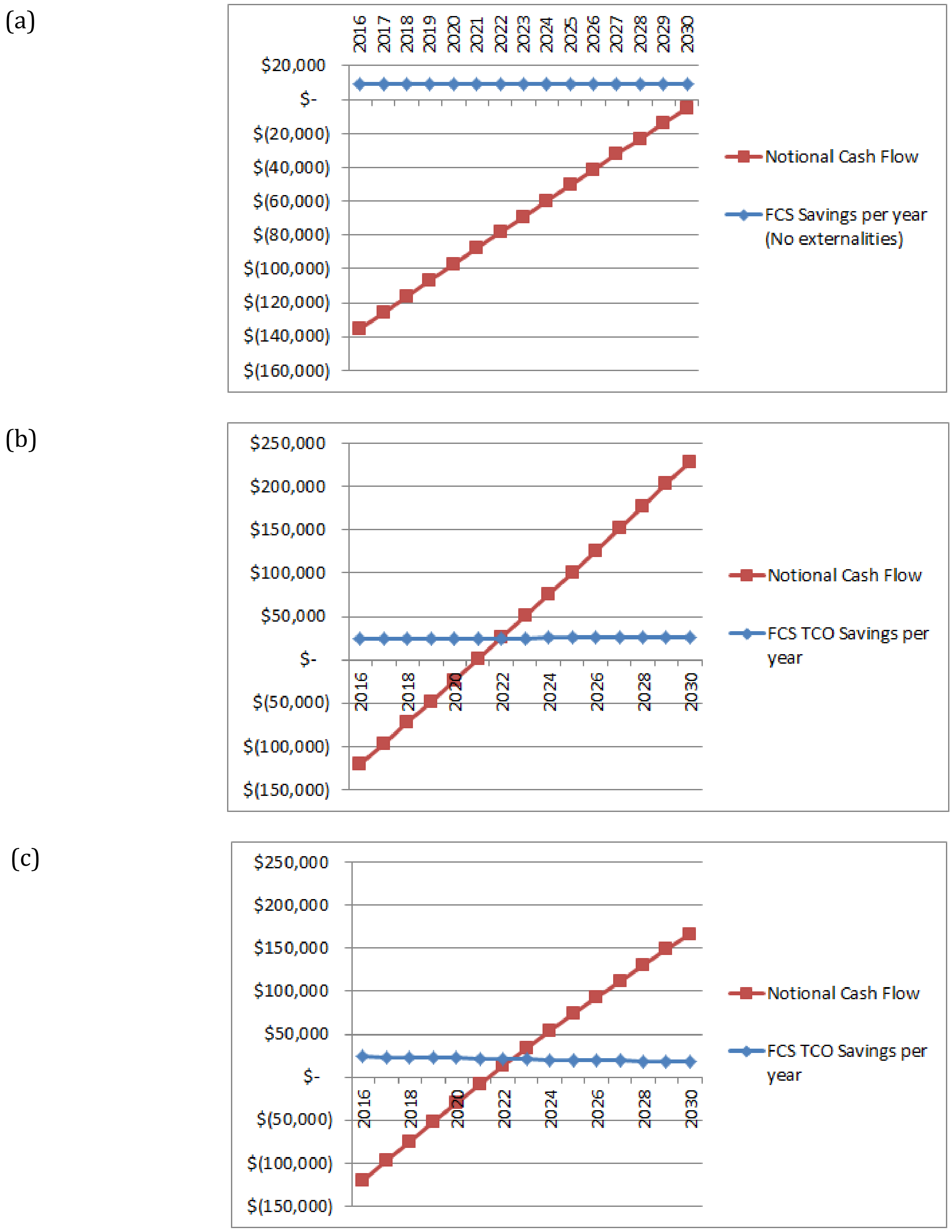

Figure 7-6 Notional cash flow for the case of a 10 kW fuel cell CHP system for a small hotel in Chicago with (a) no externality valuation; (b) externality valuation with fixed marginal emission factors and (c) with externality valuation and lower grid emission factors.

(a)

(b)

(c)

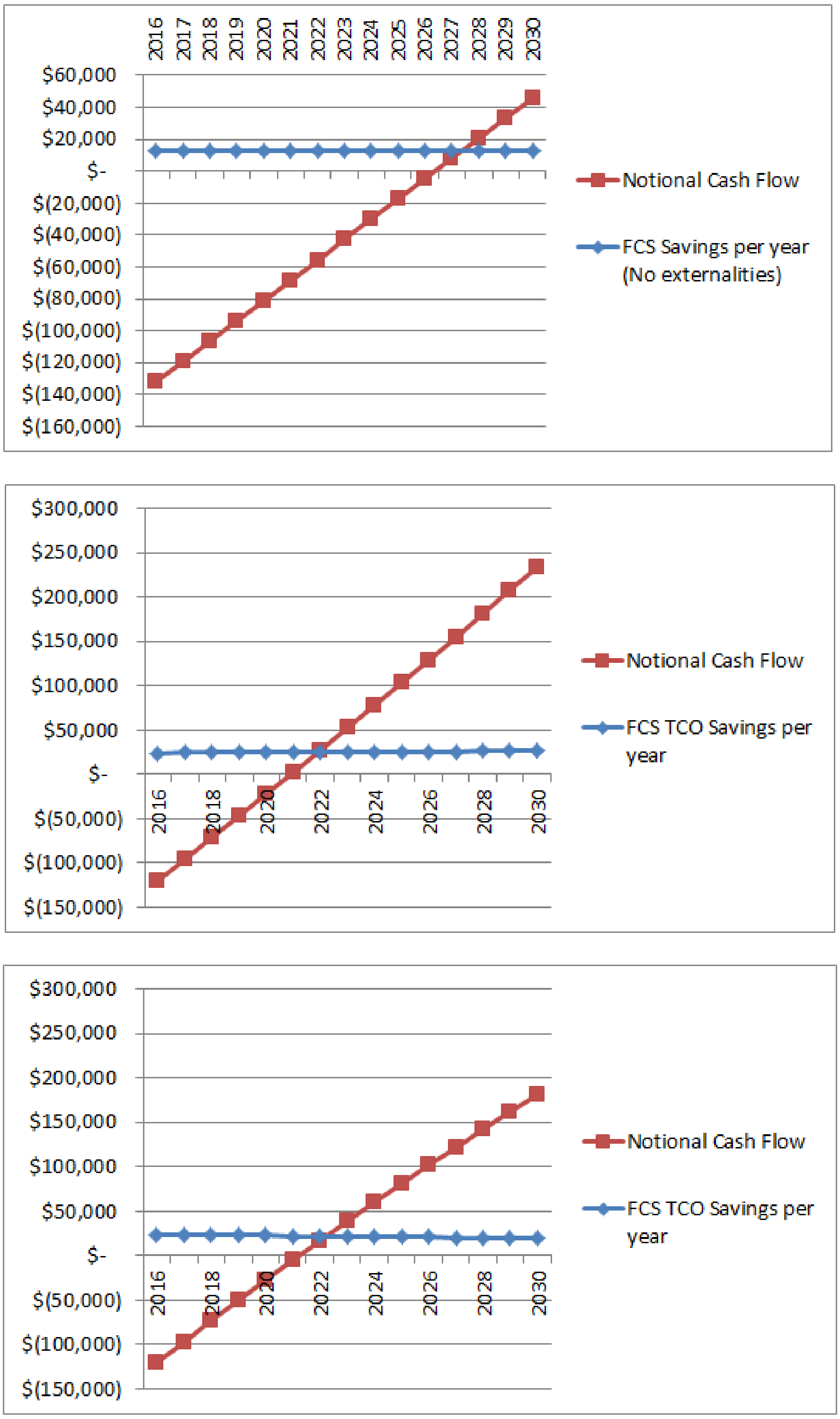

Figure 7-7 Notional cash flow for the case of a 10 kW fuel cell CHP system for a small hotel in Minneapolis with (a) no valuation; (b) externality valuation with fixed marginal emission factors and (c) with externality valuation and lower grid emission factors

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8 Appendix: CCM Cost Comparison to 2014 LBNL report

To understand which cost components most affect the CCM overall cost, manufacturing costs, over annual production volume (MW/year) are analyzed individually.

Material costs

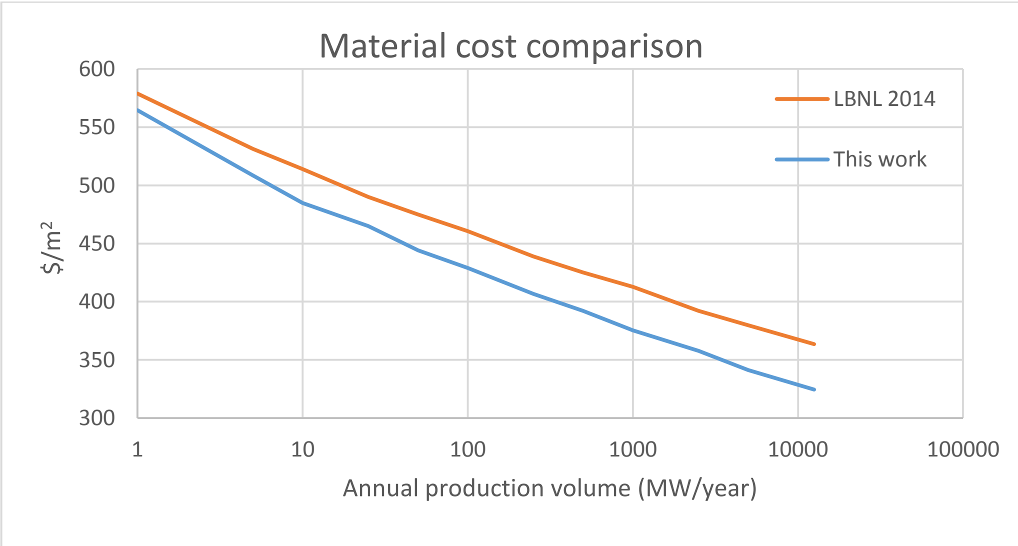

Figure 8-1 Material cost comparison

The material costs obtained in this work are lower than LBNL analysis at all annual production volumes.

Figures 8-2, 8-3 and 8-4 show the comparisons of process yields, Nafion® membrane costs and platinum costs, which are the principal components of the material cost.

Process yield

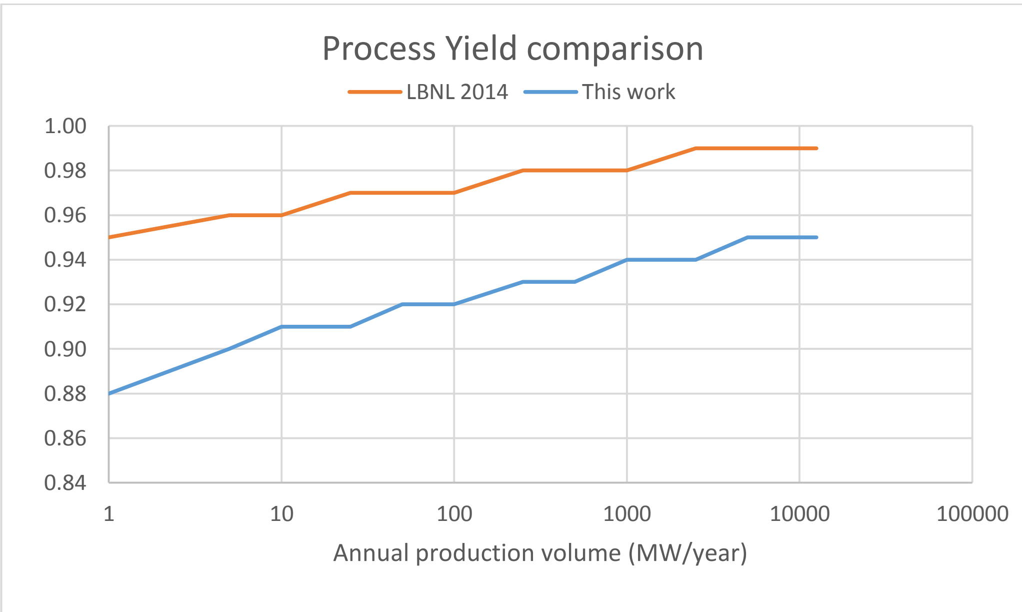

Figure 8-2 Process yield comparison

Lower process yields for all annual production volumes are assumed.

Nafion® membrane

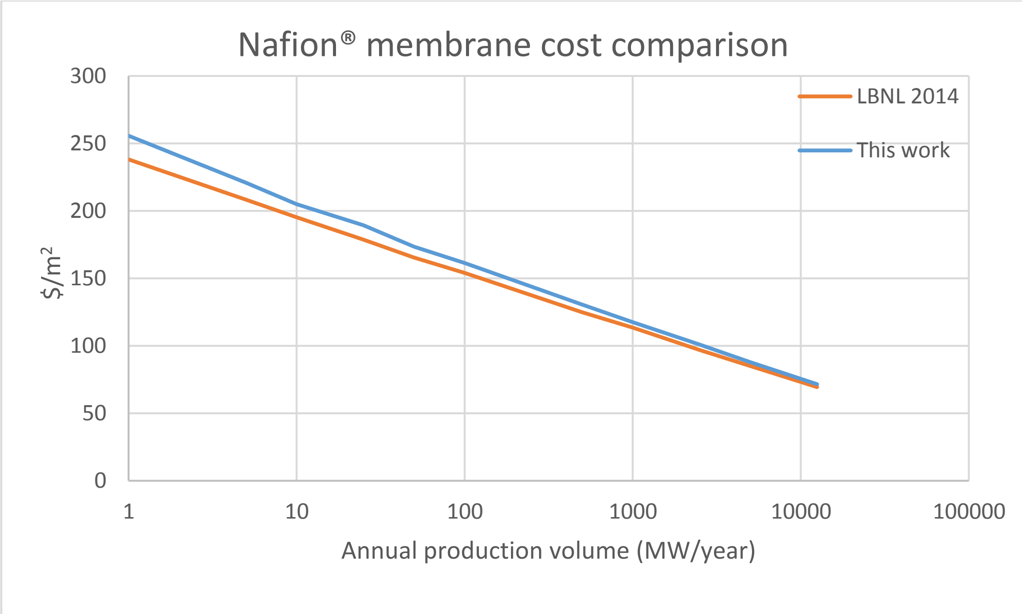

Figure 8-3 Nafion® membrane cost comparison

Higher Nafion® membrane cost results for this work are due to lower process yields assumed.

Platinum

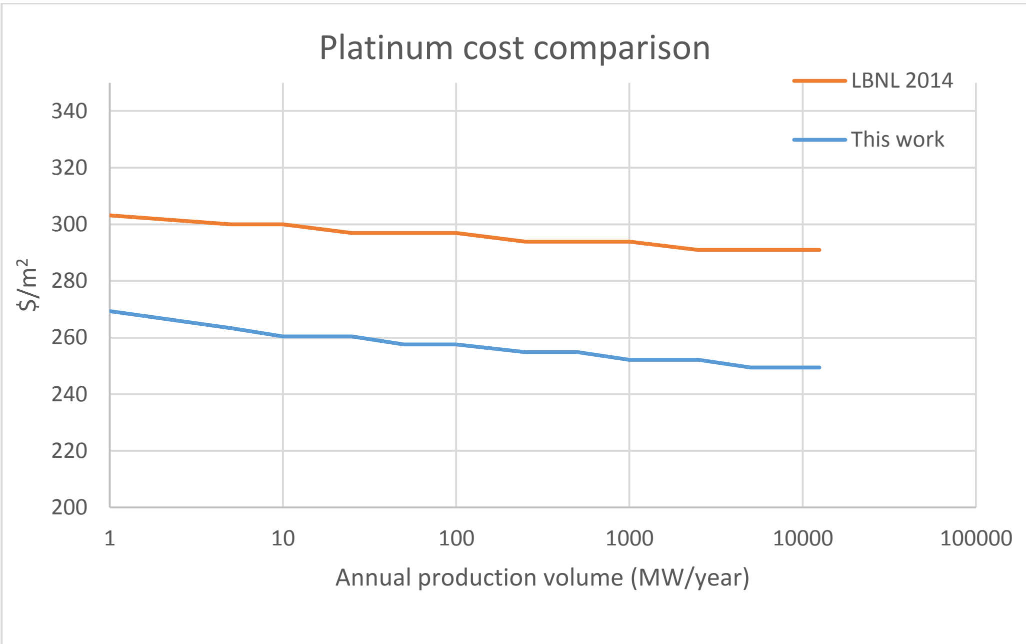

Figure 8-4 Platinum cost comparison

Platinum cost results are lower than LBNL report due a lower Pt price assumed here (from \$57.6/g to \$47.4/g). Even though lower process yields are assumed, total material costs are lower because the platinum price lowering.

Labor costs

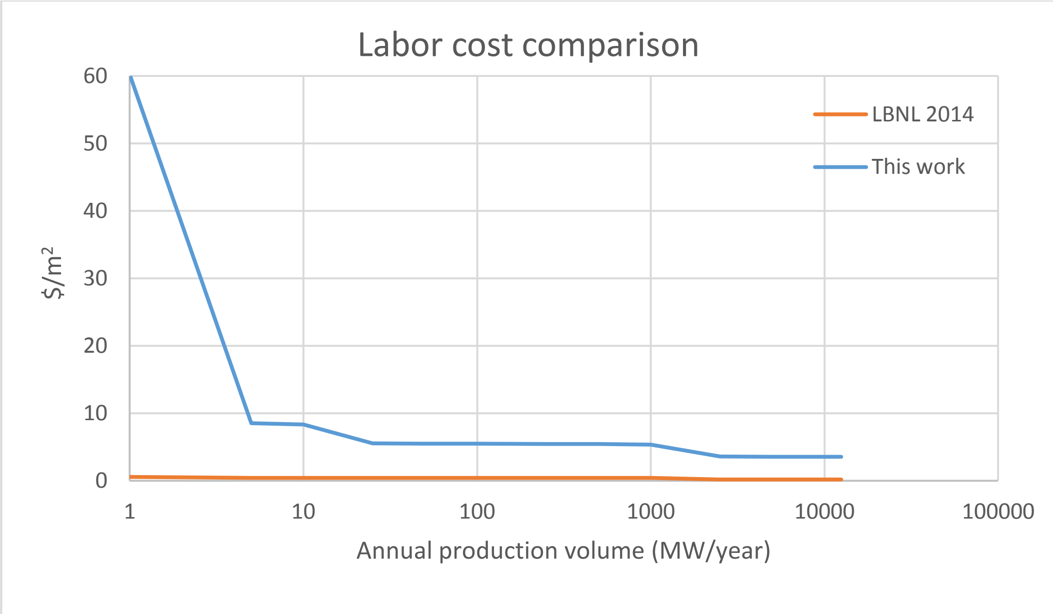

Figure 8-5 Labor cost comparison

New labor costs are higher for various reasons:

- lower line speed that increases the annual operation hours
- Presence of workers for mixing/pumping and quality unit processes
- Different worker rate assumption at 1MW annual production volume: a total labor cost equal to the 25% of engineering annual salary is assumed.

Process: Capital costs

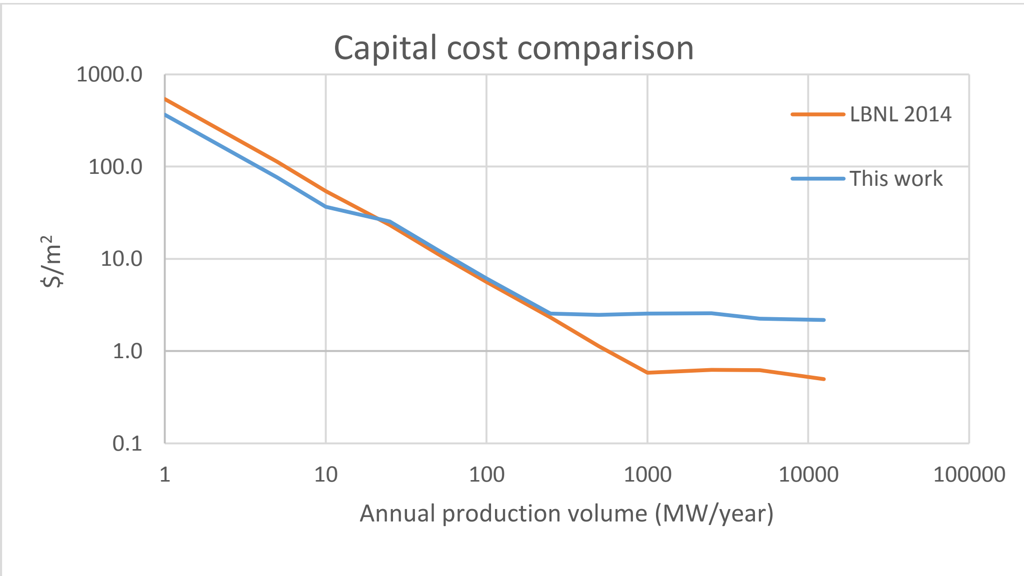

Figure 8-6 Capital cost comparison

- Annual production volume < 500 MW: new results are lower than LBNL results due to lower discount rate and average inflation rate.
- Annual production volume > 500 MW: lower line speed increases number of lines and consequently the number of machines purchased.

Process: Operational costs

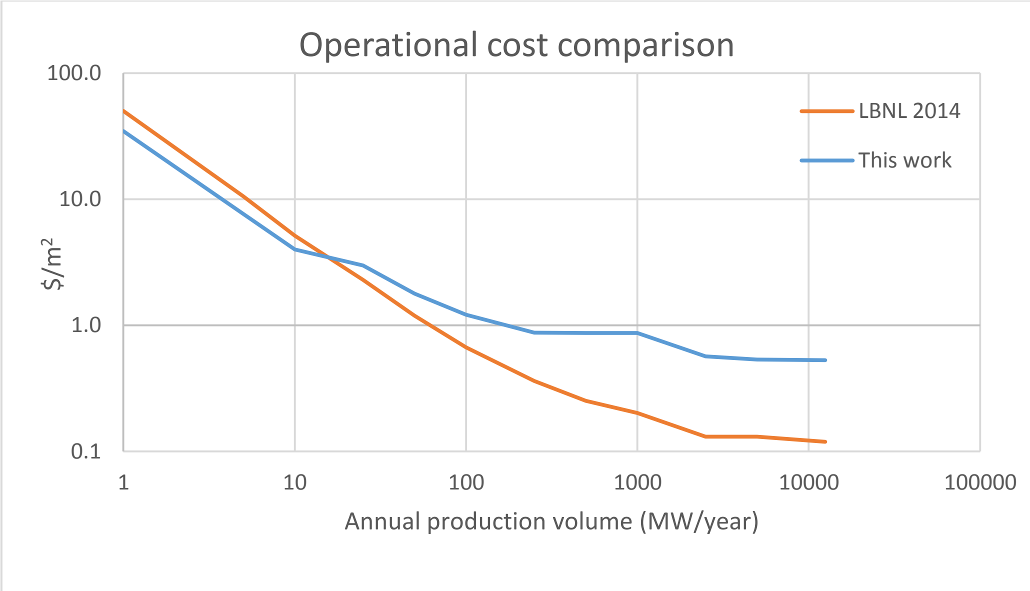

Figure 8-7 Operational cost comparison

- At low production volume new operational costs are lower than LBNL costs because maintenance costs are smaller, as consequence of lower interest indexes.
- At high production volume new operational costs are higher than LBNL costs because energy costs are greater, as consequence of increased annual operation hours.

Process: Building costs

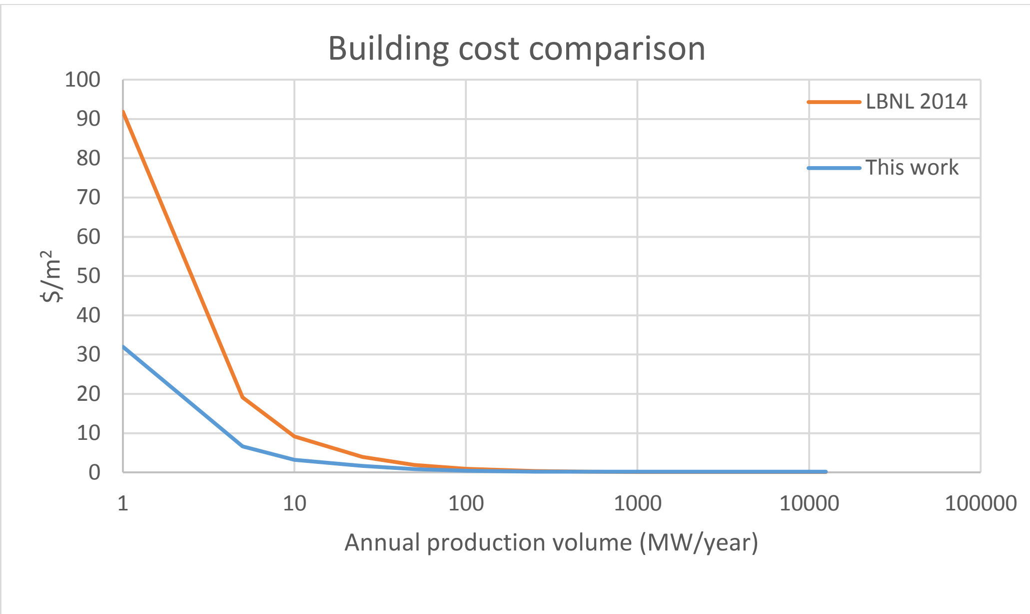

Figure 8-8 Building cost comparison

Building cost results are lower than LBNL report for different reasons:

- lower average mortgage rate
- lower average inflation rate
- lower property tax rate.

Scrap/recycle costs

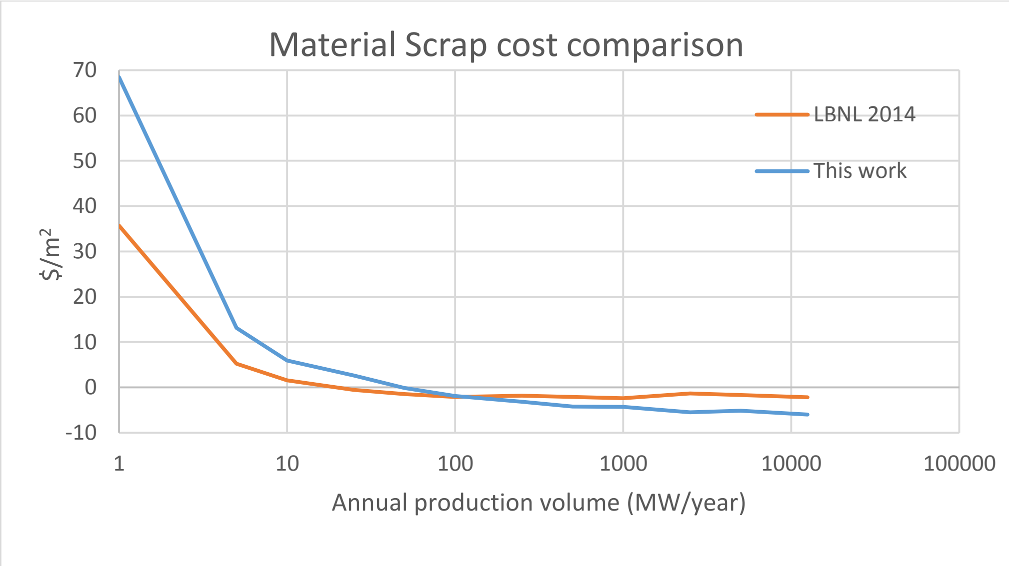

Figure 8-9 Scrap/Recycle cost comparison

At low production volume scrap costs obtained in this report are higher compared to LBNL results, as a consequence of lower process yields that increases CCM used Area respect to previos work. At high production volume a greater amount of rejected material causes bigger revenue due to Platinum recycle.

Conclusion

As expected the change of Platinum price is the factor that most affects the CCM overall cost, leading a to a CCM cost decrease from 2.6% (1 MW of annual volume) to 11.4% (12,500 MW of annual volume). A lower capital cost leads to a decrease of the total CCM cost of 15.3% at 1 MW of production volume.

8.1.1.1 Price of Platinum unchanged

As reflected in the cost results, the change of platinum price is a strong assumption that affects almost all annual production volumes.

To better appreciate all other data changes, cost results with price of Pt unchanged with respect to the previous LBNL report are analyzed. Table 8-1 summarizes CCM cost results for all annual production volumes.

Table 8-1 CCM cost results with Pt price unchanged

annual production volume (MW/year)	LBNL 2014 CCM costs $/m^2	This work CCM costs $/m^2
1	1,298,8	1,178,9
5	679,5	672,8
10	584,4	594,8
25	519,4	555,2
50	488,2	514,6
100	466,2	492,3
250	440,6	464,2
500	425,1	448,7
1,000	411,8	431,6
2,500	392,0	411,0
5,000	379,3	394,2
12,500	362,4	376,4

Figure 8-10 compares CCM manufacturing cost between LBNL 2014 cost analysis and this work, keeping the platinum price unchanged.

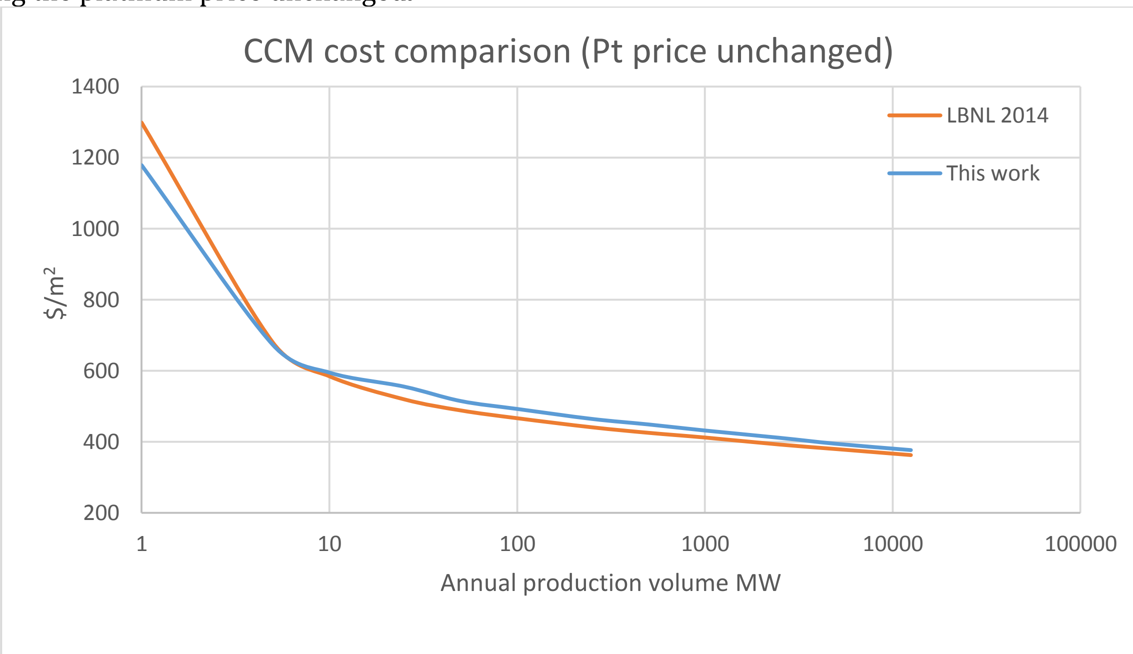

Figure 8-10 CCM cost comparison with Pt price unchanged

At high production volume: new CCM overall costs are higher than LBNL results because of higher material costs; despite material prices remained unchanged we assumed, for the present analysis cost, lower process yields.

At low production volume: since 1MW is the only case capital cost has a bigger impact on overall cost than material cost, this is the only point where the new CCM cost is lower than the LBNL cost.