CHP and Fuel Cell Evaluation Study for New Jersey

Phase I

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EXECUTIVE SUMMARY

Distributed generation (DG), specifically Combined Heat & Power (CHP), has emerged as a strategic opportunity for states seeking to meet energy demands in a more cost effective and environmentally responsible manner while increasing distributed generation resources. CHP installations now represent 8% of the U.S. electric generation capacity, yet yield ~12% of the annual power generation.[1] The U.S. Department of Energy (DOE) reports that the total onsite potential in New Jersey alone is 3,761 MW at 8,649 sites. This potential indicates that there are still technical opportunities for CHP advancement in NJ with the right economic and feasibility conditions.

For over a decade, New Jersey has deployed incentives to promote CHP and fuel cell technologies within the state when consistent with the state's policies and objectives. Growth of CHP within New Jersey can be attributed to the CHP & FC program managed by the C&I Market Manager for the New Jersey Clean Energy Program (NJCEP).

The table below summarizes the DG installations incentivized by the Small Scale CHP & FC program. Currently, there is about 28.4 MW of installed capacity from 44 projects across New Jersey.[2]. The majority of applications and projects use reciprocating engines, with fuel cell as the next most common primary mover for CHP. All of the CHP & FC systems use natural gas as a fuel and several of the systems utilize the waste heat for cooling purposes. In order to receive the NJCEP incentives, eligible projects, as defined by the program requirements, are approved through a simple payback method. For the projects listed in the table below, federal tax incentives were not include in the simple payback calculation. More specifically, for projects going forward, each project must meet a minimum efficiency standard and demonstrate they have a simple payback 10 years or less, including any federal tax credits and the incentive the project would receive through the program.

[1] Combined Heat and Power Technical Potential Study in the United States, DOE, March 2016

[2] The 23 committed/approved applications have either not purchased equipment and/or not completed installation yet

Number of Committed Projects by Primary Mover in NJ as of September 2016[3],[4]

Prime Mover	Number of Applications Received	Prime Mover % of Applications	Number of Installations	Total Installed kW	Prime Mover% of Installed kW
Reciprocating Engine	39	58%	25	13.8	48%
Combustion Turbine	5	7%	3	8.2	29%
Backpressure Steam Turbine	2	3%	2	0.76	3%
Microturbine	6	9%	6	1.83	6%
Fuel Cell[5]	15	22%	8	3.85	14%
Total	**67**	**100%**	**44**	**28.4**	**100%**

The New Jersey Board of Public Utilities, who has supported CHP and Fuel Cells since 2001, looks to provide incentives to those CHP and FC projects that deliver a clear net economic and environmental benefit to the State, consistent with the Energy Master Plan[6], and that also align with the NJCEP Strategic Plan. As these are distributed generation resources, there may be additional benefits to consider beyond what is currently captured in the simple payback calculations. Therefore, it is important to understand and reflect the full value that these resources can provide.

With moderate installation progress made and technical potential opportunities for CHP and FC still present, the Board seeks to evaluate the technologies and manner in which the State provides incentives to those types of DG projects.[7]

This report is Phase 1 of a two-part study that examines CHP-FC incentive structure and methods of evaluation in NJ and elsewhere and provides recommendations to help the BPU fulfill its mandate in developing DG resources.

METHODOLOGY

The Evaluation Team of the Rutgers Center for Energy, Economic and the Environmental Policy (CEEEP), Rutgers Center for Advanced Infrastructure and Transportation, Laboratory for Energy Smart System (RU LESS), TRC Solutions, Inc, and ICF International, Inc., collaborated on evaluating the current structure of CHP incentives in New Jersey and elsewhere and based their analysis and recommendations on four key inputs:

[3] NJCEP Combined Heat and Power Program Participants Spreadsheet, accessed at http://www.njcleanenergy.com/commercial-industrial/programs/combined-heat-power/combined-heat-power

[4] Please note the information is only provided for projects that have received an incentive for equipment purchased and/or installed. Project status is not confirmed, some projects have yet to be installed and some projects have retired, while others are still operational. These applications are only ones that have applied through the Small Scale CHP and FC program ran by the C&I Market Manager, this table does not include applications for the Large Scale CHP FC Program managed by the NJ Economic Development Authority (EDA). This table also excludes CHP projects fueled by biopower, which are addressed through the separate programs NJCEP CORE and REAP.

[5] None of the 15 fuel cell projects incentivized by the program recover waste heat. 14 of the 15 applications were review for preliminary economic analysis in Section 3

[6] NJ Energy Master Plan Update, 2011.Pg .5

[7] NJ Energy Master Plan Update, 2015 Pg.19

Literature Review of current DG programs

TRC reviewed DG programs in other states to understand the parameters used in other states to administer DG programs and establish incentive structures for CHP and FC. Based on this review, recommendations are made to the Office of Clean Energy staff on how to best provide support for these technologies through the NJCEP offerings.

A review of key technical studies related to the evaluation of DG technologies in other states was done to provide insight into the methodologies used and how grid related benefits may be factored into the evaluation. Based on this review recommendations are made in developing a more advanced framework for evaluation similar to that being proposed by RU LESS.

Data Review

ICF International team collected historic and current project data, and data from current CHP & FC applications in order to perform the cost benefit analysis and other economic analysis. The review of available data alone yielded important recommendations on establishing more robust reporting requirements to enable evaluations and ensure installed system are performing to the established standards.

Preliminary Economic Analysis

Rutgers CEEEP applied a CBA framework to past NJ fuel cell applications submitted to the NJ BPU. This was done as a first step to understanding the cost efficiency of FCs relative to other CHP systems. Based on these findings, recommendations are made on the use of CBA metrics for future CHP-FC incentives.

Consideration of Alternative Evaluation Methodologies

Rutgers LESS team proposed an alternative data driven methodology to be used in Phase 2 of this study that includes a system view of how DG technologies operate in context to factors such as tariffs, customer and CHP & FC characteristics/requirements, and access to wholesale markets. A description of the methodology RU LESS will be using is included in this report, detailed in Chapter 4. Phase 2 will include an evaluation of DG technologies using this alternative method.

Literature Review and Comparative Analysis

As part of **Phase I**, a literature review and comparative analysis was performed. The purpose is to provide background information and analysis on distributed generation (DG) technologies and the programs that support these technologies. This analysis will provide information on programs across the country, as well as compare and contrast the program's parameters with what is currently being offered in the New Jersey's Clean Energy Program (NJCEP) Combined Heat and Power and Fuel Cell program (NJ CHP &FC).

Analysis Overview

The analysis focuses on evaluation methodology and incentive structure for programs that support conventional CHP (microturbines, gas turbines, reciprocating engines, steam turbines) and fuel cell technologies, as these are most relevant to the NJ CHP & FC program. The core of this tasks' analysis is separated into three sections 1.) Current State of Programs across the Country, 2.) Review of Technical Studies, 3.) Review of Common Practices.

Twenty-two programs were reviewed including those from leading states like California, New York and Massachusetts. The analysis included a review of existing and recently expired programs that offer support for CHP and FC related technology across the country. The accounting provides information on program parameters including: program eligibility requirements, technologies included, incentive types and levels, and any available performance data for the programs. There are a select number of states and or utilities that explicitly call out or offer targeted incentives for CHP technologies – these include but are not limited to New York, Maryland, Massachusetts, California, Pennsylvania and Rhode Island.to New York, Maryland, Massachusetts, California, Pennsylvania and Rhode Island. Below is a highlight of three very different programs that offer incentives CHP and FC technologies.

State	Program Administrator	Program Title	Electric Only Eligibility	Incentive Structure Type	Incentive Structure
California	California Public Utilities Commission	Self-Generation Incentive Program	Yes	Tiered Capacity w/ performance incentive	Step1 - $600/kW & w/ bio gas $1,200 step 2 -$500/kW & w/ bio gas added $1,100; step 3 - $400/kW & w/bio gas added $1,000 Bonus 20% is available for the installation a California supplier. Projects >30 kW receive 50% of incentive at completion, remaining 50% as performance incentive for 5 years
Maryland	Baltimore Gas and Electric	Combined Heat and Power Program	No	Project cost payment w/ performance	**Design incentive** ($75/kW) **Installation incentive** $275/kW for projects under 250kW; $175/kW for projects 250 kW or greater) **Performance** ($0.07/kWh for 18 months) Capacity, performance incentives each capped at $1.25 mil.
New York	NYSERDA	Customer Sited Tier Fuel Cell Program Small	Yes	Performance Incentive	$0.15 per net kWh produced for sites with an annual capacity factor <=50% for 3 years after commissioning, max of $20,000 per year per project site, total cap of $50,000/project

More detail on program specifics are provided in Section 2.

Six of the twenty-two programs reviewed technically allow fuel cells without heat recovery, however three of those programs are more general alternative energy funds that do not state a minimum efficiency requirement. That leaves only the California Self Generation Incentive Program (SGIP) and New York State Energy Research & Development (NYSERDA) small and large fuel cell programs that incentivize fuel cells without heat recovery. Most programs either require waste heat recovery, set a high minimum efficiency, or require an economic or environmental screening, which may rule out fuel cell projects without heat recovery. The cost effectiveness metrics are reviewed and discussed further in Section 3, the Preliminary Fuel Cell Economic Analysis. A full matrix of all reviewed program attributes are included in Appendix A.

Additionally, technical studies were reviewed that describe how two of the states assess programs and technologies for cost effectiveness. The two studies are the most recent cost benefit analyses from states that have successful CHP programs.

Key Findings

- **Each program reviewed had a clear program objective – generation, emission reduction, market transformation etc.- that was reflected in how the program was designed**. In Maryland – for both the state program and utility programs – the objective is to incentivize the most cost effective projects. This objective is reflected in the fact that the programs do not incentivize electric-only fuel cells because the technology is generally deemed not cost effective. The program requires waste heat recovery and sets a high minimum efficiency level that typically rules out electric only fuel cells.

- **There are many ways to design incentives for promoting CHP and fuel cells, indicating there is no best practice for designing the structure.** Each incentive structure has pros and cons, and should be chosen based on the program objectives and the resources available to the program (i.e. budget, staff etc.). Some programs have simple one-time capacity rebates for all technologies with no additional bonuses, such as the Maryland Energy Administration's grant program offering $425-$575/kW (depending on system size). Others have complicated tiered incentive structures that decline with size, offering a combination of capacity and performance based incentives (i.e California's SGIP).
- **Successful programs[8], like programs run by NYSERDA and the California PUC, have technology neutral incentives, but diversify incentives when needing to tailor to specific technology needs or goals of the state**. In California, conventional CHP and fuel cells are provided the same incentive, however projects that utilize renewables (wind or biogas) receive a higher incentive.
- **Several states require the submission of annual performance data to provide performance based incentives.** Programs in states, like New York, California and Maryland, use the performance data to provide incentives, as well as, track and monitor project progress. New York (NYSERDA) goes as far as to track and monitor projects on a real time basis. Real time operational data is gathered and monitored through NYSERDA's DG Integrated Data System[9]
- **Other than New Jersey, no other state or utility program has offered distinct incentives for both fuel cells with and without heat recovery.** Of the twenty-two programs reviewed, there are only six programs where fuel cells without heat recovery are eligible technologies. For the other sixteen programs reviewed, a waste heat recovery requirement, minimum efficiency requirement, and or cost effectiveness screening may rule fuel cells without heat recovery ineligible. The NYSERDA fuel cell programs have a minimum efficiency requirement of 50%, stating in the program documents that the focus of the program is electrical generation benefits and therefore the recovery of waste heat is not required but recommended due to the benefits. The programs (small FC and Large FC) do not offer differing incentives for FC projects with or without heat recovery.
- **Most programs institute a singular minimum efficiency requirement that ranges from 60% to 65% to streamline the application and incentive process.** However – it is important to note that programs in New York, California and Pennsylvania do not follow this. New York has different requirements for separate programs (50% for all fuel cells, 60% for conventional CHP) and California has a lower efficiency requirement (40% for all technologies) – each due to the program objective. Also the PECO CHP program sets different efficiency levels based on the CHP technology in order to better tailor the requirements to typical individual CHP efficiencies.
- **Most programs, except New Jersey, Ohio, and Maine express the minimum efficiency requirement as HHV, Higher Heating Value, as opposed to LHV or Lower heating Value.** HHV is a more inclusive efficiency rating because it accounts for all available thermal heat, whereas LHV excludes heat from water vapor. HHV is more appropriate for CHP applications because of the inclusive nature of the efficiency calculations.

[8] As defined by number of installed projects and long history of program development. The NYSERDA and California SGIP have installed over 100 CHP and fuel cell projects over a long program history.

[9] http://chp.nyserda.ny.gov/home/index.cfm

- **Almost all programs have some sort of formal screening process for individual projects** – for example the Total Resource Cost (TRC) test[10], payback threshold and/or weighted criteria groupings. More states opt for the TRC cost effectiveness screening. States like Maryland, Illinois, and Rhode Island require a TRC ratio of 1.0 or higher. The programs in Ohio, Illinois, and Massachusetts have minimum payback requirements. California has a GHG threshold that projects must meet to receive incentives, this is directed to meet the program goal of emissions reductions.
- **In reviewing the technical studies on cost benefit analysis, both studies emphasized the use of the Societal Cost Test (SCT) to evaluate the cost effectiveness of distributed generation**. Both studies address the use of the SCT to evaluate DG at the program and project level. Both studies also discussed the use of a societal discount rate to better account for the longer life benefits and encourage the use of traditionally "hard-to-quantify" benefits or non-energy benefits. These might include reliability increases, strengthened customer empowerment, reduced emissions, etc.

DATA REQUIREMENT

ICF provided the necessary program data for the preliminary economic analysis. The data set included project details of all New Jersey Clean Energy (NJCEP) – Small Combined Heat and Power (CHP) and Fuel Cell (FC) Program[11] applications submitted during Program Fiscal Years 2013 through 2016. The calendar year date range which aligns with this time period is January 1, 2012 through June, 30, 2016.

Ninety-four projects were submitted to the program for approval January 1, 2012 – June 30, 2016. Forty-three CHP and FC projects reached the Commitment stage, where incentive monies are approved and reserved specifically for those projects. Reasons vary for why projects did not achieve program commitment, include: funding complications, technology glitches, site challenges, or construction issues. During this time period, fifteen applications (34.9%) proposed to use FC technology. The remaining twenty-eight applications utilize conventional CHP technology and will be analyzed in Phase II. To date, no FC projects in the Small CHP FC Program have reached a stage requiring submittal of twelve-month operational data.[12] Of the projects in this dataset, operational data was submitted for seven CHP projects.

The data points captured were consistent across individual projects, spanning a wide spectrum of detail; from applicant, contractor, and design team information to site photos, construction drawings, air emissions, and financial analysis. The dataset does not include operational data for the fuel cell projects, as the projects have not reached the stage in which the 12-month data is reported to the program. Detail on this data review is included in Section 3, Preliminary Fuel Cell Economic Analysis.

Some programs such as ones offered by NYSERDA collect operational data that can then be used to true-up incentives versus the stated efficiency or for program evaluation in terms of understanding system performance in specific use cases.

KEY FINDINGS

- Operational data is highly important to the economic analysis of the project and success of the program. Having operational data over a sufficient amount of time will enable the

[10] One of the cost-benefit analysis metrics described in detail in Section 3
[11] Managed by the C&I Market Manager
[12] One 2 MW fuel cell project that utilizes heat recovery, in the Large CHP FC project managed by EDA, has submitted operational data. This project was out of the scope for this evaluation report.

comparison of projections and assumptions made in applications to actual performance, which will help inform the Office of Clean Energy on future program changes and design.

PRELIMINARY FUEL CELL ECONOMIC ANALYSIS

The literature review section provides a foundation for understanding how other programs across the country incentivize and evaluate CHP and FC technologies. To understand how the cost benefit metrics may be applied to DG technologies in New Jersey, Rutgers Center for Energy, Economic and Environmental Policy (CEEEP) was asked to conduct a preliminary Cost-Benefit analysis (CBA) for DG technologies including fuel cell (FC) projects that do not have heat recovery. The goal is to further understand the economics of fuel cell technologies in New Jersey. This knowledge will help to inform how best to address fuel cells in the NJ CHP & FC program.

ANALYSIS OVERVIEW

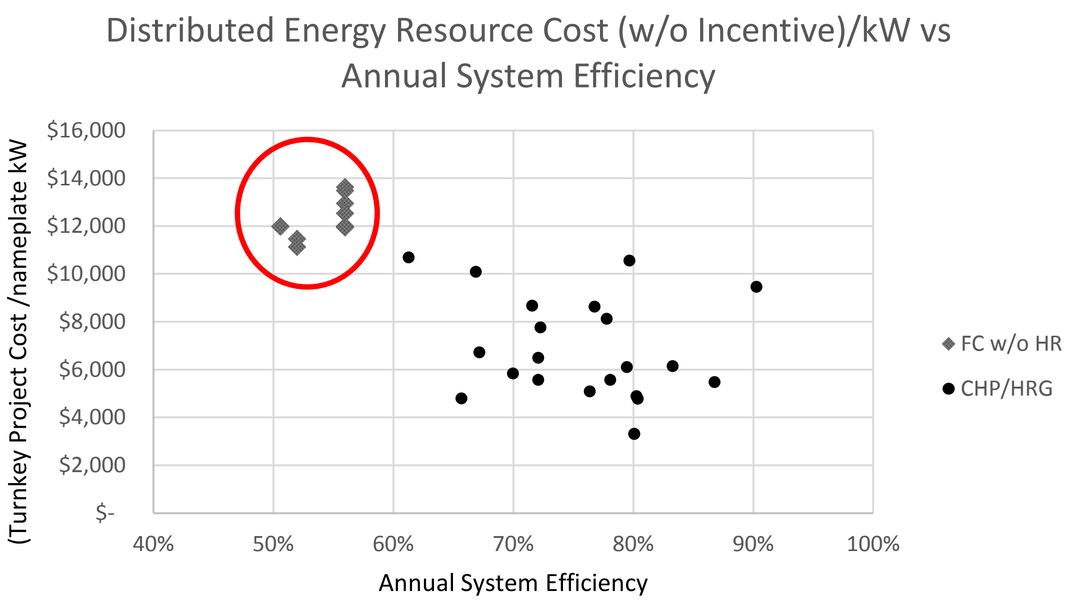
Using the Ben-Cost model developed by the TRC Solutions (TRC), the five standard energy efficiency CBA metrics are presented: societal cost test (SCT), total resource cost test (TRC), utility cost test(UCT), rate payer impact test (RIM) [13] and participant cost test for the fourteen fuel cell projects, based upon completed applications, that were analyzed as a part of Phase I. CEEEP also compiled a database of approved New Jersey fuel cell and CHP projects to compare their proposed installed costs versus their engineering efficiencies along with other financial and performance metrics such as payback, cost per kilowatt, capacity factors etc.

The project-level data was drawn from the fourteen completed FC without heat recovery applications submitted to the NJCEP Small Scale CHP & FC program from January 1, 2012 to June 30, 2016. The results from this analysis are preliminary due to limited availability of installation and operational data and additional analysis that is to be completed in Phase 2.

Two key characteristics of both FC and CHP are their proposed capital costs and their estimated efficiencies (both of which should be updated based upon actual installation and operations), which are plotted in the figure below.

[13] These metrics are described in detail in Section 3, the Preliminary Economic Analysis section.

Fuel Cell and CHP Proposed Capital Cost/kW vs Proposed System Efficiency



Projects that have low capital costs and high efficiencies, located in the lower right-hand side of the figure above, are preferable to those that have higher capital costs and lower efficiencies. The figure indicates that FC projects without heat recovery proposed to the BPU are clumped together in the upper left-hand side indicating that they have higher capital costs and are less efficient than the CHP projects.

The table below reports the CBA results using the Ben-Cost model for proposed FCs from application data.[14] Metrics below 1 indicate that the anticipated costs, on a net present value basis, are larger than the anticipated benefits, on a net present value basis. Metrics above 1 indicate that the benefits exceed the costs

Results for the Five CBA Metrics for Fuel Cell Applications

Project	TRC	Societal	Participant	RIM	Program Admin.
A	0.27	0.82	0.90	0.30	1.02
B	0.24	0.72	0.72	0.33	1.33
C	0.24	0.72	0.72	0.33	1.33
D	0.21	0.66	0.73	0.30	0.86
E	0.24	0.69	0.73	0.34	0.97
F	0.21	0.66	0.73	0.30	0.86
G	0.25	0.72	0.83	0.30	0.99
H	0.21	0.66	0.73	0.30	0.86
I	0.17	0.50	0.60	0.29	0.84
J	0.21	0.66	0.73	0.30	0.86

[14] To the extent that anticipated costs and anticipated benefits change after a project is constructed, commissioned and becomes operational, the modeled CBA is expected to be different than the actual results.

K	0.24	0.69	0.79	0.31	1.03
L	0.23	0.66	0.74	0.31	1.09
M	0.21	0.60	0.67	0.32	1.16
N	0.21	0.61	0.64	0.34	1.45

For the two metrics (SCT and TRC) that cover the broadest range of costs and benefits and therefore are useful indicators of the economic efficiency FC, the CBA metrics are less than 1 indicating that the costs exceed the benefits for the 14 applications evaluated. The Societal CBA metrics are closer to one than the TRC because it accounts for the environmental benefits that FC provide as compared to centralized power plants. The only CBA metric that for seven projects exceeds 1 is the PACT. As noted previously, the PACT only considers the costs and benefits to the program administrator and not the implications for ratepayers and society in general. More information regarding the definitions and uses of these CBA metrics is provided in Section 3 of this report.[15]

Simple payback was also assessed for the FC applications. In many of the recent FC proposals, the simple payback without incentives exceeds the expected life of the equipment. Simple payback periods with NJCEP incentives, but not federal or possible state tax incentives, factored in are typically three to five years shorter than if no incentive was applied. The expected life listed in each application ranged from 10 to 20 years, whereas simple payback periods without incentives ranged from 12 to 33 years. Simple payback periods with State incentives factored but not federal tax incentives in are typically 2 to 5 years shorter than if no incentive was applied, ranging from 10 to 27. The internal rate of return (IRR) for each FC project was also supplied. A negative or low IRR indicates that the project has no or low financial viability. IRRs without the incentive ranged from -1% to -22%. While the current analysis does not include the federal tax incentives, such as the Investment Tax Credit because of timing, additional analysis that incorporates the ITC was completed and will be included in future report iterations. More analysis is needed to properly consider the Modified Accelerated Cost Reduction System (MACRS), and any applicable property tax benefits.

Key Findings

The above analysis finds that:

- Long life actual installation and operational data and costs are essential to properly determining the cost effectiveness of a project.
- The evaluation method used will vary depending on the program objectives.
- The TRC and SCT metrics, which are the primary CBAs used to evaluate DG, fail to show a net economic benefit for FC without heat recovery. The Program Administrator metric is the only one that yields a positive cost-benefit for some FC without heat recovery.
- Budget limitations may prevent the funding of all projects whose SCT or TRC exceed one; thus it is important to not only compare CBA metrics to one but also to other project across technologies.
- Based upon the applications reviewed, FC without heat recovery are not currently cost-effective when compared to other DG or economically efficient based upon the TRC and SCT metrics, simple payback periods and IRR.

[15] See Rutgers CEEEP description of the five CB tests and their uses http://ceeep.rutgers.edu/wp-content/uploads/2013/11/EEGuidebook2009.pdf

- If the primary objective is to incentivize the most cost effective and or efficient systems, then the analysis suggests that fuel cells without heat recovery are not cost effective.
- Note that simple payback calculations in the current analysis does not account for the time value of money and therefore overestimates the economic value of capital-intensive assets such as FCs and CHP. The simple payback calculation also does not include the federal tax incentives due to the timing of the projects, applications and expiration of the credit. Additional analysis that includes the federal ITC was conducted afterwards and is to be included in future report iterations.

- When compared to CHP applications, based upon the applications reviewed, FC without heat recovery applications have higher capital costs and lower efficiencies than CHP.
- Future FC may provide resiliency benefits (as well as additional costs associated with being blackstart and islanding capable). In order to capture those benefits, the appropriate economic and financial metrics would have to be developed as part of Phase 2.
- These findings are preliminary and subject to change upon the receipt of installation and operational data, consideration of federal and state tax incentives, and the additional analysis that is proposed for Phase 2 of this project including the consideration of locational benefits and costs.

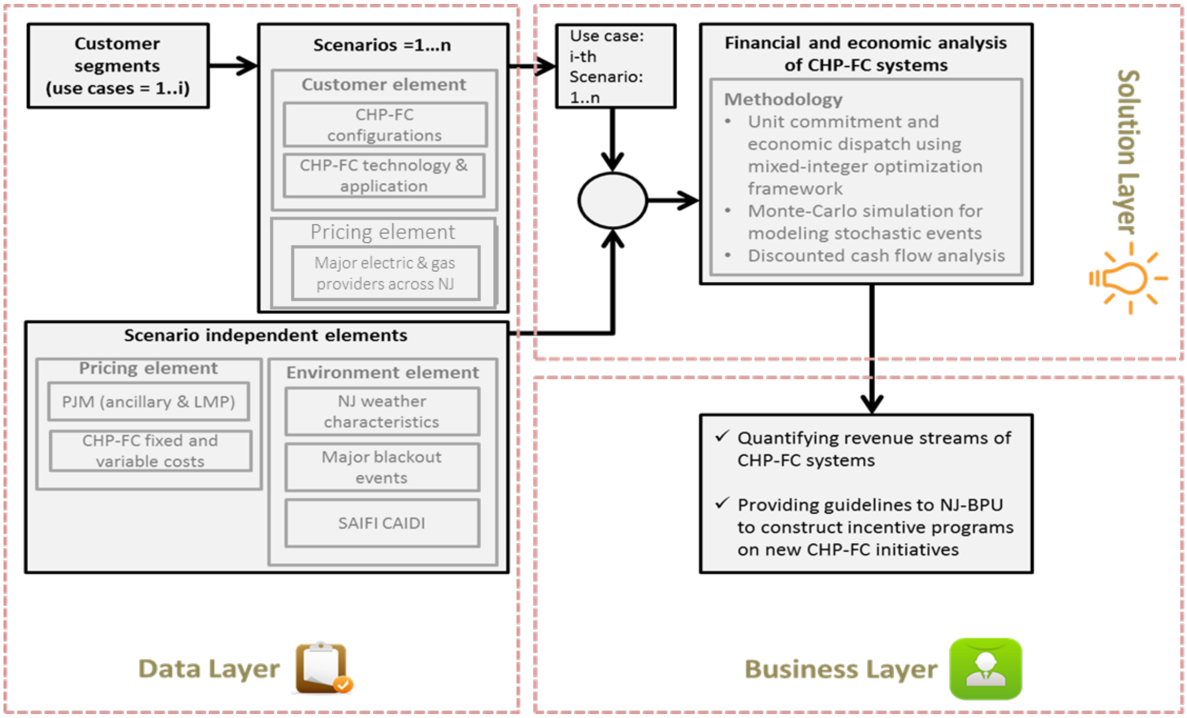
Data and Technology Driven Methodology

As a part of the scope of this study, a methodology for reviewing CHP & FC projects in New Jersey was requested. The proposed methodology is included below for Phase 1, results from the modeling which evaluates projects for the NJCEP will be submitted at a later data as part of Phase 2.

Methodology Overview

An alternative methodology for reviewing CHP & FC project in New Jersey was requested to help inform program design and evaluation criteria discussed in previous sections. The goal of this methodology is to capture the full value of DG technologies relative to different end use cases. The model described in this section provides an engineering backbone for more advanced economic analysis and takes into account the necessary operational parameters and detailed load profiles for various use cases.

To quantify and confirm the benefits of behind-the-meter (BTM) CHP & FC systems, Rutgers Laboratory for Energy Smart Systems (RU LESS) was engaged to develop models of CHP & FC projects and assist BPU staff to identify how various factors affect the cost-effectiveness and value of CHP & FC projects. The design and parameters of the proposed methodology was built in Phase I of the project along with preliminary experimental runs. Phase II.a involved additional CHP technologies and fuel cell with heat recovery, entailing extensive sensitivity analysis and the interaction between CHP/FC and other distributed energy resources (e.g. storage, etc.). It also included more use cases and additional model applications. The figure below illustrates the proposed methodology framework.



The objective of the model is to estimate the value, generated as a result of CHP & FC installation compared to the base-line (without DG). This value, along with the other cost elements such as project installation cost, will feed into the cost-benefit analysis model to determine the cost-effectiveness of each individual project. To fully estimate the value of DG on the grid, additional inputs would be needed from the utilities regarding distribution system benefits. Currently only avoided costs are included but additional inputs can be added if those data become available.

Model General Features

- The operational modeling of DG may help inform program design and evaluation criteria, and to improve the economic analysis using engineering data.
- The model intends to incorporate different components of CHP & FC systems to provide a complete picture of the system benefits, including but not limited to: different customer segments, size components, locations, operational costs, energy costs, facility thermal and electricity thermal demands.
- If operational data were to become available, it has been proposed that the model would utilize that data to quantify and confirm costs and benefits of various types of CHP & FC systems by utilizing operational data and estimating the net benefits, generated as a result of CHP & FC installation compared to the baseline (without DG).
- This same methodology can be adopted by applicants to evaluate the operational and economic outcomes of a project on both short- and long-term basis.
- Additional data inputs regarding the distribution system are necessary to evaluate grid related benefits beyond avoided costs.

Phase I Recommendations

These recommendations draw on the key findings and insights presented throughout this report and are detailed below. These recommendations may be refined should any actual operational data become available for additional experimental runs of the model.

1. **Clearly define primary program objectives, based on the NJ EMP and NJCEP Strategic Plan[16].** These objectives should then inform the program design. The primary program objective may be to 1.) promote strictly CHP (i.e. waste heat recovery), 2.) incentivize technologies that provide maximum energy saved per dollar, 3.) incentive systems that deliver net economic benefits, 4.) reduce the cost of energy for all customers, 5.) achieve high generation goals for CHP, 6.) advance emerging or underutilized technology, 7.) promote a diverse portfolio of new, clean, in state generation 8.) achieve high emissions reduction goals[17] or 9.) reduce peak demand. The objective or objectives that are selected by the Board will inform the types of analyses that are used to evaluate DG and the amount and structure of any incentives.
    - If the primary goal is 1-4, than the program would yield a more narrow definition of eligible technologies and would likely exclude fuel cells without heat recovery. While the 4-9 would direct a more broad definition of eligible technologies, potentially including fuel cells without heat recovery.
2. **Change the program structure and incentives to closely align with a clearly defined primary program objective. .** The following are potential program attributes that can be adjusted based on a clearly defined program objective. These are grounded on observations from leading programs across the country. These are highly subject to change after Phase II is completed and the primary program objective is defined.
    - *Create technology agnostic incentives.* The more simplified the incentive offering, the less education and administration required for program participants. Additionally, one technology is not promoted more than another, unless program objective directs otherwise. The California SGIP and NYSERDA programs have technology agnostic incentives diversify when needing to tailor to specific technology needs or goals of the state, i.e. bonus incentives for bio gas etc.
    - *Consider adjusting the minimum efficiency requirement to align with the established program objective.* Currently the program in New Jersey has an efficiency requirement of 65% LHV for CHP and FC with heat recovery technologies.
        - For example, if the objective of the program is promoting on-site generation in general or achieving high emission reduction goals (such as in New York and California), a lower program wide or dual efficiency requirement (i.e. what the NJ program had previously) would be recommended. If the objective of the program is to incentivize the most cost effective projects or to promoted CHP (i.e. heat recovery), than a higher minimum efficiency

[16] The NJCEP Strategic Plan is an ongoing planning process to improve the program offerings for the NJCEP. The goals are to update portfolio elements which are outdated and not reflective of national best practice and to optimally allocate precious budgetary resources across programs. The preliminary plan is guiding the development of refinements to the existing programs for FY17; the fuller strategic planning process – which requires both more time and significant input from the BPU – will set the stage for comprehensive change in direction for FY18 and beyond. There will be five steps to the strategic planning process: 1.) Setting policy objectives, 2.) Establishing clear detailed operating principles, 3.) Conducting baseline studies and other market research, 5.) Establishing portfolio-level targets, 5.)Plan a portfolio of programs. On-going evaluation and timely market research will also be incorporated into the planning process.

[17] For example, California clearly states that GHG emission reductions is the primary goal of the program, so any on-site generating units that have that to meet a GHG gas threshold in order to receive an incentive. The program uses the SCT cost effectiveness test as a secondary consideration.

would be recommended, such as programs Maryland and Massachusetts where cost effectiveness and high efficiency are priorities.

- *Express the minimum efficiency requirement in HHV, Higher Heating Value, rather than LHV, Lower Heating Value, to align better with what other jurisdictions and sources report, as well as, HHV is more appropriate for CHP applications*. Currently, NJ CHP-FC program expresses the efficiency requirement in LHV. Most programs express the minimum efficiency requirement as HHV, Higher Heating Value, as opposed to LHV or Lower heating Value. HHV is a more inclusive efficiency rating because the calculation accounts for all available thermal heat, whereas LHV excludes heat from water vapor. HHV is more appropriate for CHP applications because of the inclusive nature of the efficiency calculations.
- *Consider adjusting the incentive structure type.* Other types of incentives include a design incentive or performance incentive. Providing more involvement and assistance in the front and back end of project will improve the chances of operational success.
    - T*he performance incentive can help to ensure the longevity of the project.* California SGIP has 50% of the incentive given at installation, and 50% given over 5 years as a performance incentive for a project over a certain size threshold.
    - *Consider requiring a feasibility study or bonus incentive for those projects that include a feasibility study.* A feasibility study will help ensure that system performance and cost expectations are addressed, and a system is sized correctly for the electrical and thermal needs of the site.
- *Add bonus incentives for renewables (biogas) and/or critical facilities*. If one of the objectives is to promote renewables, this would generate market interest and movement for renewable DG projects. Using an adder on top of an existing incentive is more streamlined than offering an entirely separate incentive for just for renewable DG projects. If one of the goals is resiliency as it is in New York, adding a bonus incentives for projects at critical facilities (hospitals, police stations, communication facilities etc.) will promote that policy objective.

3. **Obtain and maintain operational data from project sites.** Limited operational data makes it difficult to evaluate cost efficiency based on actual system performance and to tie incentives to performance. Consider creating a sustained database where operational data is tracked and easily accessed. The state run programs in New York and California maintain comprehensive performance databases that are supported by more thorough reporting requirements. More operational data would better inform project evaluations and program direction.

    - Consider requiring applicants to submit an annual report on system performance for up to 5 years after commissioning. In addition, consider requiring that applicants must respond to surveys and performance inquiries for evaluation purposes and require applicants to notify the program administrators if the system is going to be retired. The more readily available data program administrators have the better the chances are for success of the individual projects and the program as a whole. If the incentive structure is adjusted to include a performance component that where performance data is submitted and payment for generation is received over multiple years, the system life of the project can be extended.

4. **Consider exploring alternatives and/or additions to the current evaluation methodology**, depending on the defined program objectives. The program objectives will direct which economic metrics should be used to evaluate individual projects and the overall portfolio
    - Consider the use of an alternative evaluation methodology such as a GHG threshold screening (California SGIP), a weighted criteria analysis (such as in Illinois, or other type of evaluation methodology that can account for broader grid benefits (and costs) such as resiliency, emission reductions, transmission and distribution investment savings locational benefits etc. of DG technologies may yield a different results and recommendations.
        - The results of the preliminary fuel cell economic analysis using the five CBA metrics and simple payback evaluation methodologies indicate that there is no net benefit for fuel cells without heat recovery. The analysis points out that the current methodology of simple payback may overestimate the economic value of these capital intensive DG technologies and does not account for potential benefits like resiliency.
        - The current evaluation does not incorporate the federal investment tax credit due to the timing of applications and expiration of the credit. Additional analysis that includes the federal ITC was conducted afterwards and is to be included in future report iterations. More analysis is needed to properly consider the Modified Accelerated Cost Reduction System (MACRS), and any applicable property tax benefits.

5. **Consider evaluating projects on an individual basis using one of the CBA metrics as an alternative or additional method,** based on defined program objectives**.** According to the literature review of other programs across the country, a common practice is to evaluate projects on an individual basis using the TRC metric.
    - If the primary objective is to incentivize the most cost effective projects, consider evaluating projects on an individual basis using the TRC. Many programs across the county use the Total Resource Cost test to evaluate projects on an individual basis. Programs in Rhode Island, Illinois, Maryland, Maine, and Massachusetts utilize the TRC test to screen individual project applications for the delivery of a program incentives.
    - If the non-energy benefits, like emission reductions or resiliency, are deemed a program objective when evaluating technologies, the use of the Societal Cost Test (SCT) should help to incorporate those concerns. In California specifically, a GHG is the primary assessment tool for project approval, and the SCT is secondary tool used to review projects and to review technologies at a higher level as a part of the program's impact evaluations. California calculates the CBA using the TRC inputs, but applies a societal discount rate that better values system lifetime benefits more.
    - If choosing either CBA metric, it is important to note that budget limitations may prevent the funding of all projects whose SCT or TRC yield net benefits; thus it is important to not only compare CBA metrics for each project but also to other projects across technologies.

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INTRODUCTION: PHASE I

The New Jersey Board of Public Utilities has engaged its Program Administrator and Evaluation Team in a study to help evaluate DG technologies and prioritize and develop the incentive program structures for statewide DG projects. The evaluation focuses on DG systems that include Combined Heat & Power (CHP) and Fuel Cell (collectively known as CHP & FC systems). The evaluation provides research on CHP & FC programs across the country and a preliminary cost benefit analysis. In addition, the evaluation will include a data-driven methodology that can address immediate concerns of the State, such as whether to incentivize projects that involve FCs without heat recovery. The evaluation consists of a Phase 1 and Phase 2, described in below task sections.

This methodology aligns with the State's Energy Master Plan (EMP), which includes the overarching goals to:

- Drive down the cost of energy for all customers
- Promote a diverse portfolio of new, clean, in-state generation
- Reward energy efficiency and energy conservation/reduction in peak demand

The EMP states that *"New Jersey's policy initiatives are centered on balancing these objectives in a cost-effective manner with respect to economic and political realities".*[18]

The project's methodology shall also align with the NJCEP Strategic Plan, which is currently under development with anticipated finalization during FY17.

Evaluation Team

The evaluation is a collaboration that includes Rutgers LESS, Rutgers CEEEP, TRC Solutions, and ICF International.

- Kathryn O'Rourke, ICF International
- Michael Ambrosio, TRC Solutions
- Frank Felder, Rutgers CEEEP
- Mohsen A. Jafari, Rutgers LESS

BACKGROUND

Since 2001, New Jersey has been supplying incentives for CHP & FC technologies through the NJCEP funded CHP & FC program and programs managed by the NJ Economic Development Authority (EDA) that are consistent with the State's EMP. The State EMP, in the goals listed above, specifies a preference for net economic and environmental benefits from ratepayer funded energy efficiency and renewable energy projects. The 2008 NJ EMP and 2011 NJ EMP

[18] NJ Energy Master Plan Update, 2011, pg. 4

Update identify CHP and Fuel Cells as a DG technology that can contribute to the State's Clean Energy Goals.

"Both distributed generation (DG) and combined heat and power (CHP) resources improve system reliability and utilize fuel more efficiently, especially for commercial and industrial (C&I) customers. The Christie Administration is committed to developing 1,500 MW[19] of new DG and CHP resources where net economic and environmental benefits can be demonstrated."[20]

Furthermore, the 2011 EMP acknowledges the specific role fuel cells may play:

"Fuel cells hold promise for emission-free DG, transportation applications and even energy storage, but they are expensive. Fuel cells can reduce the need for new transmission and distribution investments. Technology progress may improve the economic performance of fuel cells. New Jersey should continue to monitor fuel cell performance benchmarks." [21]

The 2011 EMP recognizes that fuel cells have the potential to play an important role in the State's energy future, but that the technology is capital intensive – which creates barriers for customers and complicates program design for program administrators.

The 2015 EMP Update calls for reform of the NJ CHP & FC program:

"With the current economic environment, and the low rate of participation in existing incentive programs, the remaining CHP market potential may be insufficient to produce additional new CHP without a more targeted effort. The State is pursuing strategic measures to advance new CHP, such as leveraging the outreach and funding available through the ERB and other means, including revisions to the NJCEP CHP and fuel cell incentive programs".[22]

The 2015 EMP update encourages the support of new DG in all forms, but a focus on reducing financial, technical and regulatory barriers for CHP & FC technologies is emphasized. The plan recommends evaluating the NJ CHP & FC program with the consideration of revising incentives the program provides.[23] This current evaluation looks to provide clarity on program design elements and evaluation of CHP and FC systems.

OBJECTIVES

As seen within the NJ EMP, CHP & FC investments are capital intensive for the customer as well as NJCEP. Also, the economic viability of these investments are highly dependent on several interdependent factors, which are often beyond the customer or NJCEP control, such as energy tariffs, customer type and usage characteristics (e.g., peak & base loads, power & thermal load levels, and waste heat). The findings from this evaluation can give insight to how the complex CHP & FC financial and economics work with respect to these underlying factors and can help various stakeholders and policymakers to realize planned financial objectives.

The following research objectives were used to help organize this report and the resulting recommendations on how to structure, incentivize and evaluate projects for a CHP & FC program..

- Provide written analysis of other similar programs across the country

[19] Much of this will include solar and other technologies, not limited to CHP and fuel cells.
[20] NJ Energy Master Plan Update, 2011.Pg 5
[21] NJ Energy Master Plan Update, 2011 Pg 10
[22] NJ Energy Master Plan Update, 2015 Pg. 19
[23] NJ Energy Master Plan Update, 2015 Pg 20

- Recommend factors and metrics that would be necessary to develop a DG program in NJ.
- Develop recommendations for how the NJCEP should structure and implement a DER program.
- Develop recommendations on how the program management team should evaluate applications.
- Make a recommendation on how to evaluate the cost effectiveness of a project or portfolio of projects (ie. simple payback, CBA models, a portfolio wide or individual application test, etc.)

METHODOLOGY

The Evaluation Team performed a series of tasks to understand how DG Programs in other markets are structured and then examined New Jerseys CHP-FC Program and conducted a preliminary economic analysis of CHP- FC systems. A couple key Technical Studies on methods of evaluation for DR technologies were reviewed and alternative evaluation methodology considered for New Jersey. The following outlines the methodology used to address the objectives:

Literature Review of current DER programs

This task was carried out by the TRC Solutions.

- Accounting of how many/what other states have DER programs
- Technical study review
- Review & reporting of common practices within the industry and regulators

Data Requirement and project scope analysis

This task was carried out by the ICF International team. ICF was tasked to:

- Provide historic data and information on CHP and Fuel Cell projects that have participated or are participating in the NJCEP C&I CHP FC Program
- Provide details on the program requirements and management of projects
- Provide all CHP and FC application design information submitted by the CHP and FC applicants for a NJCEP CHP or FC incentive.
- Provide the required one year operational data of CHP and FC projects that have participated or are participating in the NJCEP C&I CHP FC Program to CEEEP.

Preliminary Economic Analysis

This task was carried out by the Rutgers CEEEP team. CEEEP was tasked to:

- Provide avoided cost assumptions (electricity, natural gas, environmental, and resiliency assumptions), linking the technical and engineering analysis to CBA and cost-effectiveness models, and producing associated results.[24]
- Conduct a cost-benefit analysis and cost-effectiveness analysis based upon the literature review and data collection efforts of all CHP and FC applications based on the application design information submitted by the applicants to the NJCEP (Tasks 1 and 2), and to develop a consistent CBA and cost-effectiveness framework that could accommodate more complex engineering models down the road based upon Task 4.

Phase 1- CBA framework applied to past fuel cell applications submitted to the NJ BPU

Phase 2 - CBA applied to generic fuel cell technologies based upon the results of Tasks 1 and 2, this analysis will include more detailed operational data to be received at a later date.

Data and Technology driven methodology

This task is to be carried out by the Rutgers LESS team and deliverables will be scheduled in phases. RU LESS is tasked to:

- Develop an alternative evaluation methodology with a system view that captures the complex dynamics of distributed generation on the grid including factors affecting end-use customers. This includes applicable policies such as tariffs, customer and CHP & FC characteristics/requirements, and access to wholesale markets.
- Develop use cases and run Monte Carlo stochastic scenarios constructed to explore different state regions[25], eligible technologies and applications, and sizing of systems. Each use case will involve rigorous analysis over scenarios that cover a range of key factors that drive customers' economics. These factors include, but are not limited to:
    - Customers' type and load profiles (both thermal and electric)
    - Fuel and electric prices the customer is exposed to e.g., natural gas, electric tariffs
    - CHP & FC technology type and sizing
    - CHP & FC applications and value-added opportunities for the customers through energy bill management, resiliency, and wholesale market participation, etc.
    - Geographical and environmental vulnerability factors e.g., regional black-out events

    Phase 1 A general description of the methodology that is being developed by RU LESS is included in this report, detailed in Section 4.

    Phase 2 The proposed methodology will be applied to a range of DG technologies and recommendations will be provided on how best to incorporate relevant factors into the evaluation of DG technologies and into CHP-FC Program parameters.

[24] The avoided cost assumptions are included in Appendix B at the conclusion of the document

[25] The model also has been proposed to explore systems that operate in different areas on the distribution system, however, operational data is currently not available and therefore this step to yet to be determined.

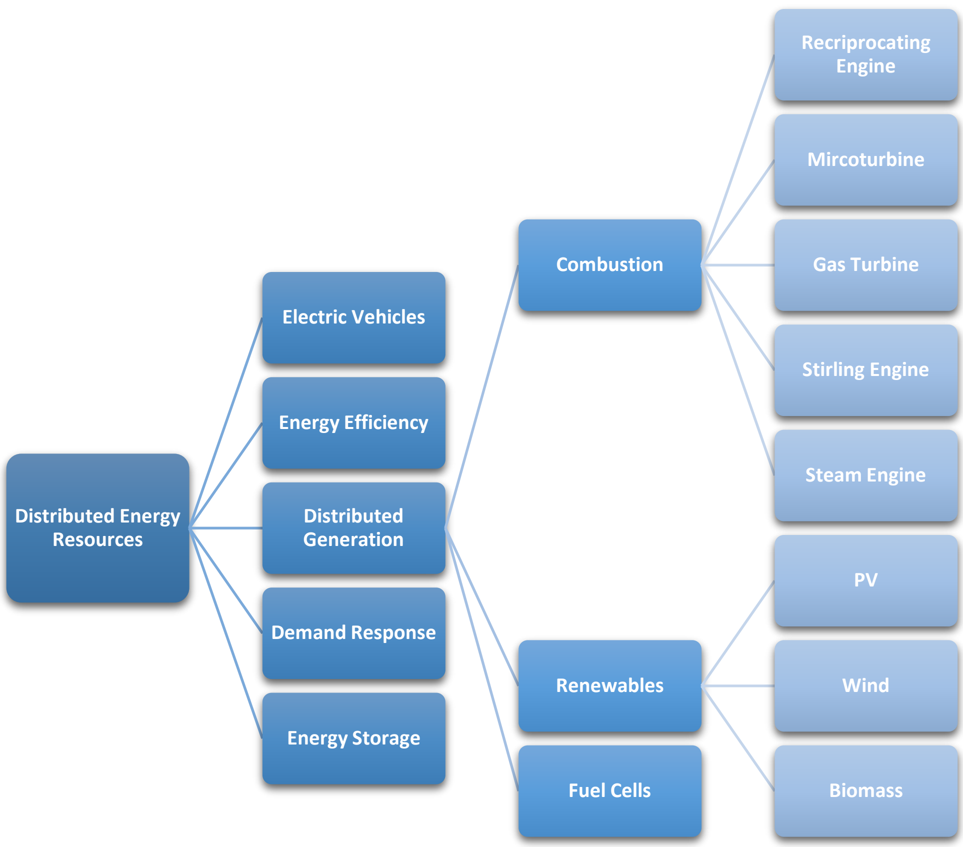
The following introductory section will briefly explain the technologies, the current state of those technologies in the U.S., and finally the brief history of the NJ CHP & FC program and how it is currently being implemented.

Review of Technology

Distributed Generation

Distributed Generation (DG), is defined as power generation resources located at or near the point of consumption that can provide all or a portion of the customer's electric and/or thermal load.[26] [27] The power can be generated using renewable (wind, solar, biomass/biogas) or non-renewable fuel sources (natural gas, diesel, oil, coal) with conversion technologies that include reciprocating engines, steam turbine combustion turbines, microturbines, and fuel cells. In general DG is subset of Distributed Energy Resource (DER) that can encompass many different energy related categories ranging from energy efficiency to demand response to distributed generation which provides substitutes and/or supplements to grid supply energy. This report only considers DG technologies as noted below. However, a combination of the DER technologies can be utilized in CHP and microgrid arrangements. Depending on the technology, residential and or non-residential uses may be applicable and are considered within this report. Figure 1-1 displays DG related technologies as a subset of Distributed Energy Resources (DER).

Figure 1-1 Distributed Generation as a Subset of Distributed Energy Resource Technology



[26] A Review of Distributed Energy Resources, DNV GL, September 2014
[27] Benefit Cost Analysis for Distributed Energy Resources, Synapse Energy, September 2014 http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

Although DG is not a new technology concept, with the introduction of innovative applications, such as alternative fuel sources, and increased emphasis on resiliency in recent years, interest in in DG development has accelerated, creating uncharted territory for many utilities and regulators.

State energy regulators and utility companies are rapidly investing in DG as a way to meet state renewable and efficiency energy goals, reduce electricity demand, provide grid resource flexibility, and fortify grid resiliency.[28]

Several states are leading the way for DG installations– California, New York, and Massachusetts [29]– driven primarily by their unique system constraints, rising electricity prices,[30]progressive state policies, and innovative program offerings. DG is quickly becoming an alternative option to traditional grid supply energy that is being incorporated into utility business models and state energy goals. This leaves these entities with several challenges as they enter new technology horizons.

Integrating more DG into the electric power system comes with difficulties related to policy and technical issues.

Despite these challenges[31][32], the future for DG is optimistic due to the declining cost of DG technologies and remaining projected technical opportunities for installations.[33]

Drivers for DG investment

- *Declining costs for DG technologies*
- *Supportive Federal and State energy and environmental policies*
- *Third Party ownership markets*
- *Customer expectations for self-generation, economic, and efficiency goals*
- *Reliability and flexibility in power supply*
- *Avoided infrastructure investments for utilities, and customer energy bill management*

Barriers for DG investment

- *Variable performance quality – efficient DG power supply is highly dependent on proper siting, installation and customer load profile;*
- *Variable performance quantity – intermittent and excess power production can negatively affect grid operations;*
- *Design of supportive policies – complexity in designing appropriate policies surrounding rates, interconnection, permitting/siting, incentives/compensation and financing;*
- *Risk in future DG development – the future of DG is highly uncertain as policies and technology are ever evolving.*

Technology Review

One of the objectives of the literature review and comparative analysis is to assess the programs that promote DG, therefore, it is important to understand the technologies these programs support. The following section briefly explains the DG technologies this analysis will focus on. The analysis will concentrate on technologies involved in customer sited CHP - as these are directly relevant to the research goal of providing guidance for the NJCEP CHP and Fuel Cell Program.

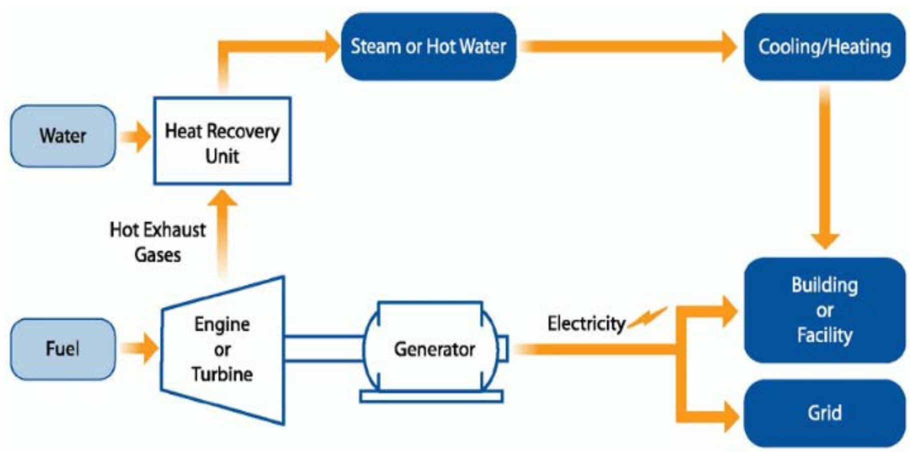
As defined in the NJ Energy Master Plan, Combined heat and power (CHP), or co-generation, provides electric and thermal energy from a single fuel source, thus obtaining high overall efficiency from the fuel.”[34] [35] The fuel source can be natural gas, biomass, process offgases,

[28] Distributed Energy Resources, Policy Implications of Decentralization, America's Power Plan, 2013
[29] A Review of Distributed Energy Resources, DNV GL, September 2014
[30] The Distributed Generation Market Demand Model (dGen):Documentation, NREL, February 2016
[31] While most of these challenges listed are out of the scope of NJCEP, they are important to keep in mind
[32] Barriers to DG investment are sourced from A Review of Distributed Energy Resources, DNV GL, September 2014
[33] Combined Heat and Power Technical Potential Study in the United States, Department of Energy, March 2016
[34] NJ Energy Master Plan, December 2015 http://nj.gov/emp/docs/pdf/New_Jersey_Energy_Master_Plan_Update.pdf

landfill gas, biogas, coal, etc.[36] CHP provides an alternative to the typical scenario of purchasing electricity from the grid from centralized generation, and burning a fuel in a separate boiler or furnace to generate thermal energy.[37]

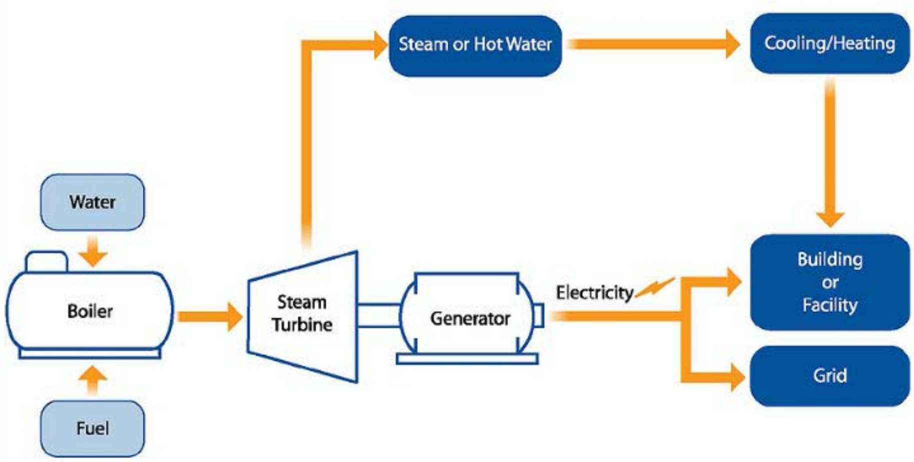
CHP can be seen as a clean energy option because of the reduction in energy, and therefore emissions, that occurs from the efficient use of thermal energy that would have otherwise been wasted. CHP systems must be sized and installed properly for the full efficiency benefits to be realized. Efficiency when applied to CHP systems is defined as how electrical and thermal energy are generated and utilized, i.e. the total energy input compared to the total utilized energy output. CHP and FC technology efficiency is typically expressed in either High Heating Value (HHV) [38] or Lower Heating Value (LHV) [39], these values express the total thermal energy available. HHV is a "gross" rather than a "net" measurement—i.e. it captures all the heat released by a combustion mixture, whereas LHV is the HHV minus the heat of vaporization of water.[40] When electrical and thermal energy are generated separately the efficiency can range from 45-55% HHV; when waste heat is recovered in a properly designed and installed system (depending on the type of system and fuel) efficiency can increase to 65-85% HHV. The below Figure 1-2 and Figure 1-3 show the two types of CHP system configurations.

Figure 1-2 Combustion Turbine or Reciprocating Engine with Heat Recovery Unit[41]



[35] Ibid
[36]Combined Heat and Power: A Resource Guide for State Officials, NASEO, 2013
[37] Ibid
[38] "Higher Heating Value (HHV): refers to the heating value of the fuel and is defined as the total thermal energy available, including the heat of condensation of water vapors, resulting from complete combustion of the fuel versus the Lower Heating Value (LHV) which assumes the heat of condensation is not available". IL TRM v5.0 Vol 2_February 11,2016_Final, page 292 in C&I section. CHP
[39] Ibid
[40] More detail of HHV and LHV calculations. http://www.omni-test.com/publications/1%20%20LHV%20HHV%20Variation%20rev10.pdf
[41] "What is CHP", Combined Heat and Power Partnership, EPA - https://www.epa.gov/chp/what-chp

Figure 1-3 Steam Boiler with Steam Turbine[42]



The system in Figure 1-2 depicts the more common configuration where fuel is burned in a turbine or engine to produce electricity while the waste heat exhaust gases released from the generation process are recovered to provide thermal energy for heating or cooling. Figure 1-3 shows an alternative method that burns fuel in a boiler to generate electricity through a steam turbine.[43]

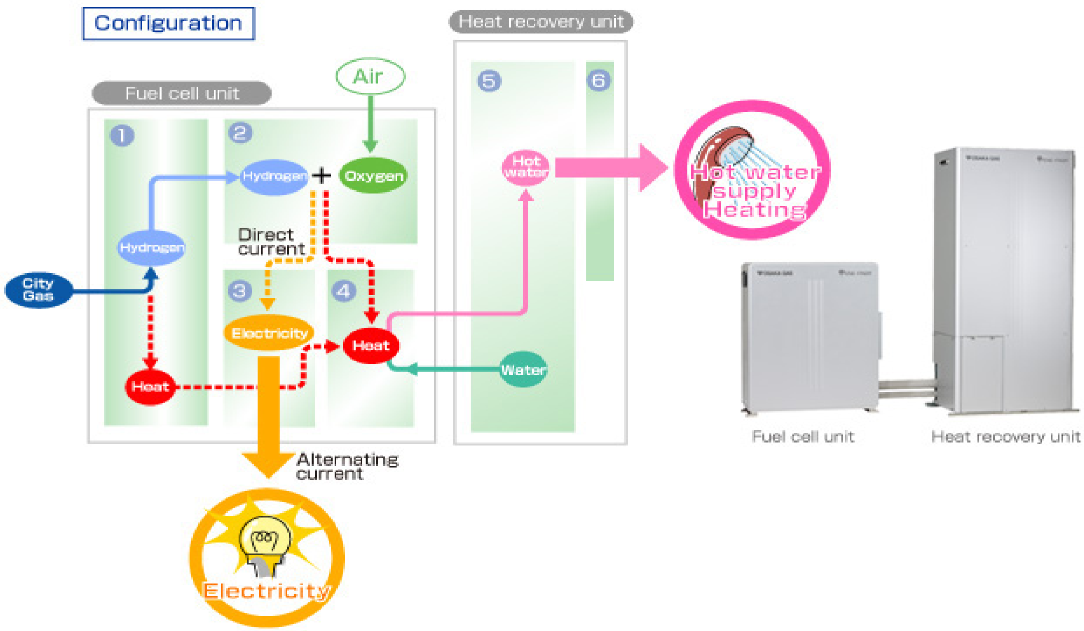
Another configuration is a "waste to heat power" (WHP) system where fuel is first combusted in a furnace as a part of an industrial process. Waste heat is produced and recovered through a heat exchanger to create thermal energy. The thermal energy is then sent through a turbine generator to create electricity.[44]

Fuel cells are another technology that can be used in CHP applications. While fuel cells have been in existence for a number of decades, issues with policy, technology, and cost barriers have kept fuel cells from flourishing as other DG technologies have[45]. An increased importance for clean energy and resiliency have led to a rise of CHP installations, and ultimately has provided increased interest and support for fuel cell expansion.

As defined by the DOE, fuel cell technology converts the chemical energy stored hydrogen into electrical energy, with water and heat as the only byproducts.[46] Hydrogen does not exist singularly in nature, and therefore must be extracted from a hydrocarbon fuel source, such as natural gas, biogas.[47],[48], or electrolyzed from water. The byproducts can be recovered through CHP configurations. Fuel cells, like batteries, produce power through an electrochemical process without combustion. However, fuel cells can operate continuously through a supplied fuel source, whereas batteries can only operate off of finite stored energy.[49]

[42] "What is CHP", Combined Heat and Power Partnership, EPA - https://www.epa.gov/chp/what-chp
[43] Combined Heat and Power: A Resource Guide for State Officials, NASEO, 2013
[44] Ibid
[45] NJ Energy Master Plan 2011, http://www.nj.gov/emp/docs/pdf/2011_Final_Energy_Master_Plan.pdf
[46] DOE Fuel Cell Fact Sheet http://www.energy.gov/sites/prod/files/2015/11/f27/fcto_fuel_cells_fact_sheet.pdf
[47] Ibid
[48] U.S. Environmental Protection Agency and U.S. Department of Energy, Catalog of CHP Technologies, Section 6 Fuel Cells, March 2015
[49] Ibid

Figure 1-4 CHP – Fuel Cell Configuration[50]



Fuel cells are between 30-60% (HHV) efficient and when waste heat is recovered the total system efficiency can increase up to 80-85% (HHV).[51] In fuel cell applications heat can be recovered to provide space heating or conditioning of reactant gases.[52] There are four types of fuel cells that are typically used for DG, each with a multitude characteristics described in the following section.

Benefits and Barriers: Technologies Compared

DG technologies offer varied benefits and barriers dependent on their unique characteristics. The needs and use profile of the end user will dictate the appropriate technology and fuel that will maximize the benefits and reduce barriers. Table 1-1 provides a detailed summary of available technologies used in CHP applications.

[50] "About a Fuel Cell", Osaka Gas http://www.osakagas.co.jp/en/rd/fuelcell/pefc/fuelcell/index.html

[51] "Fuel Cell Explained" Pragma Industries http://www.pragma-industries.com/technology/fuel-cell-explained/

[52] Ibid

Table 1-1 Distributed Generation Technologies for CHP Applications

DG Technology	Typical Size[53]	Typical Cost[54]	Efficiency (HHV[55])[56]	Applications[57]	Advantages	Disadvantages
Reciprocating Engine	5 kW residential machines up to 18 MW for large commercial	$1,500 - $2,900 per kW, O&M costs $0.1-0.25 per kWh	50% part load efficiency, 70%+ w/ waste heat recovery	Emergency/auxiliary power Distributed generation Peak Shaving	Proven reliable technology Relatively low installed costs Quick start up Black start capability High part load performance and operating flexibility High availability & capabilities Suitable for CHP Fuel flexibility	Maintenance intensive Higher O&M costs May require emission controls – Nox,CO,SOx
Combustion (Gas) Turbine	500 kW-300 MW for power only gen and CHP applications (1-2 MW)	$1,500 per kW for a 20 MW system, 3,300 per kW for a 3.5 MW system, O&M costs, $0.0092 - $0.0126 per kWh	50%-62% Electrical efficiency, 65%-75% w/ waste heat recovery	Electric Utility Mechanical drive – oil and gas production, industrial processes Distributed generation	Proven reliable technology Low air emissions Suitable for CHP Fuel flexibility	Poor part load performance Difficult to control air pollutants Require high pressure has or in house gas compressor Require persistent preventative maintenance
Micro turbine	30 kW to 330 kW, 30 kW-1MW for CHP	$2,500 -4,300 per kW for a 1MW to 30 kW, O&M costs $0.009 - $0.0016 per kWh	30% full load, 25% at part load efficiency 60-70% efficiency w/ heat recovery	Peak Shaving & base load power (grid parallel) Microgrid Combined cooling heating and power (CCHP) Distributed generation	Low air emissions Small footprint Highly modular and market availability Multiple unit installation for load following capability High Fuel flexibility Well suited for CHP Less maintenance required	High installed costs Require high pressure gas supply or booster compressor Few major players in the market

[53] U.S. Environmental Protection Agency and U.S. Department of Energy, Catalog of CHP Technologies, March 2015
[54] Ibid
[55] See footnote 14 on page 3
[56] Ibid
[57] Ibid

DG Technology	Typical Size[58]	Typical Cost[59]	Efficiency[60]	Applications[61]	Advantages	Disadvantages
Steam Turbine	100 kW to 250 MW, 500 kW to 15 MW for CHP	$650-700 per kW for a 3-15 MW, O&M cost $0.009-$0.006 per kWh	10%-45% electrical efficiency, thermodynamic efficiency 65%-90%, 70-85% w/ waste heat recovery	District heating and cooling Electric utility Mechanical drive Distributed generation	Mature technology Long service life High reliability and availability Fuel flexibility, included solid waste Wide range sizes and designs	Long start times Limited to high duty applications Low electrical efficiencies
Fuel Cell – PAFC[62]	5 kW-400 kW	$7,000 per kW, O&M Cost $0.036 per kWh	34.3%, 81% electrical efficiency w/ heat recovery	Auxiliary + Portable power Military	High temperatures suitable for CHP Increased tolerance to fuel impurities	Platinum catalyst = expensive Start up time Low current and power
Fuel Cell - PEMFC[63]	<1 kW – 100 kW	$22,000 per kW, O&M cost $0.06 per kWh	35.3% electrical efficiency , 86% w. heat recovery	Back up Power, Portable Power Distributed generation Transportation Specialty Vehicles	Reduced electrolyte component corrosion and management Low temperature Quick start up	Not as well suited for CHP Expensive catalyst Sensitive to fuel impurities
Fuel Cell - MCFC[64]	300 kW – 3 MW	$4,600-$10,000 per kW, O&M cost $0.040 -$0.045 per kWh	42.5% - 47% electrical efficiency, 82% w/ heat recovery	Auxiliary power Electric utility Distributed Generation	High efficiency + Fuel flexibility Suited for variety of catalysts Well suited for CHP	High temperature = corrosion and breakdown in system Long start up time Low power density
Fuel Cell - SOFC[65]	1 kW – 2 MW	$23,000 per kW, O&M cost $0.055 per kWh	54.5% electrical efficiency, 74% w/ heat recovery	Auxiliary power Electric utility Distributed Generation	High efficiency Fuel flexibility Suited for variety of catalysts Reduced electrolyte corrosion and management Well suited for CHP	High temperature causes corrosion and breakdown in system Long start up time due to high temperature
Additional Utility Generation Units for	**Nominal Capacity**	**Overnight Capital cost**	**Heat Rate**	**Applications**	**Advantages**	**Disadvantages**

[58] U.S. Environmental Protection Agency and U.S. Department of Energy, Catalog of CHP Technologies, March 2015
[59] Ibid
[60] Ibid
[61] Ibid
[62] Phosphoric Acid Fuel Cell
[63] Proton Exchange Membrane Fuel Cell
[64] Molten Carbonate Fuel Cell
[65] Solid Oxide Fuel Cell

Comparison[66]

Conventional Combined Cycle Gas turbine	620 MW	$917/kW, $13.17/kW-yr of fixed O&M costs	7,050 btu/kWh	Utility scale generation	Mature Technology Long service life High reliability and availability	High capital costs due to size Difficult to control air pollutants
Conventional Gas Turbine	85 MW	$973/kW, $7.34/kW-yr of fixed O&M costs	10,850 btu/kWh	Utility scale generation	Mature Technology Long service life High reliability and availability	High capital costs due to size Difficult to control air pollutants

[66] Updated Capital Costs Estimates for Utility Scale Electricity Generating Plants, U.S. EIA, April 2013 http://www.eia.gov/forecasts/capitalcost/

Cost and application are key factors in deciding the appropriate technology. Reciprocating and combustion engines are a well trusted and reliable technology that offer more affordable installed costs, but have higher maintenance and may require pollution control technology. Fuel cells have the highest installed costs and high O&M costs[67], but can offer high efficiencies in CHP configurations. Fuel cells may not be the most ideal candidate for CHP configurations depending on the budget, thermal size and thermal needs of the facility.

Another highly important factor for CHP is the quality and quantity of waste heat produced by the primary generating unit (for example reciprocating engine or fuel cell). The quality and quantity of waste heat varies and dictates the type of thermal application for that waste heat. Each DG technology, except for two types of fuel cells (PAFC, PEMFC) are suitable for the following types of waste heat recovery applications: water, space heating, low pressure steam, high pressure steam, and absorption chilling. PAFC and PEMCF are only well suited for water and space heating for domestic and off grid applications due to their lower operating temperatures.[68] For lower temperature fuel cells, there is less fuel flexibility and hydrogen-containing fuels must be processed in an external chemical reactor – raising the cost of the fuel system.[69]

CURRENT STATE OF DISTRIBUTED GENERATION

United States

The number of Installations in the United States have grown gradually over the years. An early spike in growth occurred from 2000 to 2005, though in recent years, added incremental capacity has slowed.[70] CHP installations are approximately 8% of the U.S. electric generation capacity, yet yield ~12% of annual power generation.[71] CHP contributes a higher percentage of actual annual power generation, than the total installed capacity due to relatively longer operating hours.[72] Table 1-2 presents the current state of CHP in the U.S. Reciprocating engines make up the majority of CHP installations, however, combustion turbines contribute the majority of capacity due to the larger typical system sizes. Table 1-3 shows that the majority of sites are supplied by natural gas (80%), this is due to the high availability and lower cost of natural gas.

[67] A component of the system called the "stack" typically needs to be replaced 5-7 years after installation, this is a large capital expense that is a hardship for many fuel cell projects. Specialized equipment maintenance and operation are also contribute to high O&M for fuel cells.
[68] "Fuel Cell Explained" Pragma Industries http://www.pragma-industries.com/technology/fuel-cell-explained/
[69] Ibid
[70] The Opportunity for CHP in the United States, ICF, May 2013
[71] Combined Heat and Power Technical Potential Study in the United States, DOE, March 2016
[72] Ibid

Table 1-2 Number of Installations by Primary Mover in the U.S. as of December 2015[73]

Prime Mover	Number of Installations	% of Installations	Capacity (MW)	% of Capacity
Reciprocating Engine	2,335	54%	2,352	3%
Combustion Turbine	651	15%	51,767	64%
Boiler/Steam Turbine	767	18%	26,002	32%
Microturbine	366	9%	91	0%
Fuel Cell	126	3%	67	0%
Other	60	1%	689	1%
Grand Total	**4,305**	**100%**	**80,969**	**100%**

Table 1-3 Number of Installations by Fuel Type in U.S. as of December 2015

Prime Mover	Number of Installations	% of Installations
BIOMASS - Biomass	334	8%
BIOMASS - Digester Gas	208	5%
BIOMASS - LFG	89	2%
COAL - Coal	181	4%
NG - Natural Gas	2,812	65%
NG - Propane	6	0%
Oil	252	6%
Waste Product	260	6%
Wood & Wood Waste	116	3%
Other	47	1%
Grand Total	4,305	100%

According to a recent CHP Technical Potential Study[74] conducted by the DOE, there is still room to grow for the U.S. CHP market. Total technical potential for all business types is 240 GW, which is around three times as much as the current installed capacity. Much of the potential capacity is concentrated in on-site industrial and commercial CHP. The highest number of applicable CHP sites are concentrated in potential systems between 50-500 kW (220,459 systems), with the most potential capacity added occurring from systems over 20 MW (110,913 MW).

This potential is concentrated in the states with dense population centers and large C&I sectors, i.e. California, New York, Texas.[75] For New Jersey, potential and market penetration is also quite high. Total onsite potential is 3,761 MW at 8,649 sites.[76] This potential indicates that there are still technical opportunities for CHP advancement in NJ with the right economic and feasibility conditions. While some of the economic and feasibility conditions, such as changes Renewable Portfolio Standard eligibility, tariff reform or interconnection policies, may be out of scope for NJCEP – they are important to keep in mind when considering the opportunities to advancement of CHP.

[73]U.S. DOE ICF CHP Installation Database, Dec 2015 https://doe.icfwebservices.com/chpdb/

[74] Technical potential does not screen for any economic considerations, siting & sizing properties, market conditions, etc. that considerably affect an end user's ability to physically and financially install CHP. Source: IFC opportunity report

[75] Combined Heat and Power Technical Potential Study in the United States, Department of Energy, March 2016

[76] Ibid

New Jersey

Since 2001 New Jersey has deployed incentives to promote CHP and fuel cell technologies within the state when consistent with its policies and objectives. The NJ EMP has laid out goals of advancing distributed generation, i.e. CHP and FC technologies, where "net economic and environmental benefits can be demonstrated".[77]

The table below summarizes the DG installations incentivized by the NJCEP Small Scale CHP & FC program run by the C&I Market Manager. Currently, there is about 28.4 MW of installed capacity for 44 projects across New Jersey. The 23 committed/approved applications have either not purchased equipment and/or not completed installation yet. The majority of applications and projects use reciprocating engines, with fuel cell as the next most common primary mover for CHP. Reciprocating engines and combustion turbines have the largest capacity. All of the CHP & FC systems use natural gas as a fuel and several of the systems utilize the waste heat for cooling purposes.

Table 1-4 Number of Committed Projects by Primary Mover in NJ as of September 2016[78],[79]

Prime Mover	Number of Applications	Prime Mover % of Applications	Number of Installations	Total Installed kW	Prime Mover% of Installed kW
Reciprocating Engine	39	58%	25	13.8	48%
Combustion Turbine	5	7%	3	8.2	29%
Backpressure Steam Turbine	2	3%	2	0.76	3%
Microturbine	6	9%	6	1.83	6%
Fuel Cell[80]	15	22%	8	3.85	14%
Total	**67**	**100%**	**44**	**28.4**	**100%**

Note: These committed projected were supplied by ICF in a data. A subset (between January 2012 and June 2016) of fuel cell applications were reviewed in the Phase I economic analysis in section 3. 14 of the 15 applications during that timeframe were review in section 3. The conventional CHP applications are to be reviewed in Phase II.

Growth of CHP within New Jersey can be attributed to the CHP & FC program managed by the C&I Market Manager for the NJCEP. The CHP & FC program began in 2001 as a standalone C&I program in which incentives were offered to qualifying customs, contractors, and energy services companies (ESCOs) for the installation of different types of CHP systems.[81] The program

[77] NJ Energy Master Plan Update, 2011.Pg 5

[78] NJCEP Combined Heat and Power Program Participants Spreadsheet, accessed at http://www.njcleanenergy.com/commercial-industrial/programs/combined-heat-power/combined-heat-power

[79] Please note the information is only provided for applications that have received an incentive for equipment purchased and/or installed. Application status is not confirmed, some applications have yet to be installed and some have retired, while others are still operational. These applications are only ones that have applied through the Small Scale CHP and FC program ran by the C&I Market Manager, this table does not include applications for the Large Scale CHP FC Program managed by the NJ Economic Development Authority (EDA). This table also excludes CHP projects fueled by biopower, which are addressed through the separate programs of NJCEP CORE & REAP.

[80] None of the 15 fuel cell projects incentivized by the Small Scale CHP FC program recover waste heat. 14 of the 15 applications were reviewed for the preliminary economic analysis in Section 3.

[81] 2008 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP December 2007

budget and scope has expanded over the years. **The following are a few of the initial core program requirements for the NJCEP CHP-FC Program:**[82]

- Incentives paid up to $1 million for the installation of new permanent systems
- At least 60%[83] efficient with waste heat recovery required
- Incentives ranged from $0.50/W for the addition of heat recovery to existing systems to $4.00/W for non-renewable fueled fuel cells
- Incentives were capped at 30%-60% of project costs, depending on technology
- Warranty or service contract for 5 years
- Applicants must be contributors to the Societal Benefits Charge fund.

In 2009, the stand alone program was removed for FY 2010 and wrapped into another existing program, Pay-for-Performance (P4P). The goal was to "make CHP part of a comprehensive, whole building approach to energy efficiency in existing commercial and industrial buildings" [84] Much of the previous standalone program was maintained, but customers also had to meet P4P requirements. In the P4P program, incentives were linked to energy saved through a detailed measurement and verification process for customers who have an annual kW demand of 200 kW or more[85]. In order to be eligible to receive the CHP incentive, applicants had to reduce their usage by 15% (the P4P minimum), meaning CHP projects had to be included with other P4P projects. The intent was to have applicants reduce usage first to allow for the installation of smaller CHP systems at a lower cost. In removing the standalone program, the annual solicitation was eliminated, supplying the opportunity for year round funding for CHP.

Incentives were revised in 2010 for FY 2011, adding a tiered structure where incentives were reduced as the size of the project increased. For example, incentives for CHP powered by Class 1 renewables ranged range from $5.00/W for <10kW to $0.65/W for 1,000 kW. [86]

In 2012 for FY 2013, the CHP program was pulled out of the P4P program and regained status as a standalone program with a new emphasis on fuel cells. Customers could still receive an additional incentive of $0.25/W for CHP and fuel cells through the P4P program, as a bonus to incentives for projects up to 1MW in the standalone program. [87][88] An additional program, the Large CHP and Fuel Cell Program, was created for CHP/FC projects that exceeded 1MW to be administered by the NJ Economic Development Association (EDA).[89] Different requirements were set for CHP and fuel cell projects. In addition, different incentives were provided for fuel cells with heat recovery and without heat recovery. In general, over the life of the program, fuel cells with heat recovery were designated with a larger incentive. The following FY 2013 program modifications were made:[90]

- Split out FC incentive to with and without heat recovery

[82] 2008 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP December 2007
[83] Based on total energy input and total utilized energy output. Mechanical energy may be included in the efficiency evaluation.
[84] 2009 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP November 2008
[85] Ibid
[86] 2010 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP, June 2010
[87] Projects receiving both incentives were subject to the CHP & FC program % of project cost caps or $2.25 million, whichever is less.
[88] 2013 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP, November 2012
[89] Ibid
[90] Ibid

  - FC projects with waste heat recovery had to the meet the same 60% efficiency , without waste heat recovery had to meet an electric system efficiency of at least 45%[91] [92]

- Added FC without waste heat recovery incentive of $3.00/W, with cap of 60% of project costs. FC with waste heat recovery assigned incentive of $4.00/W.
- Adjusted tiered incentive for CHP fueled by renewable and nonrenewable sources
- All projects have an maximum incentive cap at $2 million per project
- Increased warranty or service contract for 10 years

In 2013 for FY 2014, the CHP FC program was significantly altered to include the following program modifications.[93]

- The categories in which the CHP and FC technologies were organized, and the corresponding incentives, incentive % of project costs, and incentives were all altered, providing more specifications on eligible projects and available incentives.
  - Incentive ranges remained the same – however, the tiered size structure for each technology added specific incentives for sizes.
- For systems >1MW, the maximum incentive was expanded to $3 million, with the incentives as a % of project costs still being applied
- Only natural gas CHP and natural gas or hydrogen Fuel Cell equipment installed on the customer side of the utility meter is eligible
- Raised efficiency requirements for CHP and FC systems w/out waste heat recovery. CHP must have an annual system efficiency of at least 65% (Lower Heating Value – LHV[94]), Fuel Cell systems must achieve at least 50% (LHV), based on total energy input and total utilized energy output. Mechanical energy may be included in the efficiency evaluation.[95]
- Systems must operate a minimum of 5,000 full load equivalent hours per year (i.e. run at least 5,000 hours per year at full rated KW output)
- The Large CHP and FC program were transferred in 2014 for FY 2015 from the EDA to to be managed on an interim basis by Office of Clean Energy staff

The most recent program incarnation has maintained most of the previous changes listed above, with the addition of accepting mixed fuels and 100% renewable – fueled systems, suspension of fuel cell without waste heat recovery eligibility, introduction of technology neutral incentives and elimination of P4P bonus seen in Figure 1-5. Table 1-5 detailed the payment structure once an application is approved.

[91] 2013 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP, November 2012
[92] Based on total energy input and total utilized energy output. Mechanical energy may be included in the efficiency evaluation.
[93] 2014 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP, December 2013
[94] "Higher Heating Value (HHV): refers to the heating value of the fuel and is defined as the total thermal energy available, including the heat of condensation of water vapors, resulting from complete combustion of the fuel versus the Lower Heating Value (LHV) which assumes the heat of condensation is not available". IL TRM v5.0 Vol 2_February 11,2016_Final, page 292 in C&I section
[95] 2014 C&I Energy Efficiency Programs Compliance Filing, TRC, NJCEP, December 2013

Figure 1-5 NJCEP CHP – Fuel Cell Program Incentives as of August 2016[96]

Eligible Technology	Size (Installed Rated Capacity)	Incentive ($/kW)	% of Total Cost Cap per project	$ Cap per project
Powered by non-renewable or renewable fuel source	≤500 kW	$2,000	30-40%	$2 million
Gas Internal Combustion Engine	>500 kW - 1 MW	$1,000	30%	$3 million
Gas Combustion Turbine	> 1 MW - 3 MW	$550		
Microturbine Fuel Cells with Heat Recovery	>3 MW	$350		
Waste Heat to Power*	<1 MW	$1,000	30%	$2 million
	> 1MW	$500		$3 million

The incentive structure is a tiered capacity payment, which means the incentive levels vary based upon the installed rated capacity, as listed in the chart above. For example, a 4 MW CHP system would receive $2.00/watt for the first 500 kW, $1,00/watt for the second 500 KW, $0.55/watt for the next 2 MW and $0.35/watt for the last 1 MW (up to the caps listed).

Table 1-5 Payment Structure

Purchase	Installation	Acceptance of 12 months post-installation data
30%	50%	20%

The payment structure is as follows: 30% is to be paid upfront with proof of purchase for equipment, 50% is to be paid after successful installation and operation of system, and the final 20% is to be paid after acceptance that the project has met performance thresholds based on 12 months of operational data.

There are four stages of a FY17 NJCEP CHP/FC project:

- Preapproval – Initial application and supporting documents are reviewed thoroughly to confirm an effective and eligible system design which meets all program technical requirements, including financial metrics.
- Incentive #1 – Upon equipment purchase, the applicant will receive thirty percent of the total incentive amount committed.
- Incentive #2 – Upon system installation, start up, and submission of as-built data, the applicant will receive fifty percent of the total incentive amount committed.

[96] NJCEP CHP-FC program website http://www.njcleanenergy.com/chp

- Incentive #3 – Upon collection of twelve months of continuous operational data, which demonstrates the system performs as proposed, the applicant will receive the final 20% of the total incentive amount committed.

In order to receive the incentives displayed above projects are approved through a simple payback method. Projects demonstrate they have a simple payback of 10 years or less, including any federal tax credits and the incentive the project would receive through the program. The payback calculation is the total cost to install the system divided by the annual energy savings and the output is expressed in years. For the CHP, the total cost to install the project includes the CHP system and components along with the design, construction, labor, and material cost, a 10-year warranty or service contract cost. It is also necessary to subtract out the CHP Program incentive and any federal tax credits. The annual energy savings is the avoided electric purchase, and also included any additional system fuel inputs.

For the projects listed in Table 1-4, federal tax incentives were not include in the simple payback calculation. For projects going forward, each must demonstrate they have a simple payback 10 years or less, including any federal tax credits and the incentive the project would receive through the program.

This analysis will help in identifying the next steps for the CHP & FC program by reviewing other programs across the countries and summarizing those common practices for potential recommendations.

New Jersey Evaluations

The New Jersey programs supporting CHP and fuel cells have been evaluated over the years. In 2009, an impact evaluation was conducted by KEMA. [97] The evaluation reviewed the four projects[98] that were completed and running during the evaluation period for a total of 1,099 MW in installed capacity and 4.4 GWH of generation. The evaluation provided the following

- More assistance with project feasibility
- Follow up with applicants
- Better access to operational information
- Better outreach on CHP information
- Shorter Approval turn Around
- Shorter Rebate turn Around

recommendations:

Another evaluation was conducted in 2015 by Cadmus[99]. The scope of this evaluation focused on small scale wind, bio power, and fuel cell programs through the NJCEP REIP[100] and CORE[101] programs. More specifically, the evaluation studied seven bio powered CHP, as well as, eight fuel cell projects with heat recovery. All fuel cell projects have been decommissioned by the system owners; the owners reported high costs and unfavorable long natural gas contracts as the reasons for decommissioning.

[97] Combined Heat and Power (CHP) Program Impact Evaluation Final Report, KEMA, NJCEP June 2009. http://www.njcleanenergy.com/files/file/Library/CHP%20Evaluation%20Report%20-%20Final%20June%2010%202009.pdf

[98] Two microturbines, one back pressure steam turbine, and one gas IC engine

[99] Impact Evaluation of Small-Scale Wind, Biopower, and Fuel Cell Programs for the New Jersey Office of Clean Energy, The Cadmus Group Inc., March 2015. http://www.njcleanenergy.com/files/file/Library/NJOCE%20Wind%20Biopower%20Fuel%20Cell%20Evaluation%20Report-03202015.pdf

[100] Renewable Energy Incentive Program

[101] Customer Onsite Renewable Energy Program, ended December 2008

Seven bio-powered CHP projects totaled 4,085 MW of installed generating capacity were reviewed. The evaluation provided the following conclusions were observed for incentivizing bio powered CHP projects:

- Customer were generally satisfied with the installations and incentive process. And expressed an interest to provided future operational data on their systems. But expressed concern on the amount of time it took to process and receive incentives.
- Most of the sites were producing energy that met system expectations
- Complex systems that required varied types of maintenance led to difficulties in with arranging management programs that cover each. Interviewed customers suggested “arranging an independent maintenance program through a variety of contractors”.
- Concerns were expressed with obtaining air permits from DEP, citing the process as a major obstacle in the project process. It was recommended that that process the needed improvement for the future specifically with the treatment of bio power systems as “standard generator”.
- Issues were also articulated regarding the relationship with the local utility, in which they required the biopower system to be removed from grid connection during an outage. Customers cited this should not be the case for some, that these systems are viable for resiliency efforts.

The eight fuel cell projects totaled 1.5 MW were reviewed. The evaluation compiled the following observations and recommendations for fuel cells projects:

Observations:

- Customers cited difficulties with system cost effectiveness:
  - Difficulties experienced with effectively capturing waste heat, Cadmus attributes this to faulty projections. Recovery did not meet customer expectations.
  - Fuel cell stacks need to be replaced 5 to 8 years after installation and operation. This provides challenges for maintenance and capital investments. According to the report, replacing the stack “can cost two thirds more than the price of the fuel cell”. Leading to costs to be well above what was anticipated by customers
- Rebates and energy savings were not enough to cover the expenses
- Incentive process was able to generate interest and investment in the technology.
- Due to the higher than anticipated costs and lower than expected efficiency performance, customers were unlikely to “re-commission” their system.
- “Shortfalls may also have occurred because projections for these systems were misguided, or overly optimistic.
- Systems were not sized properly to meet resiliency or grid independence expectations. Systems were not permitted operate when grid was down.

Recommendations

- Make O&M contracts mandatory for lifetime of system
- Work with utilities to allow systems to operate when grid is down
- Only incentivize fuel cells with heat recovery. Cadmus states that “based on customer testimony, and fuel cell data, fuel cells are only viable when applied in a CHP configuration”.
- Provide more educational support for customers
- Consider providing higher rebate for universities/colleges

2

LITERATURE REVIEW AND COMPARATIVE ANALYSIS

As a part of Phase 1, a literature review and comparative analysis was performed. The purpose is to provide background information and analysis of the programs that support DG technologies. The ultimate objective of this section is to inform recommendations for the Office of Clean Energy staff on how to best provide support for DER through the NJCEP offerings. This analysis will provide information on DG programs across the country, as well as compare and contrast the program parameters with what is currently being offered in the New Jersey's Clean Energy Program (NJCEP) Combined Heat and Power and Fuel Cell program (NJ CHP & FC). A brief history and current status of the program in New Jersey was included in the Introduction to provide context for the comparison and recommendations for potential modifications.

The core of this tasks' analysis is separated into three sections:

Current State of Programs Across the Country → **Review of Technical Studies** → **Review of Common Practices**

The three sections have been organized to provide guidance for a well-informed path forward for the NJ CHP & FC program.

CURRENT STATE OF DG PROGRAMS IN U.S.

This section of the analysis reviews existing and recently expired programs that offer support for CHP related technology across the country. The goal is to provide an accounting of how many and what kind of programs are offered in which states. This accounting will report on program parameters including: program eligibility requirements, technologies included, incentive types and levels, and any available performance data for the programs. While a full matrix of all programs reviewed and each of their full list attributes is included in the Appendix A, this section will highlight prominent programs and program attributes.

Figure 2-1 Type of Financial Incentives for CHP Technology Development

Grants	Loans	Rebates	Tax Credits & Exemptions	Bonds
• Offset the cost elegible technologies • Limit on amount of grant money available in a given soliciation	• Low interest loan with a maximum term • varied rates and terms for loans	• Technical assistence and cash rebate typically offered	• Out of Scope - requires legislative action	• Out of Scope - requires legislative action

There are multiple ways in which financial support can be delivered to promote CHP related technologies as seen above in Figure 2-1, a few of which are out of the scope for NJCEP[102]:

This analysis will focus on grant and rebate programs implemented by state agencies and utility companies that offer financial incentives to CHP related technologies. When designing a program that incentivizes CHP related technologies – there are several components to consider in the program planning process. The important attributes for consideration in program development are described in the figure below.

Figure 2-2 CHP Attribute Consideration for Program Development[103]

Many states and utilities offer incentives for CHP related technologies in some capacity under various types of programs, whether through a general economic development grant, "green community" grant, renewable energy incentive program, custom rebate programs or specific self-generation programs. There are a select number of states and or utilities that explicitly offer targeted incentives for CHP technologies. There are twenty-two current or recently expired programs (excluding New Jersey) that offer incentives, a selection of the reviewed programs are listed below in Table 2-1.

[102] Policies and Resources for CHP Deployment: Financial Incentives, ACEEE, http://aceee.org/sector/state-policy/toolkit/chp/financial-incentives
[103] Portfolio Standards and the Promotion of Combined Heat and Power, Combined Heat and Power Partnership, U.S. EPA, March 2016

Table 2-1 Selection of Current and Recently Expired Programs for CHP Technologies

State	Program Administrator	Program Title	Status[104]
Alaska	State	Renewable Energy Grant Program	Expired
Arizona	Southwest Gas Corporation	Combined Heat & Power Program	Expired
California	State	Self-Generation Incentive Program	Current
Connecticut	State - CT Green Bank	Combined Heat & Power Pilot Program	Expired
Ohio	Dayton Power and Light	Combined Heat & Power Rebates	Current
Illinois	State	Public Sector Combined Heat and Power (CHP) Pilot Program	Expired
	ComEd	CHP Pilot Program	Expired
Maine	State - Efficiency Maine	Custom Distributed Generation Projects	Current
Maryland	State	MEA CHP FY17 Grant Program	Current
	Baltimore Gas and Electric	Combined Heat and Power Program	Current
	Delmarva Power, Pepco	Combined Heat and Power Program	Current - on hold
	Potomac Edison	Combined Heat and Power Program	Current
Massachusetts	State	DOER - Community Energy Resiliency Initiative	Expired
		Mass SAVE - Combined Heat and Power Program	Current
New York	State	CHP Program	Current
		RPS Customer Sited Tier Fuel Cell – Program Small	Expired
		RPS Customer Sited Tier Fuel Cell Program Large	Expired
Pennsylvania	State	Alternative and Clean Energy Program (ACE)	Current – on hold
	First Energy	Combined Heat and Power Program	Current
	PECO	Combined Heat and Power Program	Current
		Smart Ideas: Non-Residential Energy Efficiency Rebate Program	Expired
Rhode Island	National Grid	Combined Heat and Power Program	Current

Program Attribute Review

The following section will discuss several of the programs listed in Table 2-1 in terms of program attributes mentioned Figure 2-2.

CHP System Type and Fuel Use

There is no uniform standard for system type and fuel type inclusion among CHP & FC Programs. Several programs accept all CHP and fuel cell technologies with no distinction in fuel types but others set performance standards or program requirements that essentially eliminate a specific technology and or fuel type.

Programs such as Alaska's Renewable Energy Grant program, Pennsylvania's Alternative Clean Energy Program (ACE), Massachusetts' Community Energy Resiliency Incentive and California's Self Generation Initiative Program (SGIP) offer incentives for a wide range of technologies such as solar PV, wind, geothermal, hydroelectric, CHP, fuel cells, energy storage, and more.

[104] Program status is based on if the program is listed on the utility or commissions website and/or if the program website/documents indicated a specific solicitation period or expiration date. Recently is counted as a program ending in 2015 of 2016.

More specifically, the California SGIP[105] does not make a distinction between eligible fuels for CHP and fuel cells, allowing both renewable and nonrenewable sources. The program does indicate that for CHP and fuel cell systems operating on non-renewable sources that waste heat must be captured for onsite use and or must meet a minimum efficiency requirement of 40%. Fuel cell projects without heat recovery are currently eligible, but must meet a strict greenhouse gas (GHG) threshold. However, in 2016, CPUC Staff recommended the removal of natural gas fueled electric only fuel cell incentive, citing the low cost benefit ratio and failure to meet the GHG emission reduction threshold. [106] Stakeholders were divided on the issue, but ultimately, Staff decided to continue incentivizing electric-only fuel cells because of an updated methodology for calculating GHG reduction that was incorrectly applied.[107] This screening process is explained further in the Project Approval Processes section.

The majority of programs reviewed are targeted at advancing only CHP and FC technology, which include, but not limited to Illinois DECO[108] Public Sector CHP Pilot, Com Ed CHP Pilot, MEA[109] CHP FY17 Grant Program, MassSAVE Combined Heat and Power Program, NYSERDA's CHP program, Rhode Island National Grid CHP program, and several more.

Many other programs make noteworthy inclusions and exclusions regarding these technologies:

- The MEA CHP grant program only allows fuel cell projects that capture waste heat for onsite use.
- Illinois DECO Public Sector CHP Pilot only accepts CHP systems that operate on natural gas and waste heat must be utilized.
- Baltimore Gas and Electric's (BGE) Combined Heat and Power Program accepts CHP reciprocating engines, gas turbines, and fuel cells (w/heat recovery) powered by natural gas and bio gas.
- In Pennsylvania, First Energy's Combined Heat and Power Program accepts applications for CHP using reciprocating engines and combustion turbines using natural gas or biogas with waste heat recovery.
- NYSERDA (New York) provided two separate programs, one for only CHP systems that operate using natural gas or propane and another set of programs for small and large fuel cell programs in which heat recovery is not required.

Efficiency Threshold

Most programs have efficiency requirements that are tied to the total system efficiency[110]. The efficiency requirement is one of the more important program eligibility requirements because it provides a distinct cutoff for whether projects can receive incentives, provides an important comparison point between projects, and is an indicator of potential savings. The table below summarizes the efficiency requirements for the programs reviewed.

[105] Self-Generation Incentive Program
[106] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF
[107] CPUC Staff stated that "as long as a technology is certified to emit less than the first-year emission rate for the program year for which incentives are sought, the technology passes the GHG eligibility screen".
[108] Illinois Department of Commerce and Economic Opportunity
[109] Maryland Energy Administration
[110] Total energy input and total utilized energy output, expressed as either HHV or LHV – difference being HHV considered total available thermal heat, including heat condensation. LHV does not.

Table 2-2 Minimum Efficiency Requirements and Fuel Cell Eligibilty for Current and Recently Expired CHP Programs

State	Program Administrator	Program Title	Minimum Efficiency Requirement[111] (Eff. Req.)	Fuel Cell Without Heat Recovery Eligibility
Alaska	State	Renewable Energy Grant	No minimum stated	Eligible
Arizona	Southwest Gas	Combined Heat & Power Program	Minimum efficiency of 60%, must have waste heat recovery	Not Eligible
California	State - California PUC	Self-Generation Incentive Program	Minimum efficiency of 40% HHV	Eligible
Connecticut	State – CT Green Bank	Combined Heat and Power Program	Minimum efficiency of 50%, must have waste heat recovery	Not Eligible
Ohio	Dayton Power and Light	Custom Rebate Program	Minimum Efficiency of 60% LHV, must have heat recovery	Not Eligible
Illinois	State	Public Sector Combined Heat and Power (CHP) Pilot Program	Minimum efficiency of 60% HHV, must have waste heat recovery	Not Eligible
	Com ED	CHP Pilot Program	Minimum least 60% (HHV) with at least 20% of the system's total useful energy output in the form of useful thermal energy.	Not Eligible
Maine	State - Efficiency Maine	Custom Distributed Generation	Minimum efficiency of 60% LHV, must have waste heat recovery	Not Eligible
Maryland	State	MEA CHP FY17 Grant Program	Minimum efficiency of 60% HHV	Not Eligible
	BGE	Combined Heat and Power Program	Minimum of efficiency 65% HHV	Not Eligible
	Delmarva Power, Pepco	Combined Heat and Power Program	minimum efficiency of 65% HHV	Eligible but ruled out by eff. req
	Potomac Edison	Combined Heat and Power Program	minimum efficiency of 65% HHV	Not Eligible
Massachusetts	State	DOER - Community Energy Resiliency Initiative	No minimum stated, "high efficiency fuel cells allow"	Eligible
		Mass SAVE - Combined Heat and Power Program	*Level 1* - No minimum efficiency, *level 2* - minimum efficiency 60% *Level 3* - minimum efficiency 65%. All must have waste heat recovery	Not Eligible
New Jersey	State	CHP and Fuel Cell Program	Minimum efficiency of 65% LHV (55-59% HHV, depending on fuel)	Not Eligible[112]
New York	State - NYSERDA	CHP Program	Minimum efficiency of 60%	Not Eligible
		RPS Customer Sited Tier Fuel Cell Program Small	Small - <25 kW, annual capacity factor >=50% (actual net annual output/nameplate ratingx8760) actual net annual output = total verified electrical energy delivered by system.	Eligible
		RPS Customer Sited Tier Fuel Cell Program Large	Large >25 kW, annual capacity factor >=50%.	Eligible
Pennsylvania	State	Alternative and Clean Energy Program (ACE) Loan	No minimum stated	Eligible
	First Energy	Combined Heat and Power Program	Minimum efficiency of 65%	Not Eligible
	PECO	Non-Residential Energy Efficiency Rebate Program	Steam Turbine - 80%, Reciprocating Engine - 70%, Gas Turbine - 70%, Microturbine - 65%, Fuel Cell - 55% - must have waste heat recovery	Not Eligible
		Combined Heat and Power	Steam Turbine - 80%, Reciprocating Engine - 70%, Gas Turbine - 70%, Microturbine - 65%, Fuel Cell - 55% - must have waste heat recovery	Not Eligible
Rhode Island	National Grid	Combined Heat and Power Program	Minimum of efficiency of 55% HHV- must have waste heat recovery	Not Eligible

111 Not all programs specified between HHV and LHV

112 Fuel Cell w/out heat recovery incentives have been suspended and currently under review. The previous minimum efficiency requirement without heat recovery was 50%.

A couple programs do not state any minimum efficiencies, whereas other programs go as far as to provide tiered efficiency requirements for the varying CHP technologies. Most programs tend to use a singular minimum efficiency level ranging from 60% to 65% for all technologies which streamlines the application and incentive process. However, the CHP program offered by PECO, sets differing minimum efficiency requirements for the diverse CHP technologies. The tailored minimum efficiencies are to reflect typical technology efficiencies and actual program data received through the PECO custom program.[113]

Most of the programs, except New Jersey, Ohio and Connecticut express the program minimum efficiency level in HHV, rather than LHV. As defined earlier, HHV and LHV express the value of the total thermal energy available, helping to define the efficiency of the system. HHV captures all available heat, including heat from water vaporization, which LHV calculations does not include. An analysis that relies on LHV estimates assume that the heat from water vapor is not recoverable for beneficial use. Such LHV-based analyses would be less appropriate than HHV-based analyses for CHP systems with heat recovery.

Only six of the twenty-two programs reviewed technically allow fuel cells without heat recovery, however three of those programs are more general alternative energy funds that do not state a minimum efficiency requirement. That leaves only the California SGIP and NYSERDA small and large fuel cell programs that incentivize fuel cells without recovery. Most programs either require waste heat recovery, set a high minimum efficiency, or require an economic or environmental screening, which may rule out fuel cell projects without heat recovery. The latter requirement is discussed further in the following section.

Other than New Jersey, no other state or utility program has offered distinct incentives for both fuel cells with and without heat recovery. The two CHP-FC targeted programs offer the same incentive for fuel cells with and without heat recovery. The NYSERDA fuel cell programs have a minimum efficiency requirement of 50%, stating in the program documents that the focus of the program is electrical generation benefits and therefore the recovery of waste heat is not required but recommended due to the benefits.[114] California SGIP allows electric only fuel cells, and only requires a minimum efficiency of 40%, but projects must meet other strict requirements such as greenhouse gas emission standards.[115]

Project Approval Processes

Eligibility requirements also extend to how a project is approved for an incentive. Once a project is deemed eligible to apply to a program based on technology type, size, efficiency, etc the project must go through an approval or evaluation process to assess whether the project will receive an incentive. Similar to the array of technology inclusion options and efficiency requirements, there are also many different approval requirements and processes among programs. The process for New Jersey is outlined in the Introduction section of the Literature Review. Several programs have their approval process available for public consumption, the table below highlights a few of the programs that have stipulated evaluation criteria.

[113] Michael Noreika and Keith Downes, CHP Implementation: Designing Combined Heat & Power Financial Incentives and Eligibility Requirements for Non-Residential Demand-Side Management Programs" Navigant, ACEEE 2013 Summer Study http://aceee.org/files/proceedings/2013/data/papers/6_202.pdf

[114] PON 2157 – RPS Customer Sited Tier Fuel Cell Program – Large Fuel Cell, Program Summary https://www.nyserda.ny.gov/-/media/Files/FO/Current-Funding-Opportunities/PON-2157/2157summary1.pdf

[115] 2016 SGIP Handbook, https://www.selfgenca.com/documents/handbook/2016

Table 2-3 Selection of Reviewed Program's Approval Parameters

State	Program Administrator	Program Title	Program Approval Parameters
New Jersey	State	CHP and Fuel Cell Program	Projects must demonstrate a maximum 10-year simple payback including any federal tax credits and NJCEP incentives
California	State	SGIP	Greenhouse Gas Reduction eligibility screen for fossil fuel projects, among other eligibility requirements
Ohio	Dayton Power and Light	Custom Rebate Program	Payback based on electricity cost savings under 7 years, installed in territory.
Illinois	State	Public Sector Combined Heat and Power (CHP) Pilot Program	Eligible CHP/WHP projects must pass the Total Resource Cost (TRC) test at the "measure" level,
Illinois	Com ED	CHP Pilot Program	Simple payback on the investment is greater than two (2) years (without incentives) Meet the TRC with a score of 1 or greater. Individual projects that score slightly less than 1 on the TRC may be approved by exception at the discretion of the DCEO.
Maine	State - Efficiency Maine	Custom Distributed Generation Projects	Must have 1.0 TRC or higher.
Maryland	State - Maryland Energy Administration	MEA CHP FY17 Grant Program	Be shown in the feasibility study to be cost effective which means that the project's lifetime net energy benefits are at least equal to the cost of the project.
Maryland	Baltimore Gas and Electric	Combined Heat and Power Program	Must have 1.0 BGE's TRC or higher.
Maryland	Potomac Edison	Combined Heat and Power Program	Cost-effectiveness test applied using EmPOWER guidelines
Massachusetts	State	Mass SAVE - Combined Heat and Power Program	Sized to follow thermal loads of the building post implementation of all efficiency measures with a simple payback of 3 years or less. Program administrators run BCA
Pennsylvania	First Energy	Combined Heat and Power Program	Must be evaluated using TRC test
Rhode Island	National Grid	Combined Heat and Power Program	Must have 1.0 TRC or higher. utilizing methodology outlined by RI PUC

In reviewing the programs, many screen each individual project using the Total Resource Cost[116] (TRC) test. A few of the programs supply TRC calculators on the program websites that outline what is included in the TRC calculations. For example, the Public Sector CHP program implemented by Illinois Department of Commerce and Economic Opportunity (DECO) supplies a detailed TRC workbook and evaluation criteria. Those project applications are also evaluated in the following way[117] to provide a holistic look at each application.

- Criteria 1 – Technical Completeness = weight 40%
  - Ex. Ability to reduce BTUs, system efficiency, metering plan, maintenance contract
- Criteria 2 – Financial Completeness = weight 30%
  - TRC ratio, completeness of information in feasibility study, degree to which incentive affects project economics
- Criteria 3 – Applicant Qualifications = weight 20%
  - Background of participants, experience in similar projects, number of systems designed and installed

[116] Total Resource Cost Test is a comparison of program administrator costs and customer costs to utility resource savings
[117] https://www.illinois.gov/dceo/whyillinois/TargetIndustries/Energy/Documents/Final_RFA%20CHP%20Guidelines%207-7-14.pdf

- Criteria 4 – Energy Efficiency of Site = weight 10%
    - Degree to which the applicant shows the energy efficiency of existing building

For the Massachusetts MassSave program, each project must undergo a cost benefit analysis utilizing the methodology set forth by the Department of Public Utilities. The methodology includes the following components[118]:

- The net power (kW) output of the CHP system (net of any incremental parasitic load to operate the CHP system's auxiliary equipment),
- Annual net kWh generated,
- Installed cost of the equipment,
- Ongoing annual maintenance costs,
- Quantity of fuel and type of fuel being fired in the CHP system as well as fuel
- Displaced by the CHP system,
- Timing of the power production, such as winter/summer and peak versus off-peak as
- Defined in the Custom Project application.

Projects must have a benefit cost ratio greater than 1.0 to receive funding. The cost benefit model uses the marginal value of fuel and electricity, value of deferred transmission and distribution, value of capacity (determined by ISO New England Peak Period definitions), O&M costs annualized over the list of the unit and the total cost paid for the system minus any federal tax credits or grants. What is not included are the federal Modified Accelerated Cost Recovery System (MARCS) corporate depreciation and Massachusetts Alternative Portfolio Standard (APS). Similarly, National Grid's program in Rhode Island does allow the use of federal tax credits and grants in CBA calculations, but does not allow any state related funding (i.e. indirectly funded by the systems benefit charge) or MARCS into the calculation. In contrast, the Illinois DECO program described above calculates the CBA using the installed system cost *before* federal tax credit are applied.

The process in California diverges from the other programs reviewed. Projects are evaluated primarily based on four main criteria, with the fifth and sixth considered as "soft" requirements.[119]

1. Lower GHG emissions
2. Lower or shift peak load to off-peak
3. Be safe and commercially available
4. Reduce criteria air pollutants
5. Societal benefits. Technologies should provide a net benefit to society, as measured by the Societal Total Cost (STC) test[120], or have the potential to do so
6. Market transformation. Technologies should demonstrate the possibility of becoming self-sufficient, or attaining market transformation

Fossil fuel emitting projects need to pass a GHG emission reduction screening. Projects have to emit less than a GHG emission rate eligibility threshold (CO2 per MWh) set by the Commission

[118] http://www.masssave.com/~/media/Files/Business/Applications-and-Rebate-Forms/A-Guide-to-Submitting-CHP-Applications-for-Incentives-in-Massachusetts.pdf
[119] CPUC Decision 16-06-055 June 23, 2016
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF
[120] Societal Cost Test is a comparison of society's costs of energy efficiency to resource savings and non cash costs and

(CPUC). [121] Projects “must emit GHGs at a rate less than the adopted GHG emission [rate] when averaged over a ten-year period and assuming annual performance degradation of 1%”. [122] The goal of the program is to reduce GHG emissions through more efficient on-site customer generation, therefore the approval process aligns with the program goal.

Incentive levels

The incentives among programs vary considerably, not only in the amount of the incentive, but also the type of incentive (production incentive, one time capacity rebate, design incentive, etc) and the components surrounding the incentive (maximum caps, % of installed costs, size limits, adders (for fuels, locations, suppliers)). The complexity of the incentive structure also varies drastically. Some programs have simple one time capacity rebates for all technologies with no additional bonuses, such as the Maryland Energy Administration’s grant program offering $425-$575/kW (depending on system size). This simple structure differs from other programs with complicated tiered incentive structures that decline with size, offering a combination of capacity and performance based incentives (i.e California’s SGIP).

Programs also can offer specific incentives for the different stages of CHP design and installation. ComEd’s CHP Pilot Program and BG&E’s CHP Program offer incentives for the design stage, installation, and production stages of CHP installations. These different incentive stages cover feasibility studies, planning consultants, interconnection fees, and finally the ability of the system to produce efficiency energy.

Table 2-4 describes the incentive structure options for providing financial support for CHP installations.

[121] CPUC Decision 16-06-055 June 23, 2016
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF
[122] Ibid

Table 2-4 Description of Incentive Structure Types[123]

Incentive Type	Payment Unit	Performance Component?	Advantages	Disadvantages
Capacity	$/MW	No	• Low administrative burden • No system performance calculation	• Incentive disregards system performance
Energy Generation	$/kWH	Varies	• Low administrative burden for calculating expected annual energy production	• Generation predictions do not always reflect actual • Incentive typically disregard system performance
Project Cost	N/A	No	• Low administrative burden • No system performance calculation	• Project costs can be very high • Incentive disregards system performance
Tiered Capacity	$/MW	No	• Reduced relative incentives for large installations	• Incentive disregards system performance
Tiered Capacity w/performance	$/MW & $/kWh	Yes	• Reduced relative incentives for large installations • Increases utility security by incentivizing performance	• Difficult to administer
Hybrid capacity/ performance	$/kWh & $/MW	Yes	• Creates unique incentive for each project • Reduced relative incentives for large installations • Increases utility security by incentivizing performance	• Difficult to calculate and administer • Performance period can last several years

As the complexity of the incentive structure increases, so does the need to provide education for customers. Complex incentive structures require a large administrative effort to educate customers on what is eligible, the application process, the potential incentive payments they could receive, etc. State regulators and utilities have to balance the complexity of the incentive structure with ensuring that the program is approachable and that projects receive adequate incentives[124]. Additionally with complex incentive structures, there need to be adequate review and approval process from utilities and regulators.

Table 2-5 provides details on the incentive structure for a selected number of programs reviewed.

[123] CHP Implementation: Designing Combined Heat and Power Financial Incentives and Eligibility Requirements for Non Residential Demand Side Management Programs, Michael Noreika and Keith Downes – Navigant, Michael O'Leary and Jordan Stitzer, PECO Energy, ACEEE 2013 Summary Study on Energy Efficiency in Industry

[124]Ibid

Table 2-5 Incentive Structures for a Selection of CHP Programs

State	Program Administrator	Program Title	Incentive Structure Type	Incentive Structure
California	State - California Public Utilities Commission	Self-Generation Incentive Program	Tiered Capacity w/ performance incentive	Incentive per W capacity system. Projects >30 kW receive 50% of incentive at completion, remaining 50% as performance incentive for 5 years step 1 - $0.60/W & w/ bio gas $1.20; step 2 -$0.50/W & w/ bio gas added $1.10; step 3 - $0.40/W & $1 w/bio gas added Adder incentive of 20% is available for the installation a California supplier.
Illinois	State	Public Sector Combined Heat and Power (CHP) Pilot Program	Project cost payment w/ performance	Design incentive: $75/kW Capacity Construction Incentive: $175/kW Capacity Performance Incentive: $0.08 (>= 70% HHV), $0.06 (60%<n<70% HHV) per kWh based on 12 months of metered data Total incentive is capped at $2,000,000 or 50% of project cost, whichever is less.
Maryland	State - MEA	MEA CHP FY17 Grant Program	Tiered Capacity payment	Grant, first come first serve, range from $425/kW to $575/kW (based on the system size), capped at $500,000/ project.
	Baltimore Gas and Electric	Combined Heat and Power Program	Project cost payment w/ performance	Design incentive ($75/kW) Installation incentive $275/kW for projects under 250kW; $175/kW for projects 250 kW or greater) Performance ($0.07/kWh for 18 months) Capacity, performance incentives each capped at $1.25 mil.
Massachusetts	State Mass SAVE	Mass SAVE - Combined Heat and Power Program	Tiered Performance incentive	Incentives range from $0.075 to $0.115 per annual kWh generated. Tiers delineated by >= or < 150 kW system size and efficiency level. Incentives may not exceed 50% of total project cost.
New Jersey	State	CHP & Fuel Cell Program	Tiered Capacity Payment	Incentive vary by system type and size. Incentives range from $350 per kW to $2000/kW. Incentives capped at 30-40% of total project cost. Cap per project range from $2-3M depending on system type.
New York	State- NYSERDA	CHP Program	Tiered Capacity Payment	Base incentives based on nameplate capacity for upstate and downstate. For example <50kW = $1,000/kW upstate, $1,200 downstate. Apstates10 % bonus for critical facilities, 10% bonus for targeted zone. Base incentive capped $2.5M including bonuses per project
		RPS Customer Sited Tier Fuel Cell Program Small	Performance Incentive	$0.15 per net kWh produced for sites with an annual capacity factor <=50% for 3 years after commissioning, max of $20,000 per year per project site, total cap of $50,000/project
		RPS Customer Sited Tier Fuel Cell Program Large	Hybrid Capacity and Performance Incentive	Phase 1 funds - grid parallel installations even if not island capable = $2,000 per kW up to $600,000. Phase 2 funds for project sites that upgrade to island before end of 3rd performance period= $3,000 per kW of installed capacity or the remainder of the total project cap ($1 million per installation), whichever is less.
Pennsylvania	PECO	Non-Residential Energy Efficiency Rebate Program	Capacity Payment w/performance incentive	Eligible for up to $1 million, or no more than 50% of total costs. First 500 kW = $300kW, 500kW-1.5MW=$150/kW The performance incentive for CHP projects is $0.02/kWh based on the actual electricity generated
Rhode Island	National Grid	Combined Heat and Power Program	Tiered Capacity Payment based on Efficiency	Tier 1 $900/Net kW for CHP with annual efficiency >55% and <60% Tier 2 $1000/Net kW for CHP with annual efficiency > or equal to 60%, Tier 3 Reduce the site energy use at least 5% or- $1,125/kW for annual efficiency >55% and <60% Tier 4 Reduce the site energy use at least 5% - $1,250/kW for > or = to 60% annual efficiency. All incentives will not exceed 70% of the installed cost

The NJ CHP & FC program, similar to other programs, provides a declining capacity incentive structure as system size increases. The NJ CHP & FC program has one of the lower percentage of project cost caps (30-40%) but offers a higher dollar per project cap ($2-$3 mil). National Grid Rhode Island provides a maximum of 70% of project cost with no dollar per project cap, whereas the Illinois state program caps incentives at $2 million or caps incentives at 50% of project costs cap (whichever is less). Incentives in NJ are generally higher than incentives offered by PECO, Maryland, and California. NYSERDA and National Grid incentives are more in the range of the NJ CHP & FC incentives.

A closer look at the incentive structures for programs that offer incentive for fuel cells without heat recovery is provided below.

California

The program in California was created by the California Public Utilities Commission (CPUC) 2001 to initially address peak load reduction.[125] The program is directed by the CPUC and administered by the individual major investor owned utilities (IOUs).[126] The program distributes tiered capacity payments with performance incentives. For projects less than 30 kW, 100% of the total incentive is paid upfront. Projects over 30 kW, 50% of the incentives is paid upfront and 50% is paid through performance incentives for 5 years. The CPUC just recently adopted major programs changes which include - 75% of the total program budget is allocated towards advanced energy storage, 25% is allocated towards the remaining generation technologies (40% of that carved out for renewables).[127] The program is now pushing to promote advanced energy storage more, separate incentives for that technology are detailed in a recent CPUC decision.[128] A revised incentive structure for the generation technologies is included below:

Table 2-6 Current CA SGIP incentives (Approved June 2016)[129]

	Step 1		Step 2		Step 3	
	Incentive/W capacity	Max Incentive w/Biogas Adder	Incentive/ W capacity	Max Incentive w/Biogas Adder	Incentive/ W capacity	Max Incentive w/Biogas Adder
Wind[130]	$0.90	n/a	$0.80	n/a	$0.70	n/a
Waste to Heat	$0.60	n/a	$0.50	n/a	$0.40	n/a
Pressure Reduction Turbine	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Internal combustion CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Microturbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Gas Turbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Fuel Cell CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Fuel Cell Electric Only	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00

[125] 2013 SGIP Impact Evaluation, Itron, The SGIP Working Group, April 2015
[126] Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and San Diego Gas and Electric (SDG&E)
[127] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF
[128] Ibid
[129] Ibid
[130] Note that 40% of the incentives in each step shall be reserved for renewable generation technologies, meaning that natural gas fueled technologies may see their incentives decrease to a lower step while renewable technologies may remain at a higher step if they have not met their 40% carve out. (Ibid) Higher incentive for higher cost RE technology.

The step design is devised to "step down" incentives throughout the payment process; "whereby specific quantities of incentive budget are allocated to specific incentive levels, with incentives declining upon full reservation of the budget at a previous incentive step"[131]. Incentives are higher for wind, but are the same for the remaining generation technologies. This is a departure from previous incentive structure that was not technology neutral.

New York

NYSERDA manages and implements the programs that offer incentives for CHP and FCs. Currently there are three programs or funding opportunities: CHP Program, Small Fuel Cell Program, & Large Fuel Cell Program.

CHP PROGRAM

Base incentives based on nameplate capacity with the maximum incentive for any one project is capped at $2.5M including bonuses. There is one 10% bonus available upstate, and two 10% bonuses available downstate. The bonuses are calculated on the total base incentive (generator + chiller+ ORC).

Table 2-7 Current NYSERDA CHP Program Incentives

CHP System Size	Upstate Incentive	Downstate Incentive
Induction up to 50kW	$1,000/kW	$1,200/kW
Less than 100kW	$1,500/kW	$1,800/kW
100kW to 1500kW	$(1,550 – size/2)/kW	100-1,200 kW = $(1,850 – size/2)/kW
1500kW to 2400kW	$1.2M	-
2400kW to 3000kW	$500/kW	1,200 – 3,000 kW = $1.5M
Over 3MW	$500/kW	$500/kW
Chillers	$600/ton	$750/ton

The incentives are scheduled to decrease by 5% of the original amount on September 1, 2016, March 1, 2017, and September 1, 2017 for systems 50 kW - 3MW. Incentive reductions for CHP systems 50kW and smaller have not been established at this time. CHP Systems larger than 3MW will not be eligible after 12/31/2016.

FUEL CELL PROGRAMS

Similar to what New Jersey offers, NYSERDA supplies two separate funding opportunities for small and large fuel cells.

For small fuel cell projects (< = 25 kW), performance incentives are offered on a first come first serve basis till fully committed or expiration date. For large fuel cell projects (>25 kW), a combination of capacity and performance incentives are offered on a first come first serve basis until expiration date or funds are fully committed. As now, these two funding opportunities have expired as of February 2016. The incentives are summarized in the below table.

[131] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

Table 2-8 Current NYSERDA Fuel Cell Program Incentives

Program	System Size	Incentive Type	Incentive	Project Funding Caps
RPS Customer Sited Tier Fuel Cell Program Small	<= 25 kW	Performance Incentive	• $0.15 per net kWh produced for sites with an annual capacity factor <=50% for 3 years after commissioning	• Max of $20,000 per year per project site • Total cap of $50,000/project site
RPS Customer Sited Tier Fuel Cell Program Large	>25 kW	Hybrid Capacity and Performance Incentive	• Phase 1 funds - even if not island capable = $2,000 per kW o 25% of incentive when sit is operational & commissioned by NYSERDA o 75% of incentive in 3 equal annual payments to sites operating at a <=50% capacity factor • Phase 2 add'tl funds for project sites that upgrade to island before end of 3rd performance period= $3,000 per kW of installed capacity or the remainder of the total project cap	• Phase 1 = up to $600,000. • Phase 2 $1 million per installation

For small projects, the incentive is more straightforward. There is a performance incentive supplied for three consecutive years after commissioning for sites that can achieve an annual operating capacity factor of 50% or greater. Incentives are capped per project and per year. For larger systems, the structure is more complicated. One capacity payment (25% of max incentive) is offered when system is installed, operational, and commissioned. Three equal consecutive payments (each 25% of max incentive) are offered as a performance incentive for systems that operate with an annual capacity of 50% of greater. Systems will also receive an additional capacity payment if systems become island capable, i.e. grid independent operation/standalone systems.

Program Participation

Participation data is available for several programs. The data shows that some programs are highly successful, while others struggle to obtain participants. California and New York have project databases available to the public, while for other states and utilities program performance data is a bit more difficult to find – typically buried in annual reports.

Table 2-9 Participation Data for Available Programs

Utility	Participation Data
Southwest Gas	No participants in 2015, program has been suspended.[132]
BGE, Delmarva and Pepco	2014 BGE incentivized 5 projects for 20,036 MWh and 2.860 MW in generation and demand.[133] No projects completed in 2015. Approved projects are expected to be completed in 2016-2019.
MassSAVE	As of 2012, 25 projects incentivized, total capacity of 5.44 MW that produced 33,008 MWh in annual electricity generation and 2.99 MW in summer demand savings.[134]
Connecticut Green Bank	As of 2015, incentivized 0.6 MW of biomass, 4.6 MW of conventional CHP, and 14.8 MW of fuel cell installed capacity[135]
PECO	As of May 2014, 7 CHP projects totaling $3.6 mil and represents 9.5 MW of capacity and over 56,000 MWh in net energy generation.[136]

In New York, NYSERDA maintains a comprehensive DG Integrated Data System that monitors the performance data for all the DG projects installed through the NYSERDA programs. The website provides detailed information on all projects, maps of DG locations, and up-to-date hourly system performance data[137]. While real time data is useful in tracking program performance and providing performance based incentives, it is important to note that this level of tracking requires a significant amount of program resources to implement equipment (or require installation as a part of program), process and monitor data, and to provide an interactive interface. Other states to track and monitor operational data to provide performance based incentives, but it is typically on the annual basis. The table below shows the installations incentivized by the NYSERDA programs as of September 19, 2016.

Table 2-10 Current status of installations in NYSERDA Portfolio (September 2016)

DG Technology	Number of Commissioned Projects (Power Units)	% of Total Projects
Combined-Cycle Gas Turbine	0	0%
Fuel Cell	10	7%
Microturbine	37	25%
Reciprocating Engine	95	64%
Simple-Cycle Gas Turbine	2	1%
Solar PV	4	3%
Steam Turbine	1	1%
Wind Turbine	0	0%
Total	**149**	**100%**

Nine of the ten fuel cell projects commissioned recover waste heat for hot water.

[132] Arizona Energy Efficiency and Renewable Energy Resource Technology Portfolio Implementation Plan, Program Year 4 Annual Program Report June 1 2015 – December 31 2015, Southwest Gas,
[133] Energy Efficiency, Conservation and Demand Response Programs, Semi Annual EmPOWER Maryland Utility Filings, Order NO. 87285 December 2015
[134] Massachusetts Combined Heat and Power Program Impact Evaluation 2011-2012, Massachusetts Energy Efficiency Program Administrators, KEMA, November 2013
[135] Connecticut Green Bank Comprehensive Annual Financial Report Fiscal Year Ended June 30, 2015,
[136] Combined Heat and Power En Banc Hearing Presentation, PECO Energy, May 2014 http://www.puc.state.pa.us/NaturalGas/pdf/CHP/PPT-PECO_EBH050514.pdf
[137] NYSERDA DG Integrated Data System http://chp.nyserda.ny.gov/home/index.cfm

The California SGIP has been the most successful program thus far. The program supplies a detailed listing of projects that have applied through the programs. The table below presents the technology installation incentivized by the SGIP.

Table 2-11 Current status of installations in CA SGIP (September 2016)

Primary Mover	Number of Installations	Sum of Rated Capacity [kW]	% of Total Equipment Type
Alternative Energy Storage	603	8,158	28%
Fuel Cell CHP	86	31,500	4%
Fuel Cell Electric	93	43,630	4%
Gas Turbine	11	30,845	1%
Internal Combustion	253	154,889	12%
Microturbine	143	25,029	7%
Photovoltaic	920	144,311	43%
Wind Turbine	16	12,572	1%
Total	**2,125**	**450,933**	**100%**

Of the technologies requiring fuels almost 80% are powered by natural gas, 3% by biomass, 9% digester gas, and 9% by landfill gas. Of fuel cells, 7% are powered by biomass, 16% by digester gas, 20% by landfill, and 57% by natural gas.

REVIEW OF TECHNICAL STUDIES

A number of states have taken a closer look at how DG technologies are evaluated using cost benefit analysis and how those methodologies may fail to capture the full value of DG relative to the full benefits of DG. Of particular note in the two technical studies reviewed here is the preference for the Societal Cost Test as the best indicator of cost efficiency for DG technologies although some exceptions may be needed. The technical studies reviewed in this section describe how some of the programs discussed in the previous section are reviewed for cost effectiveness. This section will review two of the most recent cost benefit analyses from states that have successful CHP programs. The review will consist of a summary of the following technical studies:

- New York*: Benefit Cost Analysis for Distributed Energy Resources* prepared for the Advanced Energy Economics Institute as a part of the New York Public Service Commission's Reforming the Energy Vision (REV) and the Clean Energy Fund proceedings by Synapse Energy Economics in September 2014[138]
- California: *2015 Self-Generation Incentive Program Cost Effectiveness Study* submitted to PG&E and The SGIP Working Group prepared by Itron in October 2015 [139]

The review will cover a brief background of the report for context purposes, a summary of the study results and recommendations, and the key findings that can be useful for New Jersey for the purposes of this analysis.

[138] http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf
[139] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

NEW YORK

Background

The Benefit Cost Analysis for Distributed Energy Resources Study by Synapse Energy was prepared for the Advanced Energy Economic Institute (AEEI). The AEEI is a non-profit organization aimed at increasing opportunities and awareness for the advancement of energy. The organization has been actively involved in New York's REV proceedings where DER has played a key role. The objective of the benefit cost analysis (BCA) for the DER study is to highlight the important considerations when assessing the cost effectiveness of the DER. The end goal of the study was to provide information and analysis for the development of a benefit cost analysis framework for the REV proceedings to help with utility resource planning, pricing, and procurement of DER. The application of the CBA is discussed in broad high level terms and is not discussed relative to specific DG project applications.

Several policy goals were identified by the New York Public Service Commission (NYPSC) as important for the assessment and implementation of DER: "enhanced customer empowerment, market animation[140], system wide efficiency, fuel and resource diversity, system reliability and resiliency and reduction of carbon emissions".[141] The state has historically relied on the Total Resource Cost[142] (TRC) test, however the NYPSC and other stakeholders have expressed concerns that the test does not reflect the important attributes of DER and the policy considerations listed above.

Summary

As a part of the REV process, a closer look was taken at what benefit cost tests were used to assess DER programs or portfolios. The study details the standard energy efficiency screening tests, explaining the components and implications of each of the tests. One of the main issues discussed is the ineffectiveness of the Total Resource Cost test (TRC) to capture non energy benefits[143] and the full range of relevant DER costs and benefits, which the NY Department of Public Service Staff (Staff) has emphasized as a requirement to a revised BCA framework.

The TRC test was suggested as being "too narrowly defined and does not account for a sufficient range of non-energy benefits. According to the report, this question does not address the costs and benefits to society as a whole, only the relevant participants and non-participants. The report summarizes and addresses a straw proposal on DER Benefit Cost Analysis developed by Staff in 2014. The straw proposal puts forth recommendations for a BCA framework, specifically recommending the use of the Societal Cost Test (SCT), Utility Cost Test (UTC or PAC)[144] and Rate Impact Measure test (RIM)[145] in reporting BCA results. The straw proposal also highlights the need to include particular hard-to-quantify benefits that have been typically excluded from the current use of the TRC test in New York: these include "reducing the state's vulnerability to fuel

[140] "At the retail level, adoption of DERs increases the number of market actors involved in supplying energy products and services, facilitating both competition and innovation." Benefit Cost Analysis for Distributed Energy Resources Synapse Energy Economics in September 2014

[141] Benefit Cost Analysis for Distributed Energy Resources Synapse Energy Economics in September 2014

[142] Total Resource Cost Test is a comparison of program administrator costs and customer costs to utility resource savings

[143] Non energy benefits defined as "including benefits other than direct cost savings and demand reduction/system benefits, e.g. employment opportunities, effect on low income customers, effect on housing stock, environmental justice implications, or environmental benefits other than those generally attributable to energy efficiency improvements"!(NY PSC 2008, App.3)

[144] Utility Cost Test or Program Administrator test (PAC) is a comparison of program administrator costs to supply side resource costs

[145] Rate Pater Impact Measure comparison of administrator costs and utility bill reductions to supply side resources costs.

shortages, job creation, improving energy price stability and reducing air emissions and other environmental damages”.[146]

In the report, Synapse agrees with Staff and also recommends the use of the SCT as the primary test to assess the cost effectiveness of DER because it is able to account for more of the energy policy goals listed above that are important to the NYPSC. Itron also suggests the use of the UTC to be reported, but not to be used in isolation for decision making. The report explains that the UCT does consider utility impacts related to utility system costs and average customer bills, which would likely be reduced due to increased installation of DER. However, the test does reflect DER participant impacts with respect to non-electric fuel savings or low income benefits, and other utility related impacts that are hard to quantify like improved reliability and increases customer engagement. The Rate Impact Measure (RIM) test was recommended to be reported also, but not be used to assess DER rate impact. This is because it does not provide a useful assessment of actual rate and equity impacts, and is not the lowest cost option for customers. The report acknowledges that DERs can have mixed effects on rates; rates can be increased to recover DER program costs from all customers or “lost revenues”[147] and/or reduced due to reduced transmission and distribution costs. These differing rate impacts complicate the application of the RIM test, and the report advises to proceed with caution and to fully understand the cost recovery mechanisms when calculating the RIM test for DERs.

The report details the impacts of DER on relevant parties and perspectives of interest. The perspectives of interest within a benefit cost analysis are considered to be 1) all utility customers, 2) participants, 3) society as a whole. The recommended focus is to examine system costs and benefits to “all utility customers” because DER impacts not only the program participants, utilities, and system operators, but utility ratepayers in general. The costs and benefits from each of the perspectives are detailed for the following DER categories: energy efficiency, demand response, distributed generation and distributed storage. For distributed resources, the following are a few of the important costs and benefits from each perspective:

DG Costs

- Utility customers – program administration costs, integration costs (distribution system & ancillary services), platform costs (advanced distribution system management, capital and operating expenses)
- Participants – participant non energy benefits (low income specific[148], tax credits, participants utility savings ex. Time dealing w/billing, property improvements etc., property improvements)
- Society – public benefits (economic development, tax impacts on public benefits), avoided air emissions

DG Benefits

- Utility customers load &demand reduction & avoided costs, avoided compliance costs, avoided ancillary services (operating reserve), market efficiency (customer empowerment, animation of retail market for DER), risk (resiliency portfolio risk)
- Participants – direct costs (capital costs of installations, transaction costs, annual O&M)
- Society – state tax credits, federal tax credits

[146] Benefit Cost Analysis for Distributed Energy Resources Synapse Energy Economics in September 2014

[147] Lost revenues:” the effect where DERs reduce electricity sales and prevent the distribution utility from recovering the amount of revenues it would have otherwise recovered” Ibid

[148] Low income specific refers to the potential benefits from reduced energy costs and for owners of low income rental properties that might invest in distributed generation could reduce costs, and improve reliability.

The report acknowledges that many of the cost and benefit components listed above are hard to quantify, but recommend that they should be addressed and included using alternative approaches including:

- Proxies – avoided cost multiplier, electricity multiplier, and other multipliers
    - Relevant for DG impacts: Resiliency, portfolio risk, project risk, low income specifics, participant utility savings, participant direct costs
- Alternative screening benchmarks – regulators can choose an alternative benchmark, besides the traditional screening of cost effectiveness ratios greater than one. Typically used for many low income programs, the ratio threshold is lowered for programs or projects that have significant non energy benefits.
- Regulatory judgement - when regulators make an investment decision about a program without having all the impacts quantified and/or having a pre-screening benchmark. Judgement to be applied with more flexibility and on a case by case basis. Recommended to still have decision protocols involved, i.e. limited to certain resources, or impacts like job creation), or applied for a limited amount of time until other methods are developed
- Multi-attribute decision analysis – a matrix created with available data on each option's (program or project) attributes, weights are assigned to each attribute relative to its importance to decision makers.
    - Relevant for DG impacts: customer empowerment, animation of retail market for DG, economic development, other natural resource impacts

The report further discusses other important aspects of BCAs, such as accounting for risk and selecting discount rates. New York utilities use a discount rate based upon a utility's weighted average cost of capital for evaluation, which leads to a relatively high discount rate that places less value on long term costs and benefits. Synapse recommends the use of a societal discount rate in the range of zero to three percent real because it is "best able to reflect the time preference associated with the state's energy goals, many of which are related to social impacts."

Table 2-12 State Discount Rates by Primary BCA Test

Primary Test	**UCT**	**TRC**					**SCT**	
State	CT	NY	NH	RI	MA	DE	VT	DC
Basis for Discount Rate	Utility WACC	Utility WACC	Prime Rate	Low Risk 10 yr Treasury	Low Risk 10 yr Treasury	Societal Treasury Rate	Societal	Societal 10 yr Treasury
Current Rate (Real)	7.43%	5.50%	2.46%	1.15%	0.55%	TBD	3.00%	1.87%

Key Findings

- The Total Resource Cost test (TRC) although commonly used was found to be ineffective in capturing non energy benefits and the full range of relevant DER costs and benefits,.
- Recommends the use of the Societal Cost Test when evaluating the cost effectiveness of DER due to the ability to value non energy benefits that are vital benefits for DER
- It is highly important and possible to consider "hard to quantify" impacts for DERs through alternative accounting methods

- Recommends the use of a societal discount rate to appropriately consider the long term and short terms costs and benefits of DER

CALIFORNIA

Background

The program in California was created by the California Public Utilities Commission (CPUC) in 2001 to initially address peak load reduction.[149] The program has subsequently expanded its scope to include the goals of reducing greenhouse gases, improving reliability, reducing customer electricity purchases and transforming the DER market. The program is directed by the CPUC and administered by the individual major investor owned utilities (IOUs).[150] The technologies incentivized by the program include wind, waste-to-heat, pressure reduction turbine, internal combustion turbine –CHP, microturbine-CHP, gas turbine-CHP, advanced energy storage, and fuel cells (CHP & electric only). The program distributes tiered capacity payments with performance incentives for larger projects.

The report that is reviewed for this analysis is the 2015 SGIP Cost Effectiveness study prepared by Itron. The goal of the study was to assess the cost effectiveness of technologies the program incentivizes during the time period of 2014-2034.

The report addresses the following questions:

- Who pays for the resource being deployed and who benefits?
- What are the primary components of reduced costs or increased benefits?
- Are SGIP-related technology costs expected to drop or increase over time and to what extent?
- How will changes in energy market conditions or policies affect the cost effectiveness of SGIP technologies?
- Can the level of incentives provided to one SGIP technology impact the economic viability of other SGIP technologies and does that overly affect market competition?

Summary

The scope of the study is quite large, where the study assesses the cost effectiveness 15 different technologies with 31 unique combinations of configurations and fuel types[151]. The report presents results from the perspective of all utility customers (participants and non-participants) through the TRC test, society through the SCT, and participants through the PCT and program administrations (PACT)[152]. The assessment leaves out the RIM test citing a decision in 2009 by the CPUC to remove it from cost effectiveness decisions due to the inability of the test to capture the total costs of DG.[153] For the study, the TRC and SCT are calculated with the same inputs, except for the discount rate. The discount rate applied to future costs and benefits in the TRC is 7.5% (utility's discount rate), while the SCT uses 5% (societal discount rate). For screening purposes, a threshold of 1.0 was used for the TRC and SCT. The SCT is considered as the primary cost effectiveness test used to assess technologies as a whole. The screening of projects for incentives is done separately and not used as a primary screening for project approval.

[149] 2013 SGIP Impact Evaluation, Itron, The SGIP Working Group, April 2015

[150] Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and San Diego Gas and Electric (SDG&E)

[151] Excluding solar PV, which is analyzed in a different cost effectiveness study for the CPUC.

[152] Same as the Utility Cost Test

[153] see D.09-08-026, pg. 25, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/105926-03.htm#P198_40260

The analysis developed learning curves to estimate dynamic future technology costs. Many of the DG technologies will continue to advance in performance and cost, such as advanced energy storage and fuel cells, therefore California finds it important when looking out 20 years to include a component that addresses those technology costs changes. Other critical inputs to the assessment include fuel consumed, nominal rated capacity, annual capacity factor, efficiencies, useful waste heat recovery, annual degradation rates, critical costs (capacity equipment costs, O&M, pollution controls, standby rate, interconnection fees), and critical benefits (avoided grid costs, bill and energy savings, rebates and incentives, net energy metering bill credits, environmental benefits, reliability). Below is a brief description of the assumptions for several critical benefit inputs:

- Bill and energy savings – For modeling systems that recover waste heat, it was assumed that waste heat replaced the gas that would have been used for heating water in a boiler with 80% efficiency. Both electric and gas bill savings are projected using electrical efficiency, capacity factors, useful waste heat rates and electricity/gas rates.
- Environmental benefits are captured through avoided environmental emissions accounted for in the avoided cost calculations[154]. The avoided emissions are from the 1.) the net difference between emissions produced from the SGIP system and emissions produced from the grid, 2.) the use of recovered waste heat by CHP systems offsets the need to produce thermal energy from onsite boilers.
- Reliability benefits – these benefits are also addressed in the avoided cost model, which assumes reductions in demand caused by SGIP systems have at least roughly the same reliability impacts as changes in demand caused by energy efficiency.

The following are key results from the analysis in 2020:

- "Nearly all (18 out of 26) of the evaluated SGIP technologies pass the lower SCT benefit-cost ratio of 0.8 by 2020.
- SGIP technologies with an SCT benefit-cost ratio less than 0.8 in 2020 include microturbines fueled by natural gas or directed biogas, fuel cells with CHP capabilities fueled by natural gas or directed biogas, the electric-only fuel cells regardless of the fuel source; and the large storage (5 MW) technology.
- Eight of the evaluated SGIP technologies had SCT benefit-cost ratios greater than 1.0. Factors that contribute to these high STRC benefit-cost ratios include no fueling costs, favorable tax treatment, and additional revenue streams (e.g., Renewable Energy Credits)".[155]

Those technologies that have a SCT greater or equal to 0.8 are technologies that can be viewed as important to society in several years. In comparing the results of the SCT to the PCT, the report identified several technologies that have a high value to society in 2020, but are currently facing high market barriers. Those include:

- The 500 kW IC engines regardless if fueled by natural gas, directed biogas, or onsite biogas; and the 1.5 MW IC engines fueled by natural gas or directed biogas.
- Both the 2.5 MW and 7 MW gas turbine, if fueled by natural gas, or directed biogas.
- The 500 kW CHP fuel cell fueled by onsite biogas.
- The 30 kW AES and the 1.5 MW wind energy technologies.

[154] The monetary values for emissions are derived from the E3 Avoided Cost Model dated May, 21 2015. The cost of carbon in this model is based on CO2 prices from the 2014-2030 CPUC MPR Forecast. In 2014, the CO2 price is $22.50/ton, increasing to $36.97/ton in 2020. The NOx price is $6.40/lb in 2014 and $12.47/lb in 2020.
[155] 2015 Self-Generation Incentive Program Cost Effectiveness Study, Itron, March 2015

California SGIP Impact Evaluation

To further supplement the knowledge surrounding the SGIP in California, an impact evaluation for the program was reviewed. In 2015 an impact evaluation was released for the California SGIP aimed at quantifying impacts for the program in the 2013 calendar year. Reviewing the impact evaluations can provide insight into what has worked for the program and state, and what has not.

At the end of 2013, internal combustion engines, microturbines, and fuel cells (CHP and electric only) were among the most installed projects. The majority of cumulative incentives paid have been to fuel cell projects, more specifically electric-only fuel cell projects. Total reported eligible project costs are the highest for electric only fuel cells and electric only fuel cell projects generated the most electricity. All of this indicates that fuel cells in general are a popular and successful technology in California. However, electric-only fuel cells are reported as the most expensive technology, and dominate the total SGIP incentives paid out to customers (45% of total paid SGIP incentives).

The cost benefit analysis for the SGIP program completed in 2015, discussed earlier in the section, indicates several fuel cell configurations are not cost effective for incentives. Electric only fuel cells, fuel cells CHP with natural gas, and fuel cell CHP with direct bio gas all fell below 0.80 in the SCT test. Only fuel cells with onsite bio gas use was above 0.80 in 2020 and below 1.2 on the PCT in 2014, indicating the technology/fuel combination will have societal value, but is currently facing market barriers which would make it a prime candidate to receive incentives.

An important program consideration had to be addressed, whether to allow a specific technology that is not cost effective to dominate the budget for incentives. In 2016, California altered the program to allocate more funds to other technologies besides electric only fuel cells. Before 2016, the budget was allocated into two different categories: 75% for renewable and 25% for emerging technologies and non-renewable fueled conventional CHP projects. Fuel cells were originally considered an emerging technology, along with biogas and advanced energy storage. Now, the program allocates 75% for energy storage, and 25% for generation. Fuel cells are now considered under the lesser allocation. This shift will have a substantial effect on the amount of fuel cell projects that get funded moving forward. This issue is not reflected in New York, another successful set of CHP programs because NYSERDA offers separate funding for CHP projects and fuel cell projects. Each having different requirements and incentives. This allows NYSERDA to tailor the program to each grouping of technologies.

Key Findings

- California focuses on the SCT and uses a reduced discount rate to capture long term benefits, but leaves out the RIM test due to the complicated representation of how DG affects rates
- California incorporates non-energy benefits like emission reductions and reliability improvements through avoided cost modeling
- Advancing technologies that may have future reduction in costs are captured through learning curves that produce "progress ratios" to be used in cost effectiveness calculations

- The study has identified the 500 kW CHP fuel cell fueled by onsite biogas as a technology that could benefit from additional focus and incentives in the program

COMMON PRACTICES DISCUSSION

PROGRAM ATTRIBUTES

This section will highlight common practices for program components from reviewed CHP programs across the country.

In reviewing programs offered across the country, many have a wide range of technologies and fuels eligible for incentives. This provides customers with various options of onsite distributed generation depending on the size and needs of the customers electrical and thermal load. It has become clear that the goals and objectives of the program direct what the program will incentivize. The Maryland Energy Administration FY17 CHP Grant was a grant solicitation aimed at promoting CHP systems, therefore systems were required to have heat recovery. For the California SGIP and NYSERDA programs, the focus is customer onsite electrical generation, rendering systems without heat recovery eligible.

In order to maximize the energy saved per dollar invested and minimize administration resources, many programs set a singular high minimum efficiency level to ensure that the projects incentivized meeting a high standard of efficient electrical generation. Minimum efficiency levels are key requirement to set the direction of the program – these requirements provide a distinct cut off for eligible projects, provide a comparison point between projects, and are an indication of potential efficient generation. When the efficiency requirement is 60% and above that often makes electric-only fuel cells ineligible for the program.

Once a technology is deemed eligible by type and efficiency level, the project has to be evaluated in some manner to receive an incentive. There are different ways in which programs across the country accomplish this. Some use a simple payback requirement ranging from up to 3 to 7 years. Other program administrators also perform a cost benefit analysis (CBA) on each project, requiring the project to have a TRC ratio greater than 1.0. Conducting a CBA on each individual project application seems to be the industry standard. Once a project is approved, the incentives are to be paid out through various types of structures.

Incentives structures and levels varied drastically between reviewed programs. As discussed previously, there are several different ways to incentivize units, from capacity payments, to design incentives, to performance incentives. No incentive structure has been identified as the best for developing CHP programs, however, there are pros and cons to each type. The optimal incentive structure depends on the resources available for the program, i.e. budget and program staff. Some incentive types require more budget dollars and staffing to review, administer, educate and incentivize, but also may provide more security for performance and/or attract and install more projects due to supportive tier incentives for each project stage. Examples of these types of incentive structures include the California SGIP or Baltimore Gas & Electric's CHP Program. Other incentive structures are more low maintenance by not requiring complicated incentive calculations and long term tracking for performance payments.

Cost Benefit Evaluations Review

Part of this study included a review of technical studies focused on cost benefit analyses. The goal was to understand how other states and programs are evaluating the cost effectiveness of distributed generation at a high level.

In New York, the state was looking to reassess how resources are evaluated as a part of the REV proceedings. Synapse Energy took a deeper dive into what DER costs and benefits are used in each of the tests and provided recommendations for a path forward to develop a CBA framework. In California, a cost benefit analysis was performed for the SGIP. The methodology and results from the CBA were used to inform this study.

It is clear from both studies that there is a shift from using the TRC to using the SCT to evaluate the cost effectiveness of distributed generation. DG has benefits that go beyond just the utility participants and non-participants, but society as a whole. Both studies also discuss the use of a societal discount rate to better account for the longer life benefits. Additionally, both studies discuss the use of traditionally "hard-to-quantify" benefits or non-energy benefits, these might include reliability increases, strengthened customer empowerment, reduced emissions, etc. The inclusion of these benefits would also be more representative of the actual DG benefits.

Key Findings

Below are a list of the key findings from the literature review and comparative analysis section. The overarching theme of this section is that there is no one size fits of for designing a program that promotes the installation of CHP and fuel cell technologies, but there are several items to consider when doing so.

- **Each program reviewed had a clear program objective – generation, emission reduction, market transformation etc.- that was reflected in how the program was designed.**
    - In Maryland – for both the state program and utility programs – the objective is to incentivize the most cost effective projects. This objective is reflected in the fact that the programs do not incentivize electric-only fuel cells because the technology is generally deemed not cost effective. The program requires waste heat recovery and sets a high minimum efficiency level that typically rules out electric only fuel cells.
- **There are many ways to design incentives for promoting CHP and fuel cells, indicating there is no best practice for designing the structure.** Each incentive structure has pros and cons, and should be chosen based on the program objectives and the resources available to the program (i.e. budget, staff etc.).
    - Incentives range in structure type and complexity. As the complexity of the incentive structure increases, so does the need for more program staff resources to provide to administer. Some programs have simple one time capacity rebates for all technologies with no additional bonuses, such as the Maryland Energy Administration's grant program offering \$425-\$575/kW (depending on system size). This simple structure differs from other programs with complicated tiered incentive structures that decline with size, offering a combination of capacity and performance based incentives (i.e California's SGIP).

- **Several states require the submission of annual performance data to provide performance based incentives.** Programs in states, like New York, California and Maryland, use the performance data to provide incentives, as well as, track and monitor project progress. New York (NYSERDA) goes as far as to track and monitor projects on a real time basis. Real time operational data is gathered and monitored through NYSERDA's DG Integrated Data System[156]
- **Successful programs[157], like programs run by NYSERDA and the California PUC, have technology neutral incentives, but diversify incentives when needing to tailor to specific technology needs or goals of the state.**
    - For example, NYSERDA has one program for conventional CHP (reciprocating engines, gas turbines etc.) with technology neutral incentives. There is a separate set of program directed at fuel cells (large and small programs). NYSERDA has chosen to promote fuel cells separately, giving the technology more focused opportunity. In California, conventional CHP and fuel cells are provided the same incentive, however projects that utilize renewables (wind or biogas) receive a higher incentive. In both states, the program goals are centered around reduced emissions and generation.
- **Other than New Jersey, no other state or utility program has offered distinct incentives for both fuel cells with and without heat recovery.** Of the twenty-two programs reviewed, there are only six programs where fuel cells without heat recovery are eligible technologies. For the other sixteen programs reviewed, a waste heat recovery requirement, minimum efficiency requirement, and or cost effectiveness screening may rule fuel cells without heat recovery ineligible.
    - The NYSERDA fuel cell programs have a minimum efficiency requirement of 50%, stating in the program documents that the focus of the program is electrical generation benefits and therefore the recovery of waste heat is not required but recommended due to the benefits. The programs (small FC and Large FC) do not offer differing incentives for FC projects with or without heat recovery.
    - California SGIP allows electric only fuel cells, and only requires a minimum efficiency of 40%, but projects must meet other strict requirements such as greenhouse gas emission standards. Similarly to New York, the program does not offer different incentives for FC with or without heat recovery
- **Most programs institute one singular minimum efficiency requirement that ranges from 60% to 65% to streamline the application and incentive process.**
    - However – it is important to note that, programs in New York, California and Pennsylvania do not follow this. New York (50% for fuel cells, 60% for CHP) has different requirements for separate programs and California (40% for all technologies) has a lower efficiency requirements – each due to the program objective. Also the PECO CHP program sets different efficiency levels based on the CHP technology in order to better tailor the requirements to typical individual CHP efficiencies.

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[156] http://chp.nyserda.ny.gov/home/index.cfm

[157] As defined by number of installed projects and long history of program development. The NYSERDA and California SGIP have installed over 100 CHP and fuel cell projects over a long program history.

- **Most programs, except New Jersey, Ohio, and Maine express the minimum efficiency requirement as HHV, Higher Heating Value, as opposed to LHV or Lower heating Value.** HHV is a more inclusive efficiency rating because it accounts for all available thermal heat, whereas LHV excludes heat from water vapor. HHV is more appropriate for CHP applications because of the inclusive nature of the efficiency calculations.
- **Almost all programs have some sort of formal screening process for individual projects** – TRC cost effectiveness test, payback threshold or weighted criteria groupings. More states opt for the TRC coste effectiveness screening with the threshold set at 1.0, some in conjunction with payback requirements.
  - States like Maryland, Illinois, and Rhode Island required a TRC ratio of 1.0 or higher. The program in Ohio, Illinois, and Massachusetts have payback requirements. California has a GHG threshold that projects must meet to receive incentives, this is directed to meet the program goal of emission reductions.
- **In reviewing the technical studies on cost benefit analysis, both studies emphasized the use of the SCT to evaluate the cost effectiveness of distributed generation**. California applies the test on both the individual project level, and a program level – as it reviews the technologies for their cost effectives relative to the program in the impact evaluation reviewed for this study. In the study conducted by Synapse for New York, Synapse Energy recommends the use of the SCT across the board when evaluating any DER. It is assumed that this would translate to the project and program levels.
  - Both studies also discussed the use of a societal discount rate to better account for the longer life benefits and encourage the use of traditionally “hard-to-quantify” benefits or non-energy benefits. These might include reliability increases, strengthened customer empowerment, reduced emissions, etc.

3

PRIMARY FUEL CELL ECONOMIC ANALYSIS

INTRODUCTION

The literature review section provides a foundation for understanding how other programs across the country incentivize and evaluate CHP and FC technologies. As part of Phase 1 of this effort, the Center for Energy, Economic and Environmental Policy (CEEEP) conducted a preliminary Cost-Benefit analysis (CBA) based upon the fuel cell (FC) projects that do not have heat recovery. Using the Ben-Cost model developed by the TRC Solutions (TRC), the five standard energy efficiency CBA metrics are presented including both the Total Resource Cost Test (TRC) and Societal Cost Test (SCT) discussed above. The use of all five standard CBA metrics show how a single project may be evaluated and how those results may vary. CEEEP has also compiled a database of approved New Jersey fuel cell and CHP projects to compare their proposed installed costs versus their engineering efficiencies along with other financial and performance metrics such as payback, cost per kilowatt, capacity factors, etc. The goal is to further understand the economics fuel cell technologies in New Jersey. This knowledge will help to inform how best to address fuel cells in the NJ CHP & FC program.

The results presented here should be considered preliminary for several reasons. First, installation and operational data for the recent set of fuel cell applications are not available. Actual costs and performance may differ from what are anticipated and can have a substantial impact on the economics of these resources. Second, Phase 2 of this project involves a more sophisticated and detailed modeling effort that should provide additional insights into the economics of fuel cells and other distributed energy resources.[158] Third, there are federal tax incentives, the Investment Tax Credit (ITC) and the Modified Accelerated Cost Recovery System (MACRS), and possibly New Jersey State property tax issues that affect the economic analyses. An analysis of these issues was beyond the scope of this report given the short-period of time for the Phase I analysis. Additional analysis that includes the ITC was conducted afterwards, and will be included in future report iterations.

Any CBA requires numerous assumptions, many of which are subject to a substantial range of uncertainty. This work relies on crucial avoided cost assumptions regarding natural gas, electric, and emissions factors. These avoided cost assumptions are provided in an appendix to this report. They are the same assumptions that AEG is using to plan energy efficiency programs for New Jersey.

The project-level data was drawn from the fourteen FC without heat recovery applications that were completed to the NJCEP and C&I Market Manager from January 1, 2012 to June 20, 2016[159] In 2015 a previous evaluation conducted by Cadmus reviewed eight fuel cell projects installed as a part of the NJ CHP & FC[160]. The FC projects in the current evaluation serve a mixture of

[158] Additionally, it is not unusual for the characteristics of a proposed project such as size, cost, or operational parameters to change after an application is submitted during project development prior to commissioning. The current incentive program is designed to capture the updated project information during the post- installation program inspection an record these changes in the program database to facilitate an accurate evaluation of project performance.
[159] Not included is the fuel cell applications processed by the NJ EDA
[160] This evaluation is described in the Introduction section of the Literature Review.

commercial offices, big box retailers, and industrial facilities. The specific projects names or other identifying details are not provided in order to protect possible commercially sensitive data.

DESCRIPTION OF COST BENEFIT ANALYSIS

CBA is a commonly used set of tools to analyze the economics of projects including their energy efficiency. Before reviewing the CBA in the context of energy efficiency, it is worth distinguishing it from the concept of cost effectiveness. Although sometimes the terms cost effectiveness and CBA are used interchangeably, they have distinct meanings. Both methods monetize project costs. The difference is that cost effectiveness does not monetize the project's benefit and instead reports the cost per unit of benefit.

For example, a cost effectiveness analyses may calculate the cost per kilowatt-hour (kWh) saved from an energy efficiency program. Energy efficiency Project A may cost $0.10 per kWh saved whereas Project B may cost $0.20 per kWh saved. Clearly the first project is more cost effective than the second. In contrast, CBA monetizes both the costs along with all of the benefits. If Project A has multiple benefits (electricity saved, emissions avoided, etc.) each of these benefits is assigned a monetary variable. The net present value of the costs is compared to the net present value of the benefits. Net present value means that the time value of money is accounted for using the discount or "interest rate." If the dollar value of the benefits exceeds the costs, then the project is considered economical. A cost effectiveness analysis must handle each of these benefits separately making it difficult to compare projects that have multiple benefits.

A CBA is not a technical standard. It does not require the project that is being evaluated to satisfy specific technical requirements. This makes CBA a useful tool when comparing various technology-based energy efficiency options and distributed energy resources. Of course, a CBA accounts for the technical characteristics and performance of a project in its calculations.

As with any tool, the CBA has its limitations. As noted above, its results depend heavily on its assumptions. For one, project costs are typically easier to quantify than benefits. This is not to say the projections of project costs do not contain uncertainty. It is, however, generally the case that it is easier to quantify the cost of capital investments, operations, and maintenance than to quantify economic benefits such as future energy savings or benefits of reduced emissions. Second, as discussed earlier in this report, there is an ongoing public policy debate regarding how to conduct the CBAs of DERs. One's view of which assumptions and methodologies should be used obviously can influence the results of any CBA.

Descriptions of Cost Benefit Analysis

The description below provides an overview of the standard cost CBA metrics. The two metrics that cover the broad range of costs and benefits and therefore are useful indicators of the economic efficiency of the technology or project under evaluation are the following:

- **Total Resource Cost Test (TRC):** is one of the primary method of assessing the overall costs and benefits of energy efficiency measures and programs. TRC measures the net costs and benefits of an energy efficiency program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test represents the combination of the effects of a program on both participating and non-participating customers.

- **Societal Cost Test (SCT):** is broader than the TRC and is intended to determine the effects of a program on society as a whole not just the utility, participants, and non-participants. The benefits are the avoided supply costs of energy and demand as well as externalities (including environmental benefits, etc.). The costs include the program costs incurred by the utility and the participants.

Three other CBA metrics that are used help quantify the costs and benefits to particular segments of stakeholders. They are the following:

- **Participant Cost Test (PCT):** quantifies the benefits and costs to the customer due to participation in a program. The benefits include reduction in the participant's bill and incentives received. The costs are out-of-pocket expenses incurred as a result of participation. A PCT CBA metric greater than one indicates (i.e., the benefits exceed the costs) that the customer should be willing to participate in the program because the benefits.
- **Ratepayer Impact Measure Cost Test (RIM):** measures what happens to a customer's bill or rates due to changes in utility revenues and operating costs. Benefits are the savings from avoided supply costs of energy and demand. Costs are the program costs incurred by the utility, participant incentives, and decreased utility revenues. Programs that have a RIM CBA metric greater than one indicate that non-participating ratepayers benefit from the program.
- **Program Administrator (PACT) or Utility Cost Test (UCT):** measures the net costs of a program as a resource option based on the costs incurred by the program administrator, excluding any net costs incurred by the participant. The benefits are the avoided supply costs of energy and demand. The costs are the program costs incurred by the program administrator/utility and participant incentives.

BEN-COST MODEL DESCRIPTION

Ben-Cost is a Microsoft Excel®-based model that integrates technology-specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system. The model allows for efficient integration of large quantities of measure, building, and economic data to optimize DSM[161] portfolios. Ben-Cost is currently being utilized in dozens of other states and utilities for DSM planning.

Ben-Cost provides all of the standard cost-effectiveness test results, including Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure Test, and Societal Test. Ben-Cost includes general and measure-specific inputs, detailed in below:

Table 3-1 BenCost Model Inputs

General Inputs	Specific-Project Inputs
Retail Rate ($/kWh, $/therm, $/gallon)	Utility Project Costs ($)
Non-Electric Fuel Retail Rate ($/Fuel Unit)	Administrative Costs ($)
Commodity Cost ($/kWh, $/therm, $/gallon)	Incentive Costs ($)
Demand Cost ($/kW/Yr)	Total Utility Project Costs ($)

[161] Demand Side Management

Peak Reduction Factor (%)	Direct Participant Project Costs ($/Participant)
Variable O&M ($/kWh and $/therm)	Participant Non-Energy Costs (Annual $/Part)
Non-Electric Fuel Cost ($/Fuel Unit)	Participant Non-Energy Savings (Annual $/Part)
Non-Electric Fuel Loss Factor	Project Life (Years)
Electric Environmental Damage Factor ($/kWh, $/therm)	Avg. kWh/Participant Saved
Participant Discount Rate (%)	Avg. therm/Participant Saved
Utility Discount Rate (%)	Avg. Non-Electric Fuel Units/Part. Saved
Societal Discount Rate (%)	Avg. Additional Non-Electric Fuel Units/Part. Saved
Loss Factor (Energy, Capacity, Gas, Water)	Number of Participants
Project Analysis Year	Total Annual kWh, therm, and gallon Saved
Growth and Escalation Factors (%)	Incentive/Participant

Ben-Cost also produces a series of general outputs and specific outputs for each benefit cost test as seen in Table 3-2.

Table 3-2 BenCost Model Outputs

General Outputs	Benefit-Cost Test Outputs (Per Test)
Annual Utility Peak Demand Reduction	Net Present Value of Benefits – Costs
Annual Utility Energy Reduction	Benefit-Cost Ratio
Lifetime Utility Demand Reduction	Total Benefits
Lifetime Utility Energy Reduction	Total Costs
Levelized Costs per kWh, therm, and kW	
First Year Cost per Energy Saved	
Lifetime Cost per Energy Saved	
Annual Participant Savings	

Ben-Cost was the primary tool used to perform the benefit-cost analysis in support of the CHP FC Evaluation Study. As currently configured, Ben-Cost does not consider tax incentives such at the ITC, MACRS or property tax issues.

Description of Data Set Utilized in Cost Benefit Analysis

This study examined a comprehensive data set which included project details of all NJCEP Small Scale CHP & FC program applications submitted during Program Fiscal Years 2013 through 2016. The calendar year date range which aligns with this time period is January 1, 2012 through June, 30, 2016.

Ninety-four projects were submitted to the program for approval during this period. Forty-three CHP and FC projects reached the Commitment stage, where incentive monies are approved and reserved specifically for those projects. Reasons vary for why projects did not achieve program commitment, some include: funding complications, technology glitches, site challenges, or construction issues. During this time period, fifteen (34.9%) applications proposed to utilize FC technology, fourteen of which have been identified as completed applications and reviewed in this analysis. The remaining twenty-eight applications utilize conventional CHP technology and will be analyzed in Phase II. To date, no FC projects in the Small Scale CHP FC Program have reached a stage requiring submittal of twelve-month operational data [162]. Of the projects in this dataset, operational data was submitted for seven CHP projects.

Table 3-3 NJCEP Small Scale CHP & FC Program Dataset Description

Applications between January 1, 2012 through June, 30, 2016

Number of Applications	Status/Description
94	Submitted
43	Committed/Approved for Incentive
15	FC Total Applications (only utilized w/o heat recovery)
14	FC Completed Applications (only utilized w/o heat recovery) →Reviewed for this analysis
0	FC Projects (only utilized w/o heat recovery) w/ operation data
28	Conventional CHP projects
7	CHP projects w/ operational data

Note: This is a subset of the total applications submitted to the NJ CHP & FC project. The fifteenth application that did not complete the process had costs and performance characteristics that were in line with those of the complete application.

The data points captured were consistent across individual projects, spanning a wide spectrum of detail; from applicant, contractor, and design team information to site photos, construction drawings, air emissions, and financial analysis. Specific project information included, but not limited to; prior twelve months of gas and electric utility billing, proposed system operating hours and load profile, projection of utilized thermal output, and interrelationship with existing or new heating and/or cooling equipment. Also included were narratives detailing the mode of operation, operational sequence, metering plan, and system interconnection with the grid where applicable. Projected itemized costs broken down by equipment type, design and construction labor, and ten-year maintenance expenses as well as funding source estimates were included.

Dataset Exclusions

While the dataset included detailed project information described above, the dataset did not include installation or operational data for fuel cells. The importance of collecting installation and operational/performance data (i.e., output, capacity factors, major capital expenses, actual project operating lifetime) over time is critical, particularly for emerging technologies, for the accuracy of economic analyses. In particular, three key pieces of data that the economic analysis relies upon are projects' installation costs, capacity factors (i.e., actual output divided by total possible output) and the operational lifetime of the facility. Several other states, like New York, California and Maryland, require the submission of annual performance/operational

[162] One 2 MW fuel cell project that utilizes heat recovery, in the Large CHP FC project managed by EDA, has submitted operational data. This project was out of the scope for this evaluation report.

data to provide the performance based incentives. In New York, this data is tracked in real time and provided publically. However, gathering and tracking real time data requires significant resources to maintain such a database. Having operational data over a sufficient amount of time will enable the comparison of projections and assumptions made in applications to actual performance, which will help inform the Office of Clean Energy on future program changes and design.

Non-New Jersey Fuel Cell and CHP Studies

In March 2016, the Department of Energy's Office of Energy Efficiency and Renewable Energy released its CHP Technical Potential Study[163] The report considers CHP to be a crucial way to increase US competitiveness by reducing operating costs and greenhouse gas emissions while improving energy security, resiliency, infrastructure and efficiency. The authors' analysis shows 141GW of traditional topping cycle CHP (as opposed to waste-heat-to-power) potential for on-site use in the industrial (65GW) and commercial (76GW) sectors. These sectors show relatively more promise for the spread of CHP because their applications are typically more electricity intensive than in other sectors.

In 2013, Pacific Northwest National Laboratory prepared a report for the DOE which consisted of a comparison of CHP systems, including fuel cells[164]. They conducted a simple payback analysis for a comparable gas engine, microturbine and micro fuel cell system, holding fuel costs per MMBtu and electricity prices equal. The results showed the gas engine paid back in 2.92 years, the microturbine in 3.99 years, and the micro fuel cell at 9.77 years.

Aside from less specific national explorations of distributed energy systems, there have been several recent inquiries into the economic profile of fuel cells at the state level. In 2011, the National Fuel Cell Research Center (NFCRC) conducted cost-benefit analysis which found that the societal benefits of stationary, baseload generating fuel cells exceeded the societal costs in four operating scenarios (running on natural gas or renewable fuel, and with or without cogeneration), both with and without the California Public Utilities Commission's incentive payments.[165]

ANALYSIS OF NEW JERSEY FUEL CELL APPLICATIONS

Table 3-4 summarizes the database of fuel cell and CHP proposals made to the New Jersey Board of Public Utilities. The fuel cell project annual system efficiency and cost data was drawn from the fourteen FC without heat recovery completed applications submitted to the NJOCE within the last two years. Note that none of the FC systems are blackstart and islanding capable, meaning that these FC cannot operate when the electric grid is not functioning. The CHP data is drawn from project applications submitted to the Clean Energy Program within the past two years. Only the twenty-one unique CHP applications from 2015 and 2016 are included in the data table; if a project appeared in 2015 and 2016, only the more recent filing was used. Heat Recovery Generator projects (only three since 2014) were excluded because their annual system efficiencies are often over 100%, well beyond the typical ranges seen in CHP and FC projects.

[163] http://energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
[164] Brooks, K., et al. "Business case for a micro-combined heat and power fuel-cell system in commercial applications." Pacific Northwest National Laboratory (2013).
[165] http://www.nfcrc.uci.edu/3/FUEL_CELL_INFORMATION/MonetaryValueOfFuelCells/Fuel_Cell_Value-Methodology_2011_FINAL_072411_Large-Units_Final.pdf

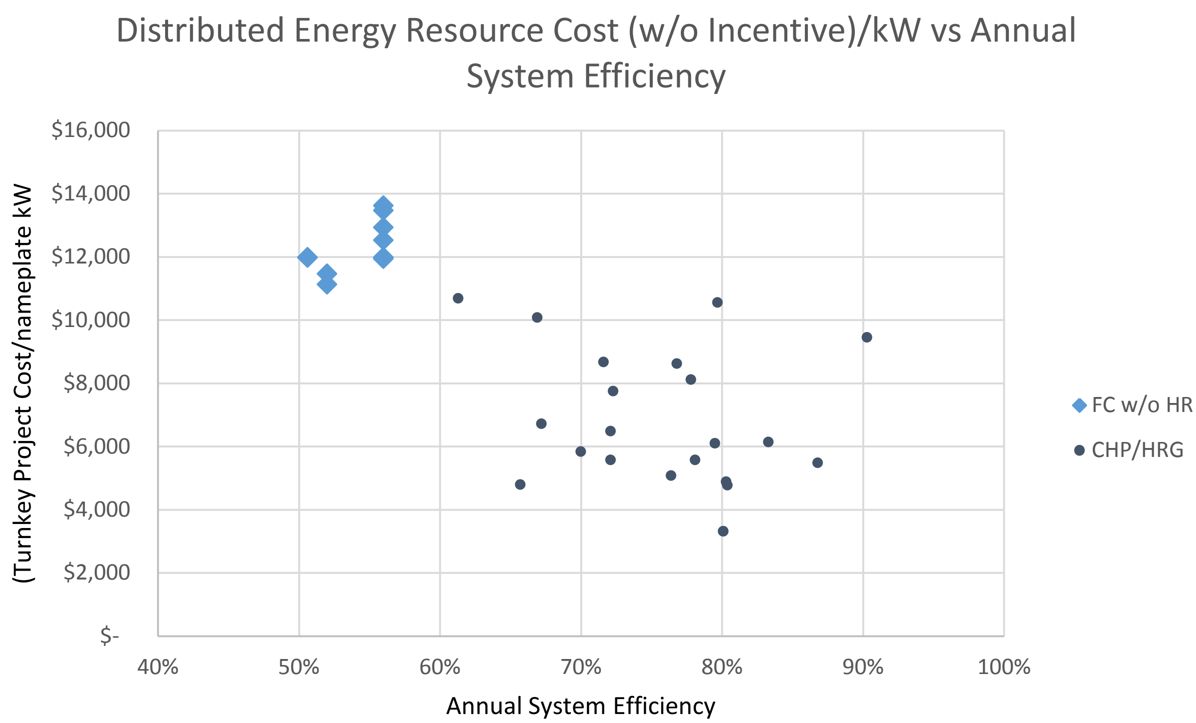
Table 3-4 Fuel Cell (2014-2016) and CHP (2015-2016) Project Efficiencies and Costs

Equipment Type	Proposed Annual System Efficiency	Turnkey Project Cost	Final NJCEP Incentive Amount	Turnkey Project Cost - Incentive	Total Installed Rated Capacity (kW)	Cost (with NJCEP incentive) per kW
CHP	90.3%	$ 944,710	$ 225,000	$ 719,710	100	$ 7,197
CHP	76.8%	$ 861,765	$ 200,000	$ 661,765	100	$ 6,618
CHP	76.4%	$ 2,285,184	$ 900,000	$ 1,385,184	450	$ 3,078
CHP	86.8%	$ 2,463,891	$ 900,000	$ 1,563,891	450	$ 3,475
CHP	78.1%	$ 2,504,971	$ 900,000	$ 1,604,971	450	$ 3,567
CHP	72.1%	$ 2,504,971	$ 900,000	$ 1,604,971	450	$ 3,567
CHP	72.3%	$ 581,269	$ 168,750	$ 412,519	75	$ 5,500
CHP	80.1%	$ 2,158,229	$ 600,000	$ 1,558,229	652	$ 2,390
CHP	67.2%	$ 671,852	$ 201,556	$ 470,296	100	$ 4,703
CHP	79.7%	$ 105,500	$ 20,000	$ 85,500	10	$ 8,550
CHP	72.1%	$ 647,847	$ 194,354	$ 453,493	100	$ 4,535
CHP	80.3%	$ 365,800	$ 109,740	$ 256,060	75	$ 3,414
CHP	65.7%	$ 4,786,216	$ 1,435,865	$ 3,350,351	1000	$ 3,350
CHP	79.5%	$ 457,620	$ 137,286	$ 320,334	75	$ 4,271
CHP	77.8%	$ 608,363	$ 168,750	$ 439,613	75	$ 5,862
CHP	71.6%	$ 866,619	$ 225,000	$ 641,619	100	$ 6,416
CHP	66.9%	$ 1,008,033	$ 225,000	$ 783,033	100	$ 7,830
CHP	80.1%	$ 2,158,229	$ 600,000	$ 1,558,229	652	$ 2,390
CHP	70.0%	$ 1,167,000	$ 350,100	$ 816,900	200	$ 4,085
CHP	80.4%	$ 357,750	$ 107,325	$ 250,425	75	$ 3,339
CHP	83.3%	$ 2,762,605	$ 1,012,500	$ 1,750,105	450	$ 3,889
FC w/o HR	52.0%	$ 6,876,800	$ 1,800,000	$ 5,076,800	600	$ 11,461
FC w/o HR	52.0%	$ 11,128,000	$ 2,000,000	$ 9,128,000	1000	$ 11,128
FC w/o HR	52.0%	$ 11,128,000	$ 2,000,000	$ 9,128,000	1000	$ 11,128
FC w/o HR	50.6%	$ 2,994,427	$ 750,000	$ 2,244,427	250	$ 11,978
FC w/o HR	50.6%	$ 2,395,542	$ 600,000	$ 1,795,542	200	$ 11,978
FC w/o HR	50.6%	$ 2,395,542	$ 600,000	$ 1,795,542	200	$ 11,978
FC w/o HR	56.0%	$ 3,593,314	$ 900,000	$ 2,693,314	300	$ 11,978
FC w/o HR	56.0%	$ 2,395,542	$ 600,000	$ 1,795,542	200	$ 11,978
FC w/o HR	56.0%	$ 9,699,761	$ 2,000,000	$ 7,699,761	750	$ 12,933
FC w/o HR	56.0%	$ 2,395,542	$ 600,000	$ 1,795,542	200	$ 11,978
FC w/o HR	56.0%	$ 8,356,040	$ 1,972,775	$ 6,383,265	700	$ 11,937
FC w/o HR	56.0%	$ 9,397,287	$ 2,000,000	$ 7,397,287	750	$ 12,530
FC w/o HR	56.0%	$ 10,897,238	$ 2,000,000	$ 8,897,238	800	$ 13,622
FC w/o HR	56.0%	$ 13,471,547	$ 2,000,000	$ 11,471,547	1000	$ 13,472

Note: Fuel cell turnkey project cost includes ten years of annual maintenance cost.

Two key characteristics of both FC and CHP are their proposed capital costs and their estimated efficiencies, which are plotted in Figure 3-1 based upon the data in Table 3-4.

Figure 3-1 Fuel Cell and CHP Capital Cost/kW vs Proposed System Efficiency



Projects that have the low capital costs and high efficiencies, which are located in the lower right-hand side of Figure 3-1, are preferable to those that have higher capital costs and lower efficiencies. As Figure 3-1 indicates, the FC projects proposed to the BPU are clumped together (and in some cases, overlapping) in the upper left-hand side, indicating that they are higher cost and less efficient than the CHP projects. Both Fuel Cell and CHP projects vary greatly in size depending on the application (e.g. 100kW for a middle school vs. 1000kW for a large manufacturing facility), but the data shows CHP systems operate at higher system efficiencies with the potential to deliver power at a lower total cost per kilowatt as compared to fuel cell projects.

Currently FC receive a 30% ITC and CHP receive a 10% ITC as well as any MACRS. Accounting for these tax incentives would affect the presentation in Figure 3-1. Such an analysis was beyond the scope of Phase 1 given its timing. Qualitatively, these adjustments would both move FCs and CHP down in the above graph, although the FCs would move more relative to the CHP. The ITC is set to expire on December 31, 2016, however it could be extended.

While the current analysis does not include the federal tax incentives, such as the Investment Tax Credit because of timing, additional analysis that incorporates the ITC was completed and will be included in future report iterations. More analysis is needed to properly consider Modified Accelerated Cost Reduction System (MACRS), and any applicable property tax benefits.

Table 3-5 reports the CBA results using the Ben-Cost model for FCs. Metrics below 1 indicate that the costs, on a net present value basis, are larger than the benefits, on a net present value basis. Metrics above 1 indicate that the benefits exceed the costs. As noted above, the Ben-Cost model as currently configured does not account for Federal and State tax incentives and therefore these are not included in Figure 3-5. **Note that tax incentives do not affect the SCT results. The reason is that tax incentives are paid for by society, although the tax benefit is**

received by the participant. Thus, the transfer payment from taxpayers to the participant does not reduce society's overall costs.

Table 3-5 Results for the Five CBA Tests for Fuel Cell Applications

Project	TRC	Societal	Participant	RIM	Program Admin.
A	0.27	0.82	0.90	0.30	1.02
B	0.24	0.72	0.72	0.33	1.33
C	0.24	0.72	0.72	0.33	1.33
D	0.21	0.66	0.73	0.30	0.86
E	0.24	0.69	0.73	0.34	0.97
F	0.21	0.66	0.73	0.30	0.86
G	0.25	0.72	0.83	0.30	0.99
H	0.21	0.66	0.73	0.30	0.86
I	0.17	0.50	0.60	0.29	0.84
J	0.21	0.66	0.73	0.30	0.86
K	0.24	0.69	0.79	0.31	1.03
L	0.23	0.66	0.74	0.31	1.09
M	0.21	0.60	0.67	0.32	1.16
N	0.21	0.61	0.64	0.34	1.45

For the two metrics that cover the broadest range of costs and benefits and therefore are useful indicators of the economic efficiency FC, the CBA metrics are less than 1 indicating that the costs exceed the benefits for the 14 applications evaluated. The Societal CBA metrics are closer to one than the TRC because it accounts for the environmental benefits due to FC compared to centralized power plants. The only CBA metric that for seven projects exceeds 1 is the PACT. As noted previously, the PACT only considers the costs and benefits to the program administrator and not the implications for ratepayers and society in general.

Figure 3-2 illustrates the relationship between the project turnkey cost per kW of manufacturer-specified system size (including the cost of incentives) and the total installed rated capacity (in kW) of the FC projects in Table 3-3. Although there may appear to be a slightly downward trend in cost as system capacity increases, the lack of a clear downward trend from left to right (which would indicate that larger projects are less costly per kW than smaller projects) reinforces the need to collect more data. Collecting more project-level data will provide useful baseline information for future cost-benefit and other types of analyses. This is especially true for data collection efforts *after* DG resources have been installed, since project performance and cost information is particularly limited for recent projects.

Figure 3-2 Fuel Cell without Heat Recovery Installed Capacity vs Total Cost/kW

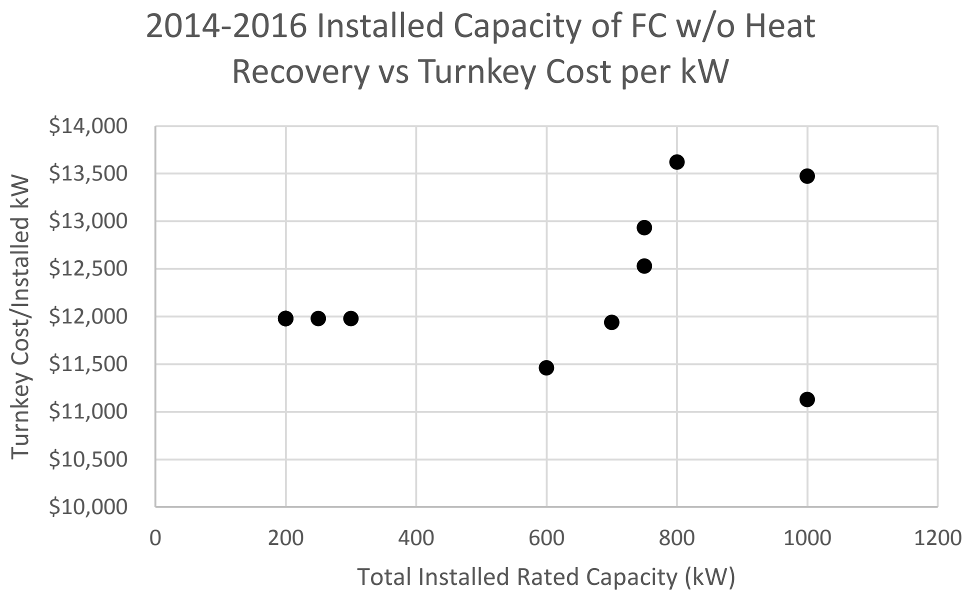


Table 3-6 presents several identifying features of the aforementioned fuel cell without heat recovery projects in addition to their fuel conversion efficiency, energy input in MMBtu, electric output in kWh and approximate capacity factors. Note that for all cases, the fuel conversion efficiency was equal to the proposed system efficiency. In addition, note that the capacity factors are 95% or 100%. A 100% capacity factor indicates that the FC runs at full output all the time. Capacity factors have a direct bearing on how the CBA metrics and cost-effectiveness of FC, and operational data would be useful to determine if these anticipated capacity factors materialize.

Table 3-6 Fuel Cell without Heat Recovery System and Financial Metrics

FC Project Number	Building Type	Fuel Conversion Efficiency (%)	Total Installed Rated Capacity (kW)	Total Project Cost ($)	Final NJCEP Incentive Amount ($)	Annual Energy Input (MMBtu)	Annual Fuel Cell System Electric Output (kWh)	Approximate Capacity Factor
A	X-Other	52	600	6,876,800	1,800,000	32,763	4,993,200	95%
B	X-Industrial	52	1,000	11,128,000	2,000,000	54,605	8,322,000	95%
C	X-Office	52	1,000	11,128,000	2,000,000	54,605	8,322,000	95%
D	Commercial - Retail	50.6	250	2,994,427	750,000	14,031	2,080,500	95%
E	Commercial - Retail	50.6	200	2,395,542	600,000	11,226	1,663,424	95%
F	Commercial - Retail	50.6	200	2,395,542	600,000	11,226	1,663,424	95%
G	Commercial - Retail	56	300	3,593,314	900,000	16,012	2,629,027	100%
H	Commercial - Retail	56	200	2,395,542	600,000	10,648	1,752,000	100%
I	Commercial - Office	56	750	9,699,761	2,000,000	40,030	6,570,000	100%
J	Commercial - Retail	56	200	2,395,542	600,000	10,141	1,664,400	95%
K	Commercial - Office	56	700	8,356,040	1,972,775	35,493	5,825,400	95%
L	Industrial	56	750	9,397,287	2,000,000	38,029	6,241,500	95%
M	Commercial - Retail	56	800	10,897,238	2,000,000	40,564	6,657,600	95%
N	Commercial - Retail	56	1,000	13,471,547	2,000,000	50,705	8,322,000	95%

Table 3-7 contains the estimated FC without heat recovery equipment lives as reported in each project application as well as the results of a simple payback period analysis based upon the application considering the effects of including or excluding NJCEP incentives.[166] In many of the recent FC proposals, the simple payback without incentives exceeds the expected life of the equipment. Simple payback periods with NJCEP incentives, but not federal or possible state tax incentives, factored in are typically three to five years shorter than if no incentive was applied.

The annual system fuel input ($) is larger than annual avoided electric purchase ($) for project A. This accounts for negative payback period indicating that the project will never pay for itself. Note that simple payback periods do not account for the time value of money, meaning that they overestimate the economic benefits relative to the costs of the project. Table 3-7 also includes the internal rate of return (IRR) for each FC project. A negative or low IRR indicates that the project has no or low financial viability.

Furthermore, past analysis of FC in New Jersey for the period 2003-2010 indicate operational performance below expectations, higher than anticipated operations and maintenance costs, and the need to undertake major component replacements (i.e., the FC stacks) that cost up to

[166] CEEEP does not have access to any other data regarding these FC applicants such as power purchase agreements (PPAs).

two-thirds of the cost of the fuel cell after six to eight years.[167] Advances in FC technology, maintenance, and operations are likely to have improve compared to past performance, which is why it is critical to have a long time series of FC cost and performance data in order to properly evaluate their economics.

Table 3-7 Fuel Cell without Heat Recovery Equipment Life and Simple Payback Period

FC w/o HR Letter ID	Estimated Equipment Life (years)	Simple Payback Period w/o Incentive (Years)	Simple Payback Period w/ Incentive (Years)	IRR (at 7%) w/o Incentive
A	20	-37	-28	
B	15	25	20	-0.068
C	15	33	27	-0.11
D	15	20	15	-0.04
E	15	31	23	-0.09
F	15	21	16	-0.05
G	15	16	12	-0.01
H	15	19	14	-0.03
I	10	21	17	-0.22
J	15	19	16	-0.03
K	15	12	10	0.03
L	15	18	14	-0.03
M	15	21	17	-0.05
N	15	20	17	-0.04

Note: An IRR was not available on Project A's application.

The method by which DG are evaluated depends on the objectives of the New Jersey Clean Energy Program. If the sole or primary objective of the program is obtaining high engineering efficiency or economic efficiency, then the preliminary analysis of the comparison of capital costs to engineering efficiency, the CBA metrics, and the simple payback periods suggest that FC without heat recovery are not cost effective or economically efficient based upon the proposals reviewed. This preliminary finding is subject to change based upon the receipt of installation and operational data, the analysis of tax incentives, and the additional analysis that is proposed for Phase 2 of this project.

DG may have broader New Jersey-wide impact on its economy such as employment and ability to leverage New Jersey dollars. Such a macroeconomic analysis, however, is not appropriate on a per applicant basis as it would be administratively burdensome, although at a program or portfolio level it may be informative.

[167] Impact Evaluation of Small-Scale Wind, Biopower, and Fuel Cell Programs for the New Jersey Office of Clean Energy, Cadmus, March 20, 2015, pp. 40-42.

KEY FINDINGS

The above analysis finds that:

- Long life actual installation and operational data and costs are essential to properly determining the cost effectiveness of a project.
- The evaluation method used will vary depending on the program objectives.
- The TRC and SCT metrics, which are the primary CBAs used to evaluate DG, fail to show a net economic benefit for FC without heat recovery. The Program Administrator metric is the only one that yields a positive cost-benefit for some FC without heat recovery.
- Budget limitations may prevent the funding of all projects whose SCT or TRC exceed one; thus it is important to not only compare CBA metrics to one but also to other project across technologies.
- Based upon the applications reviewed, FC without heat recovery are not currently cost-effective when compared to other DG or economically efficient based upon the TRC and SCT metrics, simple payback periods and IRR.
    - If the primary objective is to incentivize the most cost effective and or efficient systems, then the analysis suggests that fuel cells without heat recovery are not cost effective.
    - Note that simple payback analysis does not account for the time value of money and therefore overestimates the economic value of capital-intensive assets such as FCs and CHP. The simple payback calculation used in the current analysis also does not include the federal tax incentives. Additional analysis was conducted that incorporates the ITC and will be included in future report iterations.
- When compared to CHP applications, based upon the applications reviewed, FC without heat recovery applications have higher capital costs and lower efficiencies than CHP.
    - Both Fuel Cell and CHP projects vary greatly in size depending on the application (e.g. 100kW for a middle school vs. 1000kW for a large manufacturing facility), but the data shows CHP systems operate at higher system efficiencies with the potential to deliver power at a lower total cost per kilowatt as compared to fuel cell projects.
- Future FC may provide resiliency benefits (as well as additional costs associated with being blackstart and islanding capable). In order to capture those benefits, the appropriate economic and financial metrics would have to be developed as part of Phase 2.
- Broader macroeconomic analyses can be conducted to evaluate the contribution of DER on the New Jersey economy, such as employment, New Jersey dollars leveraged etc. This type of analysis is not appropriate at the level of individual applications but may be useful the program or portfolio level.
- These findings are preliminary and subject to change upon the receipt of installation and operational data, consideration of federal and state tax incentives, and the additional analysis that is proposed for Phase 2 of this project including the consideration of locational benefits and costs.

4

DATA AND TECHNOLOGY DRIVEN METHODOLOGY

Evaluation of CHP & FC technologies using simple payback and cost benefit analysis may not capture the full benefits of CHP & FC in terms of the broader system benefits to the grid. Some applications may deliver broader system benefits such as resiliency, black start and islanding capability not captured in a traditional cost benefit analysis. As a part of the scope of this study, an alternative methodology for reviewing CHP & FC projects in New Jersey was requested to help inform program design and evaluation criteria. The goal of this methodology is to try to capture the full value of DG technologies relative to different end use cases. The model described in this section will help to inform Phase II of the economic analysis, and further the preliminary economic analysis.

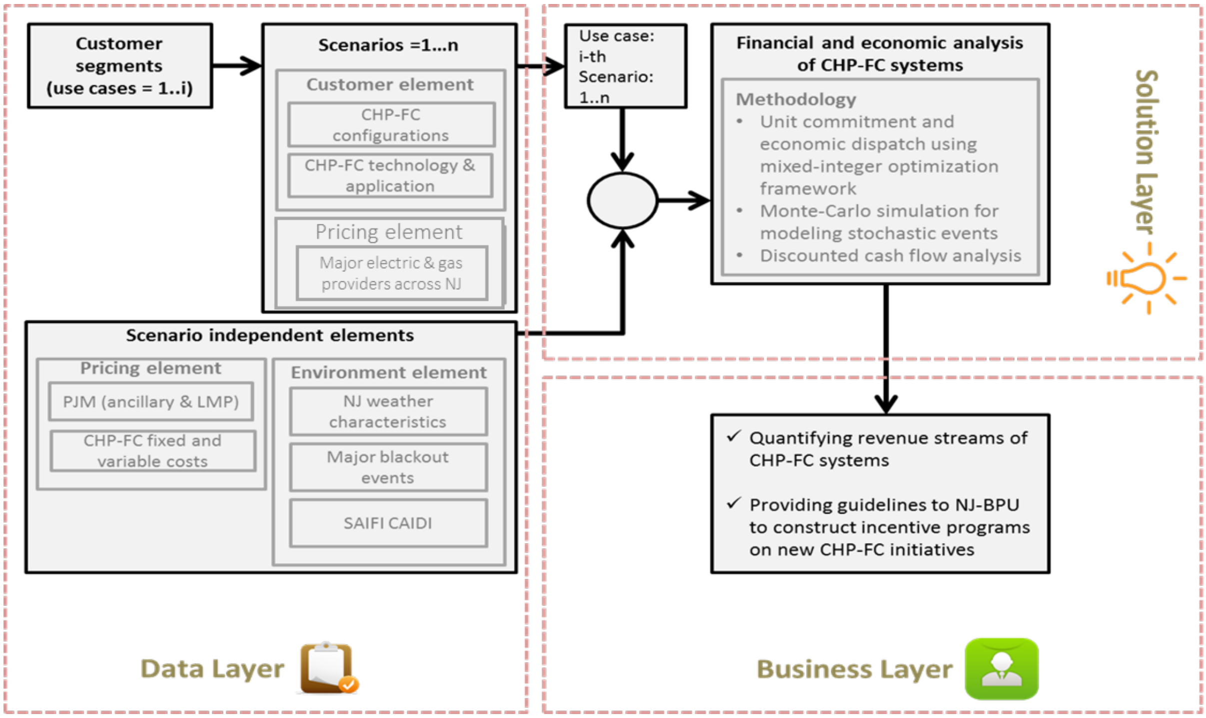
To quantify and confirm the benefits of behind-the-meter (BTM) CHP & FC systems, Rutgers Laboratory for Energy Smart Systems (RU LESS) developed a model of CHP & FC projects to assist BPU staff in identifying how various factors affect the cost-effectiveness and value of CHP & FC projects. Estimated value, determined by the model, feeds into a more regressive cost and benefit analysis. It should be noted that the same methodology can be adopted by applicants to evaluate the operational and economic outcomes of a project on both short- and long-term basis. The design and parameters of the proposed methodology along with its verification and use case studies were performed in Phase I and II.a of this project.

This study was conducted in two phases as follows. The design and parameterization of the proposed methodology were initiated in Phase I. Furthermore, the proposed methodology was applied to electric only fuel cell technology and operational results were demonstrated for the limited use cases. In Phase II more CHP-FC technologies (e.g. FC with heat recovery, FC fueled by biogas, etc.) with more sensitivity analysis and also the interaction between CHP-FC and other distributed energy resources (e.g. storage, PV system, etc.) were studied. We expect to conduct more study in the future to examine broader grid related impacts but this will be dependent upon utility inputs/data related to the distribution system and the locational benefits of fuel cells on the distribution system.

METHODOLOGY

The objective of the model is to estimate the value, generated as a result of CHP & FC installation compared to the base-line (without DG). This value, along with the other cost elements such as project installation cost, will feed into the more regressive cost-benefit analysis model to determine the cost-effectiveness of each individual project. The operation and control of the CHP & FC system is formulated as an optimization problem. **Error! Not a valid bookmark self-reference.** illustrates the proposed methodology framework.

Figure 4-1 Proposed Methodology Framework



Our studies in Phase I and II.a covered natural gas (NG) fueled CHP technology with the following use cases:

A) Four different technologies and prime movers were considered across the use cases:
   a. Fuel cell (SOFC) without heat recovery
   b. Fuel cell with heat recovery
   c. Micro turbine
   d. Reciprocating engine

   Note that in Phase I FC without heat recovery was studied and according to our findings electric only FC without heat recovery turned out to be not cost effective. In phase-2 other technologies of CHP have been investigated in order to find the important factors in financial and environmental impact of CHP system.

B) The operational value of CHP for eleven (11) different facilities were studied and reported. Different facilities have different energy profiles with different characteristics, and our hypothesis was that characteristics of these profiles have significant impacts in the value a CHP project can generate.

C) Two levels of CHP sizing (rated capacity – kW) were included in our experiments in Phase I.a: a) Sizing based on thermal demand b) Sizing based on electricity demand.

D) Three different EDCs and two different GDCs with corresponding tariffs and rate structure were investigated. Different elements of cost structure for electricity (e.g. energy charges, demand charges, etc.) and gas (e.g. per therm charges, per demand therm charges, per balancing therm charges, etc.) were included in the analysis. Incentives provided by these entities were also included in our studies.

E) Operational value of CHP is investigated in two applications:

   a. Energy Bill Management (EBM)
   b. Backup system during the outage events (Resiliency)

In the future, the methodology may examine broader grid related impacts but this will be dependent upon utility inputs/data related to the distribution system and the locational benefits of fuel cells on the distribution system.

The following assumptions were made:

- Annual energy cost saving per installed capacity ($/ kW) is our main measure for the financial evaluation of CHP system.

- Dividing the installation cost per capacity by the annual energy cost saving per installed capacity results in approximation of simple pay-back-period in years. Also, pay-back-period considering Investment Tax Credit (ITC) is calculated as a financial measure.

- Percentage of served critical load during outage events is a good measure for resiliency application evaluation. Since power outage is a random and stochastic event, multiple scenarios of outage are simulated and mean value and standard deviation of percentage of served critical load are reported.

DESIGN OF CORE CASES AND SENSITIVITY SCENARIOS

The intent of the scenario analysis is to enable evaluation of financial and resiliency factors associated with a set of comprehensive case studies. The scenarios are structured to have use cases and sensitivities around those use cases. Use cases will be defined based on two exclusive parameters, namely, customer segment (segments with the high adoption rate of CHP & FC such as: hospital, school, residential multi-family building, hotel, warehouse and etc.) and location (NJ Electricity and Gas providers). Within each use case a set of extensive sensitivity scenarios will be designed. Factors included in sensitivity scenarios are: "CH & FC application", "system sizing configuration", "technology" and "Electric & Gas tariff". Different technologies with different prime movers (such as Micro turbine, Reciprocating Engine, Fuel Cell and etc.) and different fuel classes (such as Natural gas, biogas and etc.) will be included in sensitivity scenarios.

Customer segments

Different customer segments are considered in this study. These segments include both critical and non-critical customers. Hourly (or sub-hourly) electricity and thermal demand profiles are required for financial analysis. Moreover, the critical demand profile for each customer segment is required for resiliency evaluation. In cases where real demand data are not available EnergyPlus building simulations will be used to generate the needed data.

Location (NJ Electricity and Gas providers)

Different locations based on major Electricity and Gas providers' territories in NJ are defined for core cases. Different Electricity and Gas provider companies have different rating structures for electricity and gas, which affect the calculation in the financial evaluation process. Three different electricity utilities (PSEG, JCPL and ACE) and two different gas utilities (PSEG and NJNG) with corresponding tariffs and rate structure were investigated in this phase. Different elements of cost structure for electricity (e.g. energy charges, demand charges, etc.) and gas (e.g. per therm charges, per demand therm charges, per balancing therm charges, etc.) were included in our analysis.

GENERAL OPERATION MODEL

The objective of operation model is to simulate optimal operation of facilities with CHP-FC installations over a period of time (a year or more). The model will account for statistical nature of loads and various technology features and operational conditions of CHP-FC. The model also accounts for different application scenarios. Detailed description of mathematical programming formulation including objectives and constraints for each CHP-FC application is provided next.

a. Electric Bill Management (EBM) in normal operation

The objective of EBM optimization is to maximize the cash flow by reducing total energy cost and monthly demand charges (as well as increasing net metering revenue to model cases where the use of a NJ Class I RE biofuel is proposed). The objective function and operational constraints are as follows:

Objective function is to minimize total cost composed of:		
1 -Total energy cost a) Electricity cost b) Gas cost	2- Monthly demand charges	3- CHP & FC operation cost a) Regular operation cost (fuel cost) b) Start up cost c) Shutdown cost

Operational Constraints are:	
1-Constraints of power balance a) Meet electrical demand completely b) Meet thermal demand completely	2- Constraints on CHP & FC devices a) Upper and lower boundaries for the rate of changes in the CHP & FC output power b) Upper and lower limit on CHP & FC output power

b. Backup system during the outage events (Resiliency)

The objective is to serve the critical load (CL) during outage hours. A penalty structure in the form of $/kWh of unserved CL is specified to minimize the unserved critical load to the extent possible. A review of the results of a sensitivity analysis around the penalty may result in a recommendation for optimal incentive level for an islanding equipment adder. Net metering is disabled since the system is disconnected from the grid. The operational constraints are as follows:

Objective function includes two parts:	
1 - Maximize the served critical load * The unserved critical load will be penalized by a big number	2 - Minimize CHP & FC operation cost a) Regular operation cost (fuel cost) b) Start up cost c) Shutdown cost

Operational Constraints are:	
1 - Constraints on critical demands a) Critical electricity demand b) Critical gas demand	2 - Constraints on CHP & FC devices a) Upper and lower boundaries for the rate of changes in the CHP & FC output power b) b) Upper and lower limit on CHP & FC output power

Required parameters and data for optimization problem are listed next.

Parameters

- CHP & FC electric efficiency
- Maximum CHP & FC output power (kW)
- Minimum threshold for CHP & FC output power (kW)
- Upper limit on ramp rate for CHP & FC (kW)
- Lower limit of ramp rate for CHP & FC (kW)
- CHP & FC start-up cost[168]
- CHP & FC shutdown cost

Input data

- Electricity rate structure (electricity tariff)
- Gas rate structure (Natural Gas (NG) tariff)
- Fuel cost (it could be natural gas or any other fuel, according to CHP & FC technology)
- Facility electricity demand profile (sub-hourly or hourly)
- Facility thermal demand profile (sub-hourly or hourly)
- Facility critical electricity demand profile (sub-hourly or hourly)
- Facility critical thermal demand profile (sub-hourly or hourly)

Synopsis of Findings

Our up-to-date findings are listed below with some selected illustrative results:

a) Phase 1- Electric-only FC

- **Finding 1**: CHP-FC generates more value in facilities with less variation in the daily energy profile. Our analysis shows that facilities such as full-service restaurants, hotels, stand-alone retail and strip-malls have higher $/kW because of the low variation in their daily energy demand (similar load profiles for weekdays and weekend).

- **Finding 2**: We assumed two CHP-FC sizes and we found out that increasing rated capacity of CHP does not necessarily lead to higher $/kW annual value.

- **Finding 3:** CHP-FC system with higher rated capacity enhances the resiliency capability and environmental benefit of a project. Higher rated capacity results in more on-site generated electricity and lower purchased energy from the main electricity grid, which reduces the amount of emission (i.e. SO2, CO2 and NOX).

- **Finding 4:** Incentives offered by GDC companies to DG installer improves the value of CHP projects. Most of the cost-effective CHP projects in our experiments are located in the territory of a GDC, which incentivizes DG installed customer by assigning a lower NG rate.

[168] CHP-FC start-up cost Is the cost of fuel required during the start-up time

- **Finding 5:** Our experiments for the eleven (11) facilities examined in this study indicate that FC without heat recovery system is not cost effective in most of the use cases, since the approximate pay-back period (PBP) (without tax credit and incentive) is more than 10 years. However, in facilities with low demand profile variation and in the presence of an incentive from utilities (i.e. lower natural gas rate) and the Federal ITC, FC without heat recovery begins to be cost effective. The following figures show annual generated revenue and approximate PBP with ITC for the current set of experiments.

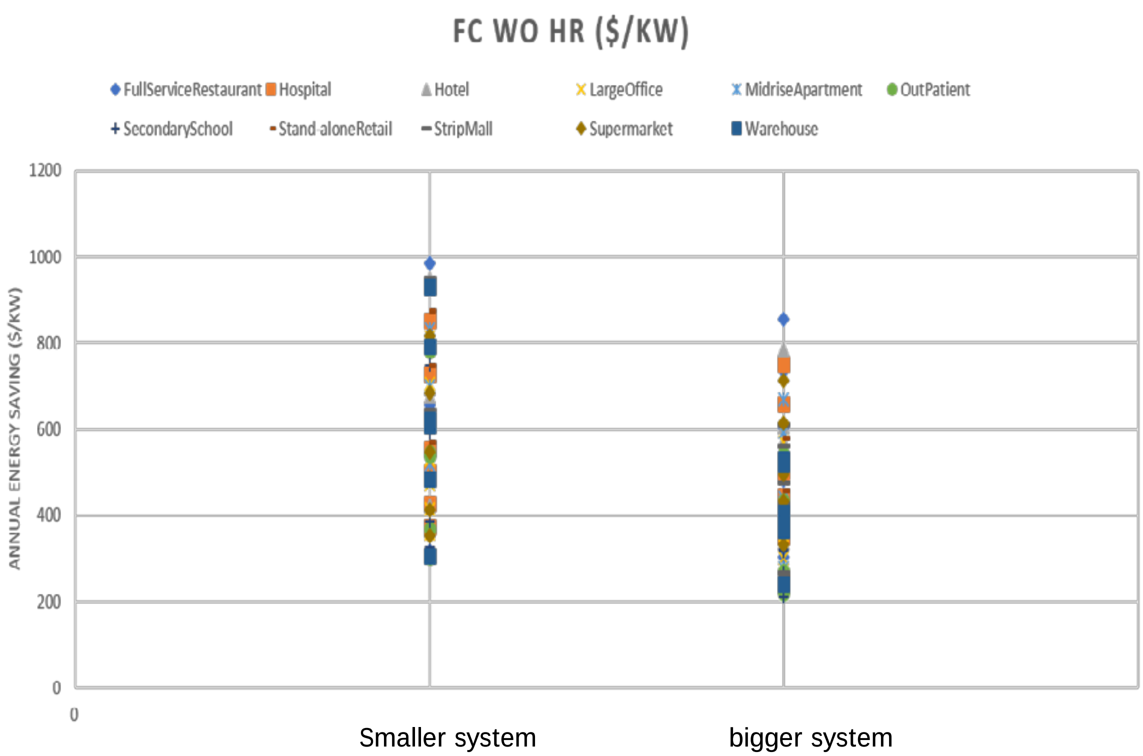


Figure 4.2 - FC without HR annual value ($/kW) in different facilities

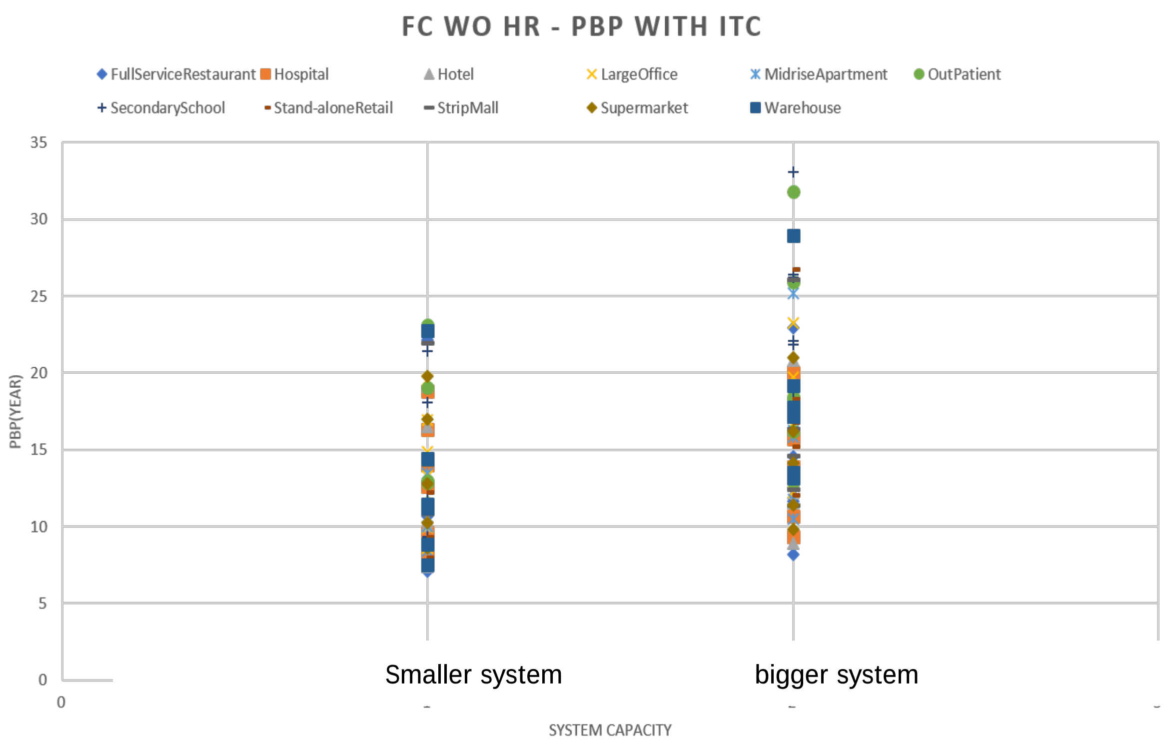


Figure 4.3 - FC without HR PBP in different facilities

b) Phase 2.a – FC with heat recovery, Micro-Turbine and Reciprocating Engine

- **Finding 6**: Recovering and using wasted heat improves the financial and environmental impact of CHP projects. Using recovered heat results in lower energy cost and also lower emission generation.

- **Finding 7**: Heat recovery has significant impact on facilities with highly-correlated electricity and thermal demand. In facilities with positively correlated electricity and thermal demand profiles, increasing and decreasing in demand level occurs simultaneously in both electricity and thermal demands. This helps the CHP-FC facility to maximize the usage of recovered heat and increase the value of the project.

The following figures show the annual value ($/kW) and PBP (with ITC) for FC with recovery projects.

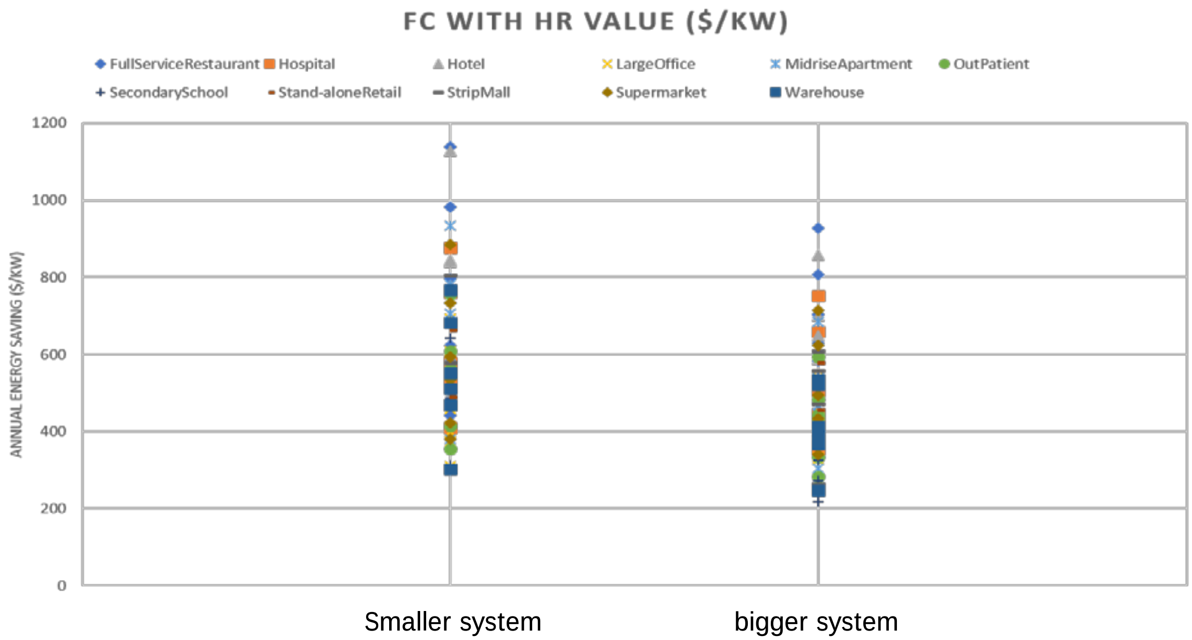


Figure 4.4 - FC with HR annual value ($/kW) in different facilities

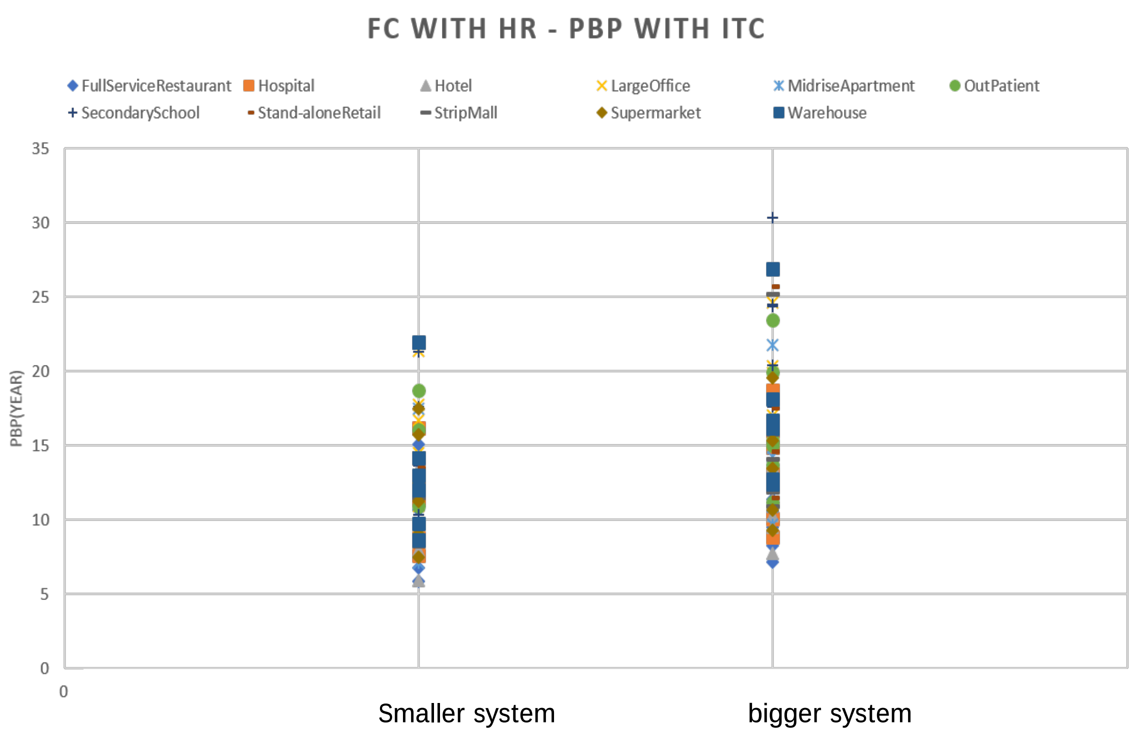


Figure 4.5 -FC with HR PBP in different facilities

- **Finding 8**: Different prime movers have different operational characteristics such as efficiency. CHP systems with more efficient prime mover generate higher value. In our study, FC has the highest efficiency and value ($/kW) if integrated with reciprocating engine or micro-turbine[169].

- **Finding 9**: In PBP calculation, investment cost and ITC of prime mover are also important besides the generated $/kW value. Investment cost and ITC[170] for micro-turbine and reciprocating engine are lower than FC, however FC generates more $/kW. Considering all these three factors is crucial in PBP calculation.

- **Finding 10:** Prime movers with higher efficiency results in more emission reduction.

  Note that current analysis of micro-turbine and reciprocating engine has been conducted based on the simulation of three facilities. More facilities will be analyzed in the near future.

Important Remarks

The above analysis can be extended to more use cases and applications and enormously benefit from actual field data, such as commercial and industrial facilities. This methodology can be adopted by applicants to evaluate the operational and economic outcomes of a project on both short- and long-term basis. Utility participation and coordination in obtaining distribution level data is critical to estimating the full value of DG and net economic benefits related to deferred investments in transmission and distribution systems.

[169] http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf
[170] https://energy.gov/savings/business-energy-investment-tax-credit-itc

5

PHASE I RECOMMENDATIONS

The Phase I recommendations draw on the key findings and insights presented throughout this report and are detailed below. These recommendations are preliminary and are subject to change based on the findings of Phase II of the project. Phase II will provide a more detailed exploration into the performance of CHP and fuel cell systems and the evaluation methodology. A refined set of recommendations will follow the close of Phase II. The recommendations listed below are based solely only on the research completed for Phase I.

1. **Clearly define primary program objectives, based on the NJ EMP and NJ NJCEP Strategic Plan[171].** These objectives should then inform the program design. The primary program objective may be to 1.) promote strictly CHP (i.e. waste heat recovery), 2.) incentivize technologies that provide maximum energy saved per dollar, 3.) incentive systems that deliver net economic benefits, 4.) reduce the cost of energy for all customers, 5.) achieve high generation goals for CHP, 6.) advance emerging or underutilized technology, 7.) promote a diverse portfolio of new, clean, in state generation 8.) achieve high emissions reduction goals[172] or 9.) reduce peak demand. The objective or objectives that are selected by the Board will inform the types of analyses that are used to evaluate DG and the amount and structure of any incentives.

    - If the primary goal is 1-4, than the program would yield a more narrow definition of eligible technologies and would likely exclude fuel cells without heat recovery. While the 4-9 would direct a more broad definition of eligible technologies, potentially including fuel cells without heat recovery.

2. **Change the program structure and incentives to closely align with a clearly defined primary program objective.** The following are potential program attributes that can be adjusted based on a clearly defined program objective. These are grounded on observations from leading programs across the country. These are highly subject to change after Phase II is completed and the primary program objective is defined.

    - *Create technology agnostic incentives.* The more simplified the incentive offering, the less education and administration required for program participants. Additionally, one technology is not promoted more than another, unless program objective directs otherwise. The California SGIP and NYSERDA programs have

[171] The NJCEP Strategic Plan is an ongoing planning process to improve the program offerings for the NJCEP. The goals are to update portfolio elements which are outdated and not reflective of national best practice and to optimally allocate precious budgetary resources across programs. The preliminary plan is guiding the development of refinements to the existing programs for FY17; the fuller strategic planning process – which requires both more time and significant input from the BPU – will set the stage for comprehensive change in direction for FY18 and beyond. There will be five steps to the strategic planning process: 1.) Setting policy objectives, 2.) Establishing clear detailed operating principles, 3.) Conducting baseline studies and other market research, 5.) Establishing portfolio-level targets, 5.)Plan a portfolio of programs. On-going evaluation and timely market research will also be incorporated into the planning process.

[172] For example, California clearly states that GHG emission reductions is the primary goal of the program, so any on-site generating units that have that to meet a GHG gas threshold in order to receive an incentive. The program uses the SCT cost effectiveness test as a secondary consideration.

technology agnostic incentives diversify when needing to tailor to specific technology needs or goals of the state, i.e. bonus incentives for bio gas etc.

- *Consider adjusting the minimum efficiency requirement to align with the established program objective.* Currently the program in New Jersey has an efficiency requirement of 65% LHV for CHP and FC with heat recovery technologies.
    - For example, if the objective of the program is promoting on-site generation in general or achieving high emission reduction goals (such as in New York and California), a lower program wide or dual efficiency requirement (i.e. what the NJ program had previously) would be recommended. If the objective of the program is to incentivize the most cost effective projects or to promoted CHP (i.e. heat recovery), than a higher minimum efficiency would be recommended, such as programs Maryland and Massachusetts where cost effectiveness and high efficiency are priorities.
- *Express the minimum efficiency requirement in HHV, Higher Heating Value, rather than LHV, Lower Heating Value, to align better with what other jurisdictions and sources report, as well as, HHV is more appropriate for CHP applications*. Currently, NJ CHP-FC program expresses the efficiency requirement in LHV. Most programs express the minimum efficiency requirement as HHV, Higher Heating Value, as opposed to LHV or Lower heating Value. HHV is a more inclusive efficiency rating because the calculation accounts for all available thermal heat, whereas LHV excludes heat from water vapor. HHV is more appropriate for CHP applications because of the inclusive nature of the efficiency calculations.
- *Consider adjusting the incentive structure type.* Other types of incentives include a design incentive or performance incentive. Providing more involvement and assistance in the front and back end of project will improve the chances of operational success.
    - T*he performance incentive can help to ensure the longevity of the project.* California SGIP has 50% of the incentive given at installation, and 50% given over 5 years as a performance incentive for a project over a certain size threshold.
    - *Consider requiring a feasibility study or bonus incentive for those projects that include a feasibility study.* A feasibility study will help ensure that system performance and cost expectations are addressed, and a system is sized correctly for the electrical and thermal needs of the site.
- *Add bonus incentives for renewables (biogas) and/or critical facilities*. If one of the objectives is to promote renewables, this would generate market interest and movement for renewable DG projects. Using an adder on top of an existing incentive is more streamlined than offering an entirely separate incentive for just for renewable DG projects. If one of the goals is resiliency as it is in New York, adding a bonus incentives for projects at critical facilities (hospitals, police stations, communication facilities etc.) will promote that policy objective.

3. **Obtain and maintain operational data from project sites.** Limited operational data makes it difficult to evaluate cost efficiency based on actual system performance and to tie incentives to performance. Consider creating a sustained database where operational data is tracked and easily accessed. The state run programs in New York and California maintain comprehensive performance databases that are supported by more thorough reporting

requirements. More operational data would better inform project evaluations and program direction.

- Consider requiring applicants to submit an annual report on system performance for up to 5 years after commissioning. In addition, consider requiring that applicants must respond to surveys and performance inquiries for evaluation purposes and require applicants to notify the program administrators if the system is going to be retired. The more readily available data program administrators have the better the chances are for success of the individual projects and the program as a whole. If the incentive structure is adjusted to include a performance component that where performance data is submitted and payment for generation is received over multiple years, the system life of the project can be extended.

4. **Consider exploring alternatives and/or additions to the current evaluation methodology**, depending on the defined program objectives. The program objectives will direct which economic metrics should be used to evaluate individual projects and the overall portfolio

    - Consider the use of an alternative evaluation methodology such as a GHG threshold screening (California SGIP), a weighted criteria analysis (such as in Illinois, or other type of evaluation methodology that can account for broader grid benefits (and costs) such as resiliency, emission reductions, transmission and distribution investment savings locational benefits etc. of DG technologies may yield a different results and recommendations.

        - The results of the preliminary fuel cell economic analysis using the five CBA metrics and simple payback evaluation methodologies indicate that there is no net benefit for fuel cells without heat recovery. The analysis points out that the current methodology of simple payback may overestimate the economic value of these capital intensive DG technologies and does not account for potential benefits like resiliency.

        - The current evaluation does not incorporate the federal investment tax credit due to the timing of applications and expiration of the credit. Additional analysis that includes the federal ITC was conducted afterwards and is to be included in future report iterations. More analysis is needed to properly consider the Modified Accelerated Cost Reduction System (MACRS), and any applicable property tax benefits.

5. **Consider evaluating projects on an individual basis using one of the CBA metrics as an alternative or additional method,** based on defined program objectives**.** According to the literature review of other programs across the country, a common practice is to evaluate projects on an individual basis using the TRC metric.

    - If the primary objective is to incentivize the most cost effective projects, consider evaluating projects on an individual basis using the TRC. Many programs across the county use the Total Resource Cost test to evaluate projects on an individual basis. Programs in Rhode Island, Illinois, Maryland, Maine, and Massachusetts utilize the TRC test to screen individual project applications for the delivery of a program incentives.

    - If the non-energy benefits, like emission reductions or resiliency, are deemed a program objective when evaluating technologies, the use of the Societal Cost Test (SCT) should help to incorporate those concerns. In California specifically, a GHG is the primary assessment tool for project approval, and the SCT is secondary tool used to review projects and to review technologies at a higher level as a part of the program's impact evaluations. California calculates the CBA using the TRC inputs, but applies a societal discount rate that better values system lifetime benefits more.

- If choosing either CBA metric, it is important to note that budget limitations may prevent the funding of all projects whose SCT or TRC yield net benefits; thus it is important to not only compare CBA metrics for each project but also to other projects across technologies.

A

LITERATURE REVIEW APPENDICES

The embedded document contains a detailed summary of the review programs and the corresponding program attributes and sources.

State	Program Administrator	Program Title	Program Status	Program Parameters	Target Market	Technologies Included
New Jersey	State	CHP and Fuel Cell Incentive Program	Current	Minimum efficiency of 65% with waste heat utilization, must have 10 year all inclusive warranty or 10 year service contract. Projects must meet simple payback requirement of 10 years to receive incentive.	Commercial, Industrial, Local Government, Nonprofit, Schools, State Government, Federal Government, Agricultural, Multifamily Residential, Institutional	Combined Heat & Power: RE and non-RE fuels - gas internal combustion, gas combustion turbine, mirco-turbine, fuel cells with heat recovery, waste heat to power
Alaska	State	Renewable Energy Grant Program	Recently expired- Round 9 applications were due 9/15 for final grant awards in 7/16.	Grant program for reconnaissance studies, energy resource monitoring, feasibility studies, and final design and construction of an eligible project. The program is designed to produce cost-effective renewable energy for heat and power to benefit Alaskans statewide.	Electric utilities, Independent power producers, Local government or government entities	Project with direct use of wind, solar, geothermal, waste heat recovery, hydro thermal, wave, tidal, biomass, landfill gas or digester gas, or fuel cells from RE or non-RE.
Arizona	Southwest Gas Corporation	Combined Heat & Power Program	Expired	Minimum efficiency of 60%, must have waste heat recovery, 12 months of utility bills, and a feasibility or preliminary economic study of the proposed project. Projects evaluated on fuel efficiency, and emission and water savings.	Commercial, Industrial, Federal Government	Any CHP with any fuel source, must have waste heat recovery.

California	State - California Public Utilities Commission	Self-Generation Incentive Program	Current - 1/1/21	Minimum electrical efficiency of above 40% HHV for conventional CHP and Fuel Cells operating on non-RE or meets waste heat utilization. Conventional CHP and fuel cells must operate on non-RE and must meet GHG emission requirements. Maximum incentive is the lesser of $5 million or 60% of eligible project costs. Payment is capped at 3 MW, projects above 1 MW will receive a diminished incentive. Projects must meet greenhouse gas threshold in order to receive incentive	Available to all major participating IOU customers	Renewable and waste heat recovery: wind turbine, waste to heat power, pressure reduction turbine; CHP with no renewables: combustion, mirco-turbine, gas turbine; emerging tech: advanced energy storage, fuel cell CHP or electric only.
Connecticut	State - CT Green Bank	Combined Heat & Power Pilot Program	Expired - 7/08/13 - 2/27/15 Second solicitation	Systems of 5 MW of less, electricity production from the CHP unit should not exceed 100% of the average load demand of the facility based on the past 12 months usage data, minimum efficiency of 50%	Critical facilities in Commercial, Industrial, Local Government, Nonprofit, Schools, State Government, Federal Government, Institutional	Any CHP with any fuel source. Must have waste heat recovery. Fuel cells allowed
Ohio	Dayton Power and Light	Custom Rebate Program	Current	Minimum efficiency requirement of 60% LHV, payback based on electricity cost savings under 7 years, installed in territory.	DP&L business and government customers	Any CHP with any fuel source. Must have waste heat recovery. Fuel cells allowed
Illinois	State	Public Sector Combined Heat and Power Pilot Program	Expired in early 2017. The 12 months of operation of the CHP system must be completed by the conclusion of the 2014-2017 three-year approved program plan (May 31, 2017).	Minimum efficiency of 60% HHV with at least 20% of the system's waste heat energy output in the form of useful thermal energy utilized in the facility. Eligible CHP/WHP projects must pass the Total Resource Cost (TRC) test at the "measure" level.	Local Government, Schools, State Government, Federal Government, Institutional	Conventional CHP or CHP with waste heat to power, the Conventional CHP system must be operated utilizing natural gas and the waste heat used to replace heat generated from a natural gas fueled boiler/furnace.
	Com ED	CHP Pilot Program	Current	Newly designed and constructed Conventional CHP systems with annual fuel use efficiencies of at least 60% (HHV) with at least 20% of the system's total useful energy output in the form of useful thermal energy. These systems will have a net zero annual export of power to the grid. Simple payback on the investment is greater than 2 years (without incentives). Meet the TRC with a score of 1 or greater. Individual projects that score less than 1 on the TRC may be approved by the DCEO	The CHP program is for both private commercial and nonprofit facilities, but is not applicable to public facilities that use DECO incentive programs instead of Smart Ideas	Targets larger non-public sector C&I customers in the ComEd service territory. Generally those customers above 1,000 kW in demand. Smaller CHP projects, although not qualifying for Feasibility Study and Interconnection co-funding, are nonetheless eligible for ComEd custom program

Maine	State - Efficiency Maine	Custom Distributed Generation Projects	Current - until funds are exhausted	Minimum efficiency of 60% LHV (total electrical output + total thermal output utilized)/total fuel input. Must have 1 TRC or higher. Total installed cost of $4,000/kW of installed capacity or less. Projects that have a simple payback under 1 year, after factoring program incentive, are not allowed. Needs to have serviceable thermal loads and/or thermal storage capacity	Commercial and Industrial	Any CHP system, needs to have serviceable thermal loads and/or thermal storage capacity that allows for utilization of nearly 100% of the thermal output available from the CHP installation on a continuous basis.
Massachusetts	State	DOER - Community Energy Resiliency Initiative	Expired - 2013-2015		Critical facilities, defined as buildings or structures where loss of electrical service would result in disruption of a critical public safety life sustaining function.	Distributed RE generation (electric and heating/cooling systems); CHP and district energy systems; High efficiency fuel cells; Energy storage (flywheels, batteries, electric vehicles, Hot/cold water storage); Energy management systems that enable load shedding used to isolate and serve critical loads during an event; Technology used for DG operation in island mode; Controls, switches, inverters and smart inverters; Microgrids
		Mass SAVE - Combined Heat and Power Program	Current	Level 1 - No minimum efficiency, Size must not exceed thermal and/ or electrical load of the building assuming implementation of efficiency measures. Level 2 - minimum efficiency 60%. Level 3 - minimum efficiency 65%. Level 2 and Level 3: Sized to follow thermal loads of the building post implementation of all efficiency measures with a simple payback of 3 years or less. Program administrators run BCA	All owners of CHP systems are eligible, but the best applications are typically those with high annual hours of operation with near full use of the thermal output, including process industry (24/7) operation, as well as commercial applications such as hotels, hospitals, nursing homes, schools, colleges, laundries, health facilities and multi-unit apartments.	Any CHP or FC system and fuel source that recovers waste heat

New York	State- NYSERDA	CHP Program	Current - accepting applications till 2018. CHP Acceleration merged with CHP Performance.	Maximum size of 3MW systems, A catalog (pre qualified equipment suplied by approved vendor) or "Custom Approach" option added to accommodate customers seeking CHP Systems 1MW and larger whose needs are not being met by the catalog entries. Minimum of 60% HHV. Not accepting systems over 3 MW after 12/2016. Feasibility study required.	Commercial, Industrial, Federal Government	CHP with pipeline natural gas, propane, or compressed natural gas.
		RPS Customer Sited Tier Fuel Cell Program (Small)	Expired - funds exhausted in beginning of 2016	Small - <25 kW, annual capacity factor >=50%. Actual net annual output = total verified electrical energy delivered by system.		Fuel cell with or without heat recovery
		RPS Customer Sited Tier Fuel Cell Program (lLarge)	Expired - funds exhausted in beginning of 2017	lLarge >25 kW, annual capacity factor >=50%. Actual net annual output = total verified electrical energy delivered by system.		Fuel cell with or without heat recovery
Pennslyvania	State - Department of Community and Economic Development	Alternative and Clean Energy Program (ACE)	Current - not accepting applications at this time		A business, an economic development organization, or a political subdivision including municipalities, counties and school districts.	Alternative energy system: waste coal, biomass, wind energy, geothermal technologies, clean coal technologies, waste energy technologies, large-scale or low-impact hydro, biologically derived methane gas, fuel cells, coal mine methane, or by-products of the pulping and wood manufacturing process
	First Energy	Combined Heat and Power Program	Current	Minimum efficiency of 65%- relationship of useful electric and thermal output verses the fuel input. Must be determined to be cost effective using the Total Resource Cost (TRC) test. Must be new and installed after June 1, 2016 and must be installed and operational by Dec. 31, 2021.	Commercial, Industrial, Governmental and Institutional customers of FirstEnergy's Pennsylvania utilities	Turbines or internal combustion engines coupled to generators where waste heat is used to support the customer's process. The preferred fuel source is natural gas or biogas.
	PECO	Smart Ideas: Non-Residential Energy Efficiency Rebate Program	Expired - May 31, 2016	Steam Turbine - 80%, Reciprocating Engine - 70%, Gas Turbine - 70%, Micro-turbine - 65%, Fuel Cell - 55%	Business and multi-family housing customers of PECO	CHP with any fuel type or generation component
		Combined Heat and Power Program	Current	Steam turbine: 80% » Reciprocating engine: 70% » Gas turbine: 70% » Micro turbine: 65% » Fuel cell: 55% » Other: 60%. Participants must show proof of a five-year (or greater) warranty. Must have heat recovery	Commercial and Industrial	Reciprocating engines, seam turbines, gas Turbines » Micro-turbines, fuel cells, bottoming cycle systems

Rhode Island	National Grid	Combined Heat and Power Program	Current	Minimum efficiency of 55% HHV. Projects must undergo BCA utilitizing methodology outlines by RI PUC. Must have ratio of 1 or greater to receive funding	Commercial, Industrial	Reciprocating engines, gas/combustion turbines, back pressure steam turbines, and fuel cells that recover waste heat. A CHP system can use any type of fuel.

State	Program Administrator	Program Title	Electric Only Fuel Cell Eligibility	Incentive Structure Type	Incentive/Finance Structure	Budget	Program Performance/ Participation	Link to Program Site
New Jersey	State	CHP and Fuel Cell Incentive Program	Combined Heat & Power: RE and non-RE fuels - gas internal combustion, gas combustion turbine, mirco-turbine, fuel cells with heat recovery, waste heat to power	Tiered capacity payment	Incentive varies by system type and size. Incentives range from $350/kW to $2,000/kW. Incentives capped at 30-40% of total project cost. Cap per project range from $2-3 million depending on system type.			http://www.njcleanenergy.com/commercial-industrial/programs/combined-heat-power/combined-heat-power
Alaska	State	Renewable Energy Grant Program	Eligible	Project cost payment	Provides funding for phase 1 reconnaissance, phase 2 feasibility and conceptual design - phase 1 & 2 limited to 20% of phase 4 costs, phase 3 final design and permitting- 20% of phase 4, phase 4 construction and commissioning - $2 million per projection.	Round 8 - $11.5 million in 2015, Round 7 - $20 million in 2014		http://www.akenergyauthority.org/Programs/Renewable-Energy-Fund/Rounds#Round%209
Arizona	Southwest Gas Corporation	Combined Heat & Power Program	Not eligible	Capacity payment	Rebate, $400/kW - $500/kW up to 50% of the installed cost of the project.		No participants in 2015	http://www.pacificchptap.org/data/sites/1/events/2012-01-26/Camp-Southwest_Gas_CHP.pdf
California	State - California Public Utilities Commission	Self-Generation Incentive Program	Eligible if CHP systems and Fuel Cells are operating on non-RE. Must meet either waste heat utilization requirements or minimum electric efficiency. Also systems must meet GHG emission requirements.	Tiered capacity payment w/ performance	Incentive per W capacity system. Projects >30 kW receive 50% of incentive at completion, other 50% as performance incentive for 5 years. Step 1: $0.60 & with bio gas $1.20. Step 2: $0.50 & with bio gas added $1.10. Step 3: $0.40 & $1 with bio added. Added incentive of 20% is available for installation by a California supplier.	2015: $83 million. 2016: additional $77 million released with 50% released initially and the other 50% withheld for market balance purposes. 75% of budget allocated to energy storage, 25% to generation tech.	AES - 595 projects, Fuel Cell CHP - 86 projects, Fuel Cell electric - 93 projects, Gas Turbine - 11 projects, Internal Combustion - 253 projects, Mirco-turbine - 143 projects, PV - 920 projects, Wind - 16 = 2,117 total projects with 451 MW in capacity since 2001.	http://www.cpuc.ca.gov/sgip/
Connecticut	State - CT Green Bank	Combined Heat & Power Pilot Program	Not eligible	Hybrid capacity payment	Loan, grant, or PPA - performance based incentive, maximum of $450/kW - incentive varies based on technology, size, efficiency, and install economics.	$6 Million	0.6 MW of biomass, 4.6 MW CHP, 14.8 MW Fuel Cell of installed capacity between FY 2012-2015	http://www.energizect.com/your-business/solutions-list/Combined-Heat-Power

Ohio	Dayton Power and Light	Custom Rebate Program	Not eligible, must have heat recovery.	Capacity payment with energy generation payment	$0.08/kWh generated paid during first year project is commissioned. The higher the LHV the larger % of the calculated incentive is to be received. Capacity payment of $100/kW paid at project completion. Rebate limited to 50% of total design and construction costs, capped at $500,000.			https://www.dpandl.com/save-money/business-government/custom-rebates/chp-rebates/
Illinois	State	Public Sector Combined Heat and Power Pilot Program	Not eligible, ruled out by efficiency requirement and must have heat recovered	Project cost payment with performance	Grant: 3 Tier Incentive-$75/kW. Capacity Construction Incentive-$175/kW. Capacity Performance Incentive-$0.06-0.08/kWh (Waste heat to power $0.08) of useful electric energy produced. Total incentive is capped at lesser of $2 million or 50% of project cost.			https://www.illinois.gov/dceo/whyillinois/TargetIndustries/Energy/Pages/CHPprogram.aspx
	ComEd	CHP Pilot Program	Not eligible, ruled out by efficiency requirement and must have heat recovered	Project cost payment w/ performance	50% of feasibility assessment costs up to $25,000. 50% of interconnection fee up to $25,000. Performance Incentive: $0.07/kWh based on review of 12 months of metered data and capped at $2 million. Nicor Gas also offers an incentive of $1/annual therm for project sites in their service territory.			https://www.comed.com/SiteCollectionDocuments/WaysToSave/Business/PY9_CHP_flyer_v03.pdf
Maine	State - Efficiency Maine	Custom Distributed Generation Projects	Not eligible, ruled out by minimum efficiency level and requirement for servicable thermal load	Project cost payment	Minimum of $100,000 to a maximum of $1 million per facility (up to 50% of the total project costs). Incentives < $200,000 will require a formal contract with the Efficiency Maine Trust. Incentives will not exceed $0.28/kWh of validated annual reduction in grid supplied energy.			http://www.efficiencymaine.com/custom-distributed-generation-projects/

Maryland	State - Maryland Energy Administration	MEA CHP FY17 Grant Program	Not eligible	Capacity payment	Grant - first come first serve, ranges from $425/kW to $575/kW (based on the size of the CHP system), capped at $500,000 per project.	$4.025 million. Up to $1.525 million initially reserved for cost effective CHP energy efficiency projects in industrial facilities; Up to $1.5 million initially reserved for energy efficient CHP projects that also increase resiliency in critical infrastructure facilities; Up to $1 million initially reserved for projects that leverage biomass or biogas resources as a fuel source in either industrial or critical infrastructure facilities.		http://energy.maryland.gov/business/Pages/MEACHP.aspx
	Baltimore Gas and Electric	Combined Heat and Power Program	Not eligible	Project costs with performance incentive	Design incentive ($75/kW), Installation incentive ($275/kW for projects under 250kW; $175/kW for projects 250kW or greater), Performance incentive ($0.07/kWh for 18 months,) Capacity and performance incentives each capped at $1.25 million.	Spent $1.7 million in 2014	5 participants in 2014, no projects completed in 2015	http://www.bgesmartenergy.com/business/chp
	Delmarva Power, Pepco	Combined Heat and Power Program	All fuel cell types and fuels	Project costs with performance incentive	Capacity incentive: $350/kW for projects under 250kW; $250/kW for projects 250kW or greater. Performance incentive: $0.07/kWh for 18 months. The capacity incentive is capped at $1.25 million and the performance incentive is capped at $1.25 million		No projects completed in 2015, projects expected to come online in 2016, 2017 and 2018	https://cienergyefficiency.delmarva.com/CombinedHeat.aspx, https://cienergyefficiency.pepco.com/CombinedHeat.aspx
	Potomac Edision	Combined Heat and Power Program	No mention of fuel cells, not eligible. Must have waste heat recovered	Project costs with performance incentive	Design incentive: $75/kW. Installation incentive: $275/kW for projects under 250 kW and $175/kW for projects 250 kW and over. Performance incentive: $0.07/kWh for 18 months; three payments following the review of metering data at the end of the sixth, 12th and 18th months following installation		No projects completed in 2015, projects expected to come online in 2016, 2017 and 2018	http://energysavemd-business.com/specialty-programs/combined-heat-and-power/
Massachusetts	State	DOER - Community Energy Resiliency Initiative	CHP and district energy systems; High efficiency fuel cells	Grant	Base grant of $125,000	$40 Million		http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/resiliency/resiliency-initiative.html
		Mass SAVE - Combined Heat and Power Program	Not eligible	Tiered Performance Incentive	Incentives range from $0.075 to $0.115 per annual kWh produced. Tiers delineated by >= or < 150 kW system size and efficiency level. Incentives may not exceed 50% of total project cost.		As of 2012, 25 CHP have been deployed w/ 5.44 MW in capacity	http://www.masssave.com/en/business/eligible-equipment/combined-heat-and-power

New York	State- NYSERDA	CHP Program	Not eligible	Tiered capacity payment	Base incentive varies based on nameplate capacity for upstate and downstate. For example <50kW = $1,000/kW updatesate, $1,200 downstate. Upstates: 10% bonus for target zones in ConEd, 10% bonus for critical infrastructure. Maximum incentive for any one project not to exceed $2.5 million including bonuses	$25 million 2012-2016 budget for CHP Acceleration Program, $50 million 2012-2016 budget CHP Performance Program	51 projects through 2015, for a total of 12.15 GWh for CHP acceleration, 14 projects through 2015 for a total of 469.6 GWh for CHP performance program	http://www.nyserda.ny.gov/PON2568
		RPS Customer Sited Tier Fuel Cell Program (Small)	Eligible	Performance Incentive	$0.15 per net kWh produced for sites with an annual capacity factor <=50% for 3 years after commissioning, max of $20,000 per year per project site, total cap of $50,000 per project	$100,000 per year		http://www.nyserda.ny.gov/Funding-Opportunities/Closed-Funding-Opportunities/PON-2157-Renewable-Portfolio-Standard-Customer-Sited-Tier-Fuel-Cell-Program-small
		RPS Customer Sited Tier Fuel Cell Program (lLarge)	Eligible	Hybrid capacity and performance payment	Phase 1 funds - grid parallel installations even if not island capable = $2,000/kW up to $600,000. Phase 2 funds for project sites that upgrade to island before end of 3rd performance period= $3,000/kW of installed capacity or the remainder of the total project cap ($1 million per installation), whichever is less.		$3.5 million per year	http://www.nyserda.ny.gov/Funding-Opportunities/Closed-Funding-Opportunities/PON-2157-Renewable-Portfolio-Standard-Customer-Sited-Tier-Fuel-Cell-Program-large
Pennslyvania	State - Department of Community and Economic Development	Alternative and Clean Energy Program (ACE)	Eligible	Loan	Amount matching investment required must be at least $1 for every $1 of Program funds awarded by the CFA. Loans shall not exceed $5 million or 50% of the total project cost, whichever is less. Grants shall not exceed $2 million or 30% of the total project cost, whichever is less.			http://www.newpa.com/programs/alternative-clean-energy-program-ace/#.V79Od_krKUk.
	First Energy	Combined Heat and Power Program	Not eligible	Energy generation payment	Incentives are limited to 50% of the total project cost or $0.03/ kWh, whichever is less.			http://energysavepa-business.com/combined-heat-and-power/
	PECO	Smart Ideas: Non-Residential Energy Efficiency Rebate Program	Eligible	Tiered capacity payment with performance incentive	Eligible for up to $1 million, or no more than 50% of total costs. First 500 kW = $300/kW, 500kW-1.5MW=$150/kW. The performance incentive for CHP projects is $0.02/kWh based on the actual electricity generated		To date, incentives paid on 7 CHP projects totaling $3.6 M. Represents 9.5 MW of capacity and over 56,000 MWh net energy generation.	https://webtools.dnvgl.com/projects62/Portals/9/PECO%20Files/PECO_PSOS_Application_2013.pdf
		Combined Heat and Power Program	Not eligible	Tiered capacity payment with performance incentive	Design Incentives are $100/kW. Capacity Incentives are paid on a declining tiered incentive rate by installed capacity and could range between $40/kW and $400/kW. Capacity incentives can be no more than 40% of the project cost up to at capacity incentive maximum. The capacity incentive maximum will be between $400,000 and $1.5 million. Performance Incentives are paid at a fixed $/kWh rate generated during the monitoring period. The fixed rate will be set in the $25 - $75/MWh range		PECO plans to spend approximately $25 million from 2016 to 2020 and achieve approximately 365,535 MWh and 54,871 kW from the CHP Program.	https://www.peco.com/WaysToSave/ForYourBusiness/Pages/OnSite.aspx

Rhode Island	National Grid	Combined Heat and Power Program	Not eligible	Tiered capacity payment	Tier 1 $900/net kW for CHP with annual efficiency >55% and <60%, Tier 2 $1000/net kW for CHP with annual efficiency > or equal to 60%, Tier 3 Reduce the site energy use at least 5% or identified by TA study - $1125/kW for CHP projects with annual efficiency >55% and <60% , Tier 4 Reduce the site energy use at least 5% or identified by TA study - $1250/kW for CHP projects > or equal to 60% annual efficiency. All incentives will not exceed 70% of the installed cost			https://www.nationalgridus.com/RI-Business/Energy-Saving-Programs/Cogeneration

B

COST BENEFIT ANALYSIS APPENDICES

AVOIDED COST ASSUMPTIONS

The Center for Energy, Economic, and Environmental Policy (CEEEP) is providing these assumptions to the Program Administrator for the New Jersey Clean Energy Program for use in its cost-benefit analyses. The data sources and processes for determining these components are also discussed. All assumptions have been derived from independent and publicly available sources in order to be transparent. For previously used avoided cost assumptions please visit http://ceeep.rutgers.edu/publications/.

On August 3, 2015, the U.S. Environmental Protection Agency released the Clean Power Plan to reduce carbon emissions from existing power plants.[173] How New Jersey decides to comply with the Clean Power Plan may impact many of these assumptions going forward. In addition, there have been major recent changes in PJM's capacity market.[174]

Please note that all dollars are nominal unless stated otherwise.

COST-BENEFIT ANALYSIS OF ENERGY EFFICIENCY PROGRAMS

Cost-benefit analysis (CBA) is a tool that compares the monetized costs and benefits of energy efficiency measures, programs and portfolios. It can be used both to inform program managers and regulators as well as employed as a formal decision-making tool that determines which measures, programs or portfolios should be adopted. As an informational tool, CBA should be conducted at the measure, program and portfolio level; decision-makers will therefore be fully informed, but of course retain the ability to consider non-CBA factors as appropriate.

For its full value to be achieved, CBA should be integrated into program planning and evaluation. Program design should reflect the assumptions used in the CBA. For instance, if large savings are assumed in avoiding transmission and distribution (T&D) investments, then the programs should be designed to achieve those savings such as targeting circuits that are highly loaded, etc. Moreover, there may be other policies that need to be put in place to ensure these savings materialize, such as requiring

ELECTRICITY PRICES

Utilities to explicitly account for energy efficiency in their planning. Finally, evaluations should also be aligned with CBA. In the T&D example, an evaluation of both what New Jersey specific avoided T&D costs are and whether actual T&D investments have been avoided as a result of EE should be performed.

[173] http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants#CPP-final
[174] http://www.natlawreview.com/article/ferc-accepts-pjm-capacity-performance-proposal

Any CBA requires numerous assumptions. Many of the needed assumptions can be further developed at increasing levels of detail. There is a tradeoff between time and effort and the additional accuracy that may come from a more extensive analysis. In addition, the level of detailed across assumptions needs to be consistent. Pursuing some assumptions to one level of detail but not others may bias the CBB results.

Retail Electricity Prices: Historic 2014 U.S. Energy Information Administration (EIA) New Jersey retail electricity prices were escalated using an annual price growth rate derived from the EIA Annual Energy Outlook 2015 for the Mid-Atlantic region. On average, the annual growth rate was about 2.3%. The NJ Clean Energy Programs do not distinguish between commercial and industrial sectors, therefore the commercial and industrial prices were averaged based on historic 2014 New Jersey retail electricity sales. Retail electricity prices reported to EIA include the Societal Benefits Charge (SBC)[175], but not the 7% Sales and Use Tax, which CEEEP added.

Wholesale Electricity Prices: Historic 2014 and 2015 New Jersey wholesale electric prices from PJM were escalated based on the annual percent change in the EIA 2015 Annual Energy Outlook Reliability First Corporation/East Electricity Generation Prices. The annual percent change was, on average, about 2.4%. The seasonal peak and off-peak factors were derived using historic 2015 PJM LMP data. Summer is defined as May through September, winter is defined as October through April, on-peak is defined as Monday through Friday 8am-8pm (HB), and off-peak is defined as Monday-Friday 8pm-8am (HB) and weekends and holiday.

[175] The Societal Benefits Charge for electric customers of 3.6% for residential and 4.8% for C&I is included in the retail prices reported to EIA by the utilities.

Table B-1: Retail Electricity Prices and Wholesale Energy Prices (Nominal Dollars)

	Retail ($/kWh)		Wholesale Energy ($/MWh)				
	Residential	***Commercial & Industrial***	***Average Price***	***Summer Peak***	***Summer Off-Peak***	***Non-Summer Peak***	***Non-Summer Off-Peak***
2014	$0.17	$0.14	$55.32	$45.39	$29.66	$83.58	$59.07
2015	$0.17	$0.14	$34.58	$37.03	$23.06	$46.71	$34.50
2016	$0.18	$0.15	$35.00	$37.47	$23.34	$47.28	$34.92
2017	$0.19	$0.15	$32.17	$34.45	$21.46	$43.46	$32.09
2018	$0.19	$0.15	$32.16	$34.44	$21.45	$43.45	$32.09
2019	$0.20	$0.16	$33.45	$35.81	$22.31	$45.18	$33.37
2020	$0.21	$0.17	$35.61	$38.14	$23.75	$48.11	$35.53
2021	$0.23	$0.18	$38.88	$41.63	$25.93	$52.52	$38.79
2022	$0.23	$0.19	$44.59	$47.75	$29.74	$60.24	$44.49
2023	$0.24	$0.20	$46.93	$50.25	$31.30	$63.40	$46.82
2024	$0.25	$0.20	$48.77	$52.23	$32.53	$65.89	$48.66
2025	$0.26	$0.21	$49.84	$53.37	$33.24	$67.33	$49.72
2026	$0.26	$0.21	$51.97	$55.65	$34.66	$70.21	$51.85
2027	$0.27	$0.22	$52.81	$56.55	$35.22	$71.34	$52.68
2028	$0.28	$0.22	$53.86	$57.68	$35.92	$72.76	$53.74
2029	$0.28	$0.23	$55.50	$59.43	$37.01	$74.97	$55.37
2030	$0.29	$0.23	$55.91	$59.87	$37.29	$75.53	$55.78
2031	$0.29	$0.23	$56.66	$60.67	$37.79	$76.54	$56.53
2032	$0.30	$0.24	$57.58	$61.66	$38.40	$77.79	$57.45
2033	$0.31	$0.25	$58.98	$63.16	$39.34	$79.68	$58.84
2034	$0.31	$0.25	$61.04	$65.36	$40.71	$82.45	$60.89
2035	$0.32	$0.26	$62.54	$66.97	$41.71	$84.49	$62.40
2036	$0.33	$0.26	$64.09	$68.63	$42.74	$86.58	$63.94
2037	$0.34	$0.27	$65.79	$70.45	$43.88	$88.88	$65.64

Capacity Prices: New Jersey Utility PJM Reliability Pricing Model (RPM) prices for the four electric utilities (AE, JCP&L, PSE&G and RECO) for 2010 to 2018 were weighted by each utility's historic 2014 peak load[176] to estimate an average New Jersey capacity price. From 2019 to 2037, the capacity prices were escalated based on the EIA projected annual change in U.S. GDP Chain-type Price Index, which is reported in Table B-6. PJM's Forecast Pool Requirement (FPR) is provided in Table B-3; the FPR is a multiplier that converts load values into capacity obligation.[177]

[176] PJM Reliability Pricing Model User Information. Base Residual Auction Results www.pjm.com/markets-and-operations/rpm/rpm- auction-user-info.aspx#Item01; PJM. Historic Load Data.

[177] 2015 PJM Reserve Requirement Study, October 8, 2015, PJM Staff, p. 9 for FPR values and p. 41 for definition of FPR.

Table B-2: Capacity Price (Nominal $/kW-year)

	$/kW- year
2014	$71.00
2015	$59.46
2016	$61.83
2017	$62.39
2018	$73.44
2019	$74.85
2020	$76.34
2021	$77.89
2022	$79.52
2023	$81.15
2024	$82.81
2025	$84.52
2026	$86.27
2027	$88.06
2028	$89.91
2029	$91.78
2030	$93.73
2031	$95.74
2032	$97.79
2033	$99.90
2034	$102.06
2035	$104.28
2036	$106.56
2037	$108.85

Table B-3: PJM Forecast Pool Requirements

Delivery Year Period	*FPR*
2016/2017	1.0953
2017/2018	1.0959
2018/2019	1.0883
2019/2020*	1.0881

*Assume 2019/2020 FPR for years 2021 and later.

Natural Gas Prices

Retail Natural Gas Prices: Historic 2014 EIA New Jersey retail natural gas prices were escalated using an annual growth rate derived from the Mid-Atlantic Region EIA Annual Energy Outlook 2015 natural gas price forecasts. On average, the annual growth rate was about 3.2%. Retail natural gas prices reported to EIA include the Societal Benefits Charge (SBC)[178], but not the 7% Sales and Use Tax, which CEEEP added.

[178] The Societal Benefits Charge for natural gas customers of 4.1% for residential and 5.0% for C&I is included in the retail prices.

Wholesale (Henry Hub) Natural Gas Prices: Wholesale natural gas prices are taken from the EIA Annual Energy Outlook 2015. The winter and summer prices were derived from the 1994 to 2014 historic average ratio of summer and winter prices to Henry Hub. The summer average ratio was 96.9% and the winter average ratio was 103.1%. With the continued development of shale natural gas in Pennsylvania, using a Mid-Atlantic regional wholesale hub for natural gas may be appropriate going forward. CEEEP is tracking this issue.

Table B-4: Retail and Wholesale Natural Gas Prices (Nominal $/MMBtu)

	Retail Prices			*Henry Hub Wholesale Prices*		
	Residential	*Commercial*	*Industrial*	*Average Price*	*Summer*	*Winter*
2014	$11.14	$10.25	$10.68	$4.44	$4.30	$4.58
2015	$10.71	$9.86	$8.10	$3.82	$3.70	$3.94
2016	$11.18	$10.56	$9.35	$3.90	$3.78	$4.02
2017	$12.18	$11.50	$11.62	$4.09	$3.96	$4.21
2018	$13.05	$12.22	$13.73	$4.61	$4.46	$4.75
2019	$14.27	$13.60	$15.83	$5.07	$4.92	$5.23
2020	$15.25	$14.69	$17.45	$5.54	$5.36	$5.71
2021	$16.16	$15.68	$18.93	$5.79	$5.61	$5.97
2022	$16.90	$16.47	$20.08	$5.97	$5.78	$6.15
2023	$17.57	$17.18	$21.14	$6.25	$6.06	$6.45
2024	$18.20	$17.85	$22.19	$6.48	$6.28	$6.68
2025	$18.83	$18.51	$23.19	$6.72	$6.51	$6.93
2026	$19.18	$18.79	$23.48	$7.09	$6.87	$7.31
2027	$19.22	$18.69	$23.20	$7.21	$6.99	$7.43
2028	$19.26	$18.55	$22.80	$7.34	$7.11	$7.57
2029	$19.39	$18.53	$22.62	$7.52	$7.29	$7.75
2030	$19.57	$18.56	$22.48	$7.63	$7.39	$7.86
2031	$20.03	$18.92	$22.94	$8.07	$7.82	$8.32
2032	$20.59	$19.42	$23.61	$8.48	$8.21	$8.74
2033	$21.23	$20.00	$24.41	$8.89	$8.61	$9.16
2034	$21.85	$20.55	$25.19	$9.31	$9.02	$9.60
2035	$22.66	$21.33	$26.34	$9.70	$9.40	$10.00
2036	$23.39	$21.99	$27.24	$10.12	$9.80	$10.43
2037	$24.49	$23.11	$28.93	$10.44	$10.12	$10.76

PROPANE AND HEATING OIL PRICES

Propane Prices: Historic 2014 EIA New Jersey residential and wholesale/resale propane prices were escalated using an annual growth rate derived from the Mid-Atlantic Region EIA Annual Energy Outlook 2015 propane price forecasts (Residential Prices and Prices for All Users, respectively). Propane prices were initially presented as weekly averages from January to March and October to December and were averaged to develop an annual price. On average, the annual growth rate was about 1.9% for the residential prices and 2.2% for the prices for all users. In addition, CEEEP added the 7% Sales and Use Tax.

Heating Oil Prices: Historic 2014 EIA New Jersey residential and wholesale/resale heating oil prices were escalated using an annual growth rate derived from the Mid-Atlantic Region EIA Annual Energy Outlook 2015 heating oil price forecasts (Residential Prices and Prices for All Users, respectively). Heating oil prices were initially presented as weekly averages from January to March and October to December and were averaged to develop an annual price. On average, the annual growth rate was about 3.6% for the residential prices and 4.9% for the prices for all users. In addition, CEEEP added the 7% Sales and Use Tax.

Table B-5: Residential and Wholesale Propane and Heating Oil Prices (Nominal $/Gallon)

	Propane		*Heating Oil*	
	Residential	*Wholesale/Resale*	*Residential*	*Wholesale/Resale*
2014	$4.16	$1.54	$4.12	$2.99
2015	$3.55	$0.85	$3.00	$1.76
2016	$3.62	$0.86	$3.09	$1.82
2017	$3.79	$0.92	$3.19	$1.89
2018	$3.93	$0.96	$3.28	$1.98
2019	$4.07	$1.00	$3.38	$2.05
2020	$4.21	$1.04	$3.49	$2.14
2021	$4.33	$1.08	$3.60	$2.23
2022	$4.47	$1.12	$3.72	$2.33
2023	$4.60	$1.17	$3.85	$2.43
2024	$4.73	$1.21	$3.97	$2.53
2025	$4.86	$1.25	$4.11	$2.64
2026	$5.00	$1.30	$4.25	$2.75
2027	$5.13	$1.34	$4.39	$2.87
2028	$5.26	$1.39	$4.53	$3.00
2029	$5.39	$1.43	$4.68	$3.12
2030	$5.53	$1.48	$4.83	$3.26
2031	$5.67	$1.53	$4.99	$3.35
2032	$5.81	$1.57	$5.15	$3.51
2033	$5.96	$1.62	$5.32	$3.66
2034	$6.12	$1.68	$5.50	$3.80
2035	$6.28	$1.74	$5.69	$3.99
2036	$6.46	$1.81	$5.89	$4.16
2037	$6.64	$1.88	$6.11	$4.34

ENVIRONMENTAL EXTERNALITIES

Environmental Externality Benefits: Avoided emission savings are calculated by multiplying the emission damages by the energy savings. CEEEP is currently researching reputable sources for determining a value for avoided mercury emissions.

Forecasted Carbon Dioxide (CO2) Social Cost: Values for the Social Cost of Carbon were taken from the U.S. Government Interagency Working Group on Social Cost of Carbon[179]. Values were

[179] EPA Fact Sheet, "Social Cost of Carbon", December 2015
http://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

reported in 2007$/metric ton, and were converted to nominal dollars using the EIA projected U.S. GDP Price Index[180]. The study presented three values for the social cost of carbon, using a discount rate of 2.5%, 3%, and 5%. The scenario using a discount rate of 3% is presented in Table B-6.

Table B-6: Social Cost of Carbon (Nominal $/metric ton) and U.S. GDP Chain-type Price Index

	Social Cost of CO_2	GDP Chain-type Price Index
2014	$38.84	1.19
2015	$37.70	1.21
2016	$38.90	1.23
2017	$40.20	1.25
2018	$41.49	1.27
2019	$42.75	1.29
2020	$44.07	1.31
2021	$44.97	1.33
2022	$45.91	1.35
2023	$46.82	1.38
2024	$47.70	1.40
2025	$48.53	1.43
2026	$49.38	1.45
2027	$50.23	1.48
2028	$51.09	1.51
2029	$51.95	1.54
2030	$52.82	1.56
2031	$53.89	1.59
2032	$54.95	1.62
2033	$55.99	1.65
2034	$57.02	1.68
2035	$58.05	1.71
2036	$59.09	1.74
2037	$60.14	1.78

Historical Emissions Damage Estimates: Damage estimates for sulfur dioxide (SO2), nitrogen oxide (NOx), and particulate matter (PM) in Table B-7 were taken from the National Research Council's 2010 study - Hidden Costs of Energy.[181] All values are in $/short ton. Note that for emissions that are part of a cap-and-trade program, their allowance or permit price is incorporated into the price of energy. If the emission cap is binding, then a reduction in electricity usage will not lower total emissions but will free up an allowance that then can then be used resulting in no net change in emissions.

[180] EIA Annual Energy Outlook 2015. 2005=1.0
[181] National Research Council. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. Washington DC: The National Academies Press, 2010. http://www.aaec.arkansas.gov/Solutions/Documents/Hidden%20Costs%20of%20Energy%20Unpriced%20Consequences%20of%20Energy%20Production%20and%20Use.pdf

Table B-7: Mean Damages per Short Ton of Criteria-Pollutant-Forming Emissions (2007 $/short ton)

From Coal-fired Power Plants	*Unit*	*2007 $*
SO2	***$/Short Ton***	***5,800***
NOx	***$/Short Ton***	***1,600***
PM2.5	***$/Short Ton***	***9,500***
PM10	***$/Short Ton***	***460***
From Gas-fired Power Plants	*Unit*	*2007 $*
SO2	***$/Short Ton***	***13,000***
NOx	***$/Short Ton***	***2,200***
PM2.5	***$/Short Ton***	***32,000***
PM10	***$/Short Ton***	***1,700***

PJM Marginal Units: Table B-8 shows the type of fuel used by marginal resources in the PJM Real-Time Energy Market[182] in 2014. Please note that the category "Other" includes Uranium and emergency DR.

Table B-8: 2015 (Jan-Sep) PJM Marginal Units

Fuel Type	*% on the Margin*
Coal	***54.46%***
Gas	***34.88%***
Oil	***7.39%***
Wind	***2.74%***
Other	***0.46%***
Municipal Waste	***0.06%***

Power Plant Emission Rates: Power plant emission rates for CO_2, NO_x, and SO_x are shown in Table B-8. Emission rates are in pounds per MWh. CEEEP is currently researching externality values for mercury. The NJ DEP estimated in October 2014 that the emission rate for mercury is 2.11 mg/MWh for electricity. Note that energy efficiency displaces some renewables given that the Renewable Portfolio Standard (RPS) is a percentage of electricity retail sales. This displacement should be accounted for when calculating emission reductions due to energy efficiency.

Table B-9: Power Plant Emission Rates (lbs/MWh)

	CO_2	*NO_x*	*SO_x*
Coal[183]	***2,249***	***6***	***13***
Natural Gas[184]	***1,135***	***1.7***	***0.1***
Oil[185]	***1,672***	***4***	***12***
Wind	***0***	***0***	***0***
Other	***0***	***0***	***0***

[182] PJM State of the Market – 2015, Section 3 – Energy Market, pg. 79. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml

[183] U.S. EPA, eGRID 2000.

[184] Ibid.

[185] Ibid.

Municipal Waste[186]	***2,988***	***5.4***	***0.8***

OTHER ASSUMPTIONS

Discount Rate: Discount rates are used to convert future economic values into present day dollars. A nominal discount rate of 7% is used[187]. The utility WACC should be used for utility specific cost-benefit analyses of energy efficiency programs.

Avoided Electric and Natural Gas Losses: Avoided average electric transmission and distribution losses are assumed to be 6.2%.[188] Marginal losses are assumed to be approximately 1.5 times average losses. PJM wholesale energy prices include marginal transmission losses. It is unknown what part of the T&D losses are transmission related and what are distribution related. To account for marginal distribution losses, assume that average distribution losses are 5%. During the peak hour, marginal losses are at their highest and may be 2.7 times average losses. Electric utilities report losses on their respective webpages.[189] In calculating peak reductions due to energy efficiency measures, realized demand savings must be appropriately calculated.[190]

Avoided natural gas losses are assumed to be 1%[191] based on the 2014 New Jersey Protocols.

Avoided Electric and Natural Gas Transmission and Distribution (T&D): EnerNOC has recommended that CEEEP use an Avoided Electric T&D cost of $30/kW-yr. Tables B-10 to B-12 provide estimates from the Avoided Energy Supply Costs in New England 2015 Report, Maryland Avoided Costs 2014 Study, and EnerNOC respectively.

Table B-10: New England Avoided T&D Cost Estimates (2015$/kW-yr)192

Company	State	Transmission	Distribution	Total
NStar		$14.41	$85.28	$99.69
CL&P	CT	$1.25	$29.74	$30.99
WMECo	ME	$20.30	$60.87	$81.17
National Grid MA	MA	$19.95	$109.25	$129.20
National Grid RI	RI	$19.95	$87.13	$107.08
UI		$2.54	$45.96	$48.50

[186] U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
[187] This is approximately the average of the prevailing cost of capital for utilities in NJ as compiled by CEEEP from publicly available documents. Note U.S. Federal Government uses 7 percent. See Circular No. A-94 Revised https://www.whitehouse.gov/omb/circulars_a094/
[188] 10 year (2005-2014) Average: "New Jersey Supply and Disposition of Electricity" http://www.eia.gov/electricity/state/newjersey and http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3
[189] PSEG: https://www.pseg.com/business/energy_choice/third_party/rate_class.jsp
Orange Rockland: https://www.oru.com/documents/tariffsandregulatorydocuments/ny/electrictariff/electricGI31.pdf
Atlantic City: http://www.pepcoholdings.com/about-us/do-business-with-phi/energy-suppliers/retail-energy-suppliers/new-jersey/registered-suppliers/settlement-informaton/class-load-profile-information/
JCP&L: https://www.firstenergycorp.com/content/dam/supplierservices/files/interval-data/JC%20Loss%20Factors.pdf
[190] NREL, Chapter 10: Peak Demand and Time-Differentiated Energy Savings Cross-Cutting Protocols, The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures, April 2013.
[191] "New Jersey Clean Energy Program Protocols to Measure Resource Savings", updated March 17, 2014. http://njcleanenergy.com/files/file/Appeals/NJ%20Protocols%20Revisions%202013%20Update_04-16-2014_clean.pdf
[192] Avoided Energy Supply Costs in New England: 2015 Report. Prepared for Avoided Energy Supply Component Study Group by Synapse Energy Economics, Inc. http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report.pdf

Table B-11: Maryland Avoided T&D Cost Estimates (2012$/kW-yr)[193]

Company	State	Total
BGE	MD	$34.13
Potomac Edison	MD	$25.00
Pepco/SMECO	MD	$25.00
DPL	MD	$25.00

Table B-12: Various Avoided T&D Cost Estimates ($/kW-yr)[194]

State - Area	Cost
CT-CL&P	$29.20
WI - Statewide	$30.00
NY - Upstate	$33.50
CA - SCE	$54.60
CA - SDG&E	$74.80
CA - PG&E	$76.60
NY - Con Edison	$100.00

CEEEP is currently researching reputable sources for avoided natural gas T&D costs.

Renewable Energy Credits and Solar Renewable Energy Credits: The New Jersey Renewable Portfolio Standard (RPS) is based upon a percentage of retail electricity sales. CEEEP has projected the additional cost that SRECs and RECs add to the wholesale cost of energy based upon current REC and SREC prices, projections of the levelized cost of electricity, and the wholesale energy and capacity revenue that wind and solar earn.[195] These projections are provided in Table B-13.

[193] Avoided Energy Costs in Maryland: Assessment of the Costs Avoided through Energy Efficiency and Conservation Measures in Maryland April 2014. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwj_m_T7qafLAhXKej4KHRknBRcQFggcMAA&url=http%3A%2F%2Fwebapp.psc.state.md.us%2FIntranet%2Fcasenum%2FNewIndex3_VOpenFile.cfm%3Ffilepath%3DC%3A%255CCasenum%255C9100-9199%255C9154%255CItem_525%255C%255CAvoidedEnergyCostsinMaryland.pdf&usg=AFQjCNGqBFS45mr8ClHV2pZ3oL5Mfy-qrw&bvm=bv.115339255,d.cWw

[194]

PA: Potential study, Appendix 1: http://www.puc.state.pa.us/electric/pdf/Act129/Act129-PA_Market_Potential_Study_App1.pdf

WI: Page EE-13 of study: http://psc.wi.gov/reports/documents/wipotentialfinal.pdf

CA: Page 37 of Word Doc at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128594.htm#P84_2869
NY: Appendix 2, Table 2 at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B329FD000-D108-47AC-ADAF-9E37730B68CA%7D
CT: "Assessment of Avoided Cost of Transmission and Distribution" Prepared for: Connecticut Light and Power Company by: ICF International, October 30, 2009. www.dpuc.state.ct.us

[195] http://markets.flettexchange.com/new-jersey-srec/, https://www.eia.gov/forecasts/aeo/electricity_generation.cfm

Table B-13: Renewable Energy Adder ($/MWh)

Year	Renewable Adder
2015	$5.78
2016	$7.49
2017	$9.26
2018	$11.72
2019	$14.56
2020	$7.77
2021	$9.04
2022	$7.85
2023	$7.38
2024	$7.00
2025	$6.79
2026	$6.34
2027	$6.18
2028	$5.96
2029	$5.56
2030	$5.43
2031	$5.23
2032	$4.98
2033	$4.63
2034	$4.14
2035	$3.76
2035	$3.38
2035	$2.95
2035	$2.46

Administrative Costs: The administrative costs considered as part of the Energy Efficiency program include program administration, program development, marketing and sales costs, training, rebates and direct incentives, rebate processing, inspections, evaluation and quality control. Administrative costs should be included at the appropriate level of analysis based upon the type of administrative costs. For instance, costs associated with marketing a particular program should be included in that program's CBA but not assigned to the CBA at the measure level. Administrative costs that are for a portfolio should be included in the portfolio CBA. Administrative costs should also include those of relevant BPU Staff