BP1 Final Report

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Preface

Dresser, Inc., Dresser Waukesha was acquired by GE Energy on February 1, 2011. The Waukesha division has been combined with GE Jenbacher to form GE Energy Gas Engines. This acquisition has resulted in a reevaluation of our current product development programs including the DE-EE0004016 cooperative agreement.

Product rationalization decisions related to the GE Energy Gas Engines acquisition require a change to the program that would introduce significant technical risks to successful completion of DE-EE0004016 that were not present when the program was started in October 2010. The program would require a change in engine platforms. This change would result in performing basic combustion work to develop a combustion system compatible with our proposed strategy. Since this cooperative agreement is intended to have a minimal research component and is to result in a fully commercialized product by September 2013, GE Energy Gas Engines would be performing activities outside the guidelines of this cooperative agreement.

This final report is based on activities executed during Budget Period 1 prior to the program being terminated.

Project Objective

Dresser, Inc. (GE Energy, Waukesha gas engines) will develop, test, demonstrate, and commercialize a 1.1 Megawatt (MW) natural gas fueled combined heat and power reciprocating engine powered package. This package will feature a total efficiency > 75% and ultra low CARB permitting emissions. Our modular design will cover the 1 – 6 MW size range, and this scalable technology can be used in both smaller and larger engine powered CHP packages. To further advance one of the key advantages of reciprocating engines, the engine, generator and CHP package will be optimized for low initial and operating costs. Dresser, Inc. will leverage the knowledge gained in the DOE - ARES program. Dresser, Inc. will work with commercial, regulatory, and government entities to help break down barriers to wider deployment of CHP. The outcome of this project will be a commercially successful 1.1 MW CHP package with high electrical and total efficiency that will significantly reduce emissions compared to the current central power plant paradigm.

Principal objectives by phases for Budget Period 1 include:

- Phase 1 – market study to determine optimum system performance, target first cost, lifecycle cost, and creation of a detailed product specification.
- Phase 2 – Refinement of the Waukesha CHP system design concepts, identification of critical characteristics, initial evaluation of technical solutions, and risk mitigation plans.

Background

The initial goal of this program is to develop, demonstrate and commercialize a 1.1MW CHP system consisting of a natural gas reciprocating engine utilizing ultra-low CARB permitting engine technology with three-way catalyst aftertreatment. The standardized package will also utilize 'waste' heat to maximize the total electrical and thermal efficiency. Achieving the emissions target with the desired reliability will require the development and commercialization of new technology. Technology developed during the DOE-ARES program will also be incorporated into this package.

Accomplishments

During this budget period, the following tasks have been accomplished:

- Market study activities were completed.
- Project plans analyzed and updated.
- Initial system technology investigations and concept designs were conducted.
- A key component was redesigned from rough prototype to production intent. Quotes for prototype and production pricing were received from suppliers.
- Continuous improvement activities related to power cylinder and fuel system were completed.

Progress and Status

Market Study – The marketing study was completed in June. A final report and list of recommendations from the market study was presented to Waukesha senior management. A final presentation was presented via Webex to DOE personnel. The marketing study final report is attached as an appendix to this report.

Commercial Requirements – Preliminary commercial requirements were started and awaiting the market study information for additional refinement.

Initial Technical and System Evaluation – The technical team was continuing to evaluate existing technologies to determine opportunities to improve upon our initial technology path to achieve ultra low emissions and a high efficiency product. Quotes for prototype and production quantities have been received from numerous suppliers. Redesign of one of the key components from rough prototype to production intent was completed. This early redesign activity was necessary to meet the program's future deliverables and to mitigate program technical risk.

Technical Requirements – Preliminary technical requirements related to the engine and the CHP system have been created. Additional modifications were expected based on changes to the commercial requirements.

Program Resources – Key positions of the project team were filled to support the design and development aspect of this program. Additional design personnel were identified to support the program and were to join the program in BP2. External contract support was evaluated in support of this program.

Continuous Improvement Activities – Opportunities were identified to improve engine reliability, to reduce life cycle cost and to improve efficiency were pursued related to the power cylinder and the fuel system. These activities supported the overall commercial viability of this future product.

Task 3: Concept Definition

Subtask 3.1 Concept Definition

Design concepts were developed for the engine and CHP sub-systems using input from the initial commercial requirements, previous ARES engine experience, and supplier input. Preliminary

simulation data suggested that the total efficiency of this concept is higher than our existing APG1000 CHP product, while maintaining similar electrical efficiency, and having significantly lower emissions. The design also featured enhanced flexibility for providing either steam or hot water depending on the customer's needs.

Subtask 3.2 Preliminary System Layout

Preliminary heat exchanger sizing was completed for each of the engine's thermal circuits. For the lube oil and engine coolant circuits a gasketed plate and frame style heat exchanger was chosen to greatly minimize the risk of contamination of the customer's circuit. Consideration was given to two-stage cooling when practical to maximize the amount of useful heat available to the customer. The system layout was then analyzed in several different configurations. The objective was to standardize the layout and performance as much as possible on the engine side and provide maximum thermal flexibility on the customer side. This was accomplished by arranging the heat exchangers and engine side piping in a fixed way. The customer side piping could be combined into different configurations using pipe "jumpers" that enable maximum thermal flexibility. This new heat exchanger layout offered improved flexibility compared to the existing APG1000 CHP package.

Subtask 3.3 Technical and Market Requirements Updated

The Engine and CHP Package Technical Requirements were updated based on the evaluation of design concepts explored. These requirements were to guide any investigative technical activities to ensure the engine and CHP package were capable of meeting the market requirements. The Market Requirements were to be updated based on analysis of the market study data collected.

Task 4: Concept Development

Subtask 4.1 Final Technical and Market Requirements

Due to the agreed cancellation of this program, final technical and market requirements were not completed.

Subtask 4.2 Computer Modeling

The performance of the mixer component has been shown from earlier testing to be a key component for successful operation. A Computational Fluid Dynamics (CFD) simulation of the mixer was undertaken. CFD simulation confirmed our new design concept to be capable of significantly better performance than our original design. A redesign of the mixer to a production intent state was undertaken. The mixer was subdivided into subsystems and cost estimates were made for each of the subsystems. A cost optimized design was developed that was comparable in cost to the production APG1000 mixer but incorporated the new functionality needed for this engine. All the drawings necessary to procure a prototype mixer were completed. Although the DOE cooperative agreement ended August 31, Waukesha gas engines will continue to procure and test this mixer.

Subtask 4.3 Electronic Controls Prototype Testing

Conventional catalyst control relies on “switching type” automotive oxygen sensors. Experience with controls that use this type of sensor suggest that, while emissions compliance is possible for periods from a few hours to possibly a week, longer term compliance is difficult to maintain. Two alternative control schemes were tested by Waukesha. Both alternative control schemes have been shown to maintain compliance for longer periods of time than conventional catalyst controls. Figure 1 shows NOx emissions compliance over a 23 day period of continuous operation for alternative control #1. Figure 2 shows CO emissions compliance over a 23 day period of continuous operation for alternative control #1. Following a setpoint change at approximately 3650 engine hours no further changes were made to the control for the duration of the test.

Figure 1 NOx Emissions Versus Time for Alternative Control #1

Figure 2 CO Emissions versus Time for Alternative Control #1

Figure 3 shows a cumulative frequency distribution of NOx and CO emissions operated over a range of ambient conditions for alternative control #2. The automated extended lab test represents engine operation at different loads, ambient humidity, ambient temperature, and fuel quality and was taken over a 2 week period with about 280 hours of actual run time. Data from an automated extended lab test show that the control has the capability to maintain the engine in control 99.5% of the time with a 90% confidence level.

Figure 3 Cumulative Frequency of NO and CO Emissions for Alternative Control #2

Subtask 4.4 Engine Package Prototype Development Testing

A package consisting of an engine, a generator, system controls and an aftertreatment system was built and tested in Waukesha's Engineering test lab. This test unit allowed for rapid testing of the new or modified sub-systems in a controlled environment to verify that the functionality will meet the Technical Requirements and to validate the computer simulations conducted. This testing was a critical step in mitigating any risks that remain at this phase of the program. The engine accumulated over 3600 hours of operation. During most of those test hours the engine was stopped and restarted every morning during the work week to simulate the stop-start cycle that is common for CHP applications. Several minor issues were found as a result of this testing; however, the engine ran with no major issues.

Subtask 4.5 Subsystem Improvements

A number of subsystems were modified to improve engine reliability: A new multi-layer steel head gasket was developed that provided higher peak cylinder pressure sealing capability and more consistent sealing than the production APG1000 head gasket. Extensive rig testing, both hot and cold, was performed to qualify the new design. Figure 4 shows cylinder heads mounted to the testing rig and operating in the cold portion of the test.

Figure 4 Cylinder Head Gasket Undergoing Rig Testing (Cold portion of the test shown)

Valve rotators were applied to the cylinder head to increase exhaust valve life and reduce variability of exhaust valve life. Valve rotators provide an intermittent slight rotation of the valve as the valve is being opened. The slight rotation can give more uniform wear of the valve and reduce carbon buildup, preventing failure due to burning of the valve seating area.

A new breather design does a better job of filtering oil from the blow-by gasses and regulating crankcase pressure. This new breather design prevents fouling of the turbocharger compressor since the blow-by gasses are now redirected into the compressor inlet due to emission regulations.

New designs to resolve an oil leak on the top of cylinder head and a coolant leak on the intercooler were implemented.

By increasing spark plug life the CHP package life cycle cost can be reduced. Ten new spark plug concepts were tested in the lab for performance. Criteria such as spark plug demand voltage, seat temperature, engine lean limit, Coefficient of Variation (COV) of Indicated Mean Effective Pressure (IMEP), burn duration, and knock margin were measured to quantify spark plug performance. Figure 5 shows a picture of the baseline production Waukesha spark plug, P/N 69919D. Confidentiality agreements prevent showing the test spark plugs. Two spark plugs had sufficient performance to warrant taking to field test.

Figure 5 Waukesha Spark Plug P/N 69919D

Patents

No patents have been requested or issued at this stage of the program.

Publications / Presentations

No publications or presentations were created during this budget period.

Activities during GFY 4th Qtr 2011

During the July – September 2011 quarter, Dresser, Inc. executed the following project activities:

- Presented results of the Market Study to DOE.
- Completed project closure activities per DOE instructions.
- Closed down the project.

Commercialization Status

Due to the change in scope and the requested termination of this program, commercialization of this product will no longer be pursued.

Task / Milestone Schedule

Task/ Milestone Number	Title or Brief Description	Task/Milestone Completion Date				Progress Notes
		Original Planned	Revised Planned	Actual	Percent Complete	
1	Market Opportunity Defined	2/2011	4/2011	6/29/11	100%	Market Study Completed
2	Prelim. Technical System Evaluations Complete	2/2011	3/2011	4/2011	100%	Still need to incorporate Market Study findings
	Gate Review - Management Approval to Proceed into Ph 2	3/2011				Internal phase exit not being pursued due to program termination
3	Project closure	9/2011		10/2011		Revised SOPO and Financials provided to DOE

Project Spend Plan (Final)

Quarter	From	To	Estimated Federal Share of Outlays*	Actual Federal Share of Outlays
	Start	9/30/2010		
4Q10	10/1/2010	12/31/2010		\$252,277
1Q11	1/1/2011	3/31/2011		\$407,542
2Q11	4/1/2011	6/30/2011		\$403,050
3Q11	7/1/2011	9/30/2011		\$169,006
4Q11	10/1/2011	12/31/2011	\$52,792	\$0
Totals			\$52,792	\$1,231,875

* Updated Quarterly

Appendix

“Gas Engine Combined Heat and Power: Adapting “Lessons Learned” from European Markets to U.S. CHP Market Growth”, by GE Energy’s Waukesha gas engines

GE Energy's Waukesha gas engines

Gas Engine Combined Heat and Power: Adapting
“Lessons Learned” from European Markets to U.S. CHP
Market Growth

Prepared by: GE Energy Waukesha gas engines
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Table of Contents

Acronyms	v
Executive Summary	1
1. Project Objectives	6
2. Project Approach	6
2.1 United States Market Study	6
2.2 European Market Study	6
3. United States Market Study	8
3.1 Overview of the Most Attractive U.S. CHP Markets	8
3.2 United States CHP Market Size Overview	11
3.2.1 Overview of U.S. CHP Market Penetration	13
3.2.2 Regional and State CHP Installation, Capacity Trends	17
3.2.3 U.S. CHP Forecasts	24
3.3 Key CHP Drivers and Barriers	25
3.3.1 Spark Spreads; Natural Gas Forecasts	26
3.3.2 Emissions Requirements, Permitting	28
3.3.3 Renewable Portfolio Standards	29
3.3.4 Rate Design	32
3.3.5 Interconnection Requirements	37
3.3.6 Federal, State-Specific CHP Policy Drivers	38
3.4 CHP Supply Chain Overview	42
3.5 Emerging U.S. Challenges, Opportunities	43
4. European Market Study	1
4.1 European CHP Policy	1
4.1.1 Overview of European CHP Markets	1
4.1.2 European Policy and Regulatory Landscape	6
4.1.2.1 European Emissions Trading System (EU ETS)	6
4.1.2.2 Air Quality Regulations in Europe	7
4.1.2.3 The EU Cogeneration Directive	8
4.1.2.4 Overview of CHP Support Mechanisms across Europe	9
4.1.3 Germany	12
4.1.3.1 Policies	12
4.1.3.2 Market Effects	14

Table of Contents

4.1.4	Belgium	16
4.1.4.1	Policies	16
4.1.4.2	Market Effects	17
4.1.5	The Netherlands	18
4.1.5.1	Policies	18
4.1.5.2	Market Effects	20
4.1.6	Other European CHP Markets: Portugal, Denmark, and Finland	24
4.1.7	Key Lessons Learned from the European CHP Experiences	27
4.2	Commercial Analysis of European CHP Markets	30
4.2.1	Target Markets in Specific Countries	32
4.2.1.1	Belgium	32
4.2.1.2	Italy	33
4.2.1.3	Germany	34
4.2.1.4	The Netherlands	37
4.2.1.5	Russia	38
4.2.1.6	Poland	39
4.2.1.7	United Kingdom	40
4.2.2	IESG Data Analysis	44
4.2.2.1	Market Share by Engine Size	45
4.2.2.2	Specific Country Sales History by Size	49
4.2.2.3	Distribution of Total EU CHP Sales from, 2005 – 2010	56
4.2.3	Summary of European CHP Market Opportunities	57
5.	Recommendations to the U.S. Department of Energy	59
5.1	Objective and Approach	59
5.2	Overview of DOE’s CHP Efforts to Date	59
5.3	Dresser-Waukesha’s Recommendations to DOE	60

List of Exhibits:

Figure 3-1: CHP Remaining Technical Potential by State (MW)	8
Figure 3-2: CHP Percentage of National Power Production, 2008	13

Table of Contents

Figure 3-3: Cumulative CHP Capacity (GW) Additions, 1995 – 2010	15
Figure 3-4: Percent of U.S. CHP Installed Capacity (GW) by Industry, 1995 – 2010	16
Figure 3-5: Percent of U.S. CHP Installations (# of Sites) by Industry, 1995 – 2010	16
Figure 3-6: Number of U.S. CHP Installations by industry and Size, 1995 – 2010	17
Figure 3-7: Number of Annual CHP Installation Additions by Region, 1995 – 2010	18
Figure 3-8: Annual CHP Capacity (GW) Additions by Region, 1995 – 2010	18
Figure 3-9: Annual CHP Capacity (GW) Additions by Region and Fuel Type, 1995-2010	19
Figure 3-10: Percentage of U.S. Sites with Reciprocating Engine Installations by Industry	21
Figure 3-11: Percentage of Capacity of Reciprocating Engine Installations by Industry	22
Figure 3-12: CHP Capacity (MW) Targets through 2030	24
Figure 3-13: CHP Remaining Technical Potential by State (MW)	25
Figure 3-14: U.S. and Canadian Unconventional Gas Production (Average Annual Bcfd)	27
Figure 3-15: States with Output-Based Emissions Requirements	29
Figure 3-16: States with Portfolio Requirements that Include CHP	29
Figure 3-17: State Interconnection Standards: Assessment of DG Favorability	37
Figure 3-18: CHP Supply Chain Overview	42
Figure 4-1: European Generation Profile 1972 - 2008	1
Figure 4-2: Share of Cogeneration in Total Electricity Generation in Europe, 2007	3
Figure 4-3: EU Country Percentage CHP Generation, 2000 - 2009	5
Figure 4-4: Growth in Biogas (all plants) CHP Capacity (MW) in Germany	15
Figure 4-5: Growth in CHP capacity in Flanders, 2000 - 2008	18
Figure 4-6: Growth of CHP Capacity in the Netherlands, 1998 – 2006	20
Figure 4-7: Growth of Thermal CHP in the Netherlands, 1982 – 1994	21
Figure 4-8: Growth in Dutch CHP Capacity in the Greenhouse Sector	22
Figure 4-9: Distribution of CHP in the Dutch Commercial Sector, 1998 - 2006	23
Figure 4-10: CHP Capacity in the Netherlands by Technology Type, 1998 – 2006	24
Figure 4-11: Market Potential (Percent of Generation) for CHP in 2015 and 2030	30
Figure 4-12: Forecasted CHP Capacity by EU Country, 2020	31
Figure 4-13: Growth in German Biogas Capacity, 2000 - 2007	36
Figure 4-14: CHP Installed Capacity by Sector in the Netherlands	37
Figure 4-15: Growth in UK CHP Capacity and Installations, 1996 - 2009	40
Figure 4-16: UK CHP Electrical Capacity by Sector in 2009	42

Table of Contents

Figure 4-17: CHP Market Share – 1.0 MW - 1.5 MW Systems (Selected Countries)	45
Figure 4-18: CHP Market Share – 1.5 MW - 2.0 MW Systems (Selected Countries)	45
Figure 4-19: CHP Market Share – 2.0 MW - 2.5 MW Systems (Selected Countries)	47
Figure 4-20: CHP Market Share – 2.5 MW - 3.0 MW Systems (Selected Countries)	48
Figure 4-21: 5-Year Sales Totals by Country and Size Class	56
Table 1: State Leaders, CHP-Favorable Markets	2
Table 3-1: State Leaders, CHP-Favorable Markets	9
Table 3-2: ACEEE State CHP-Favorable Market Scoring Overview	10
Table 3-3: Prime Mover (% kW) of CHP by U.S. Census Division, 1995 – 2010	20
Table 3-4: Reciprocating Engine Installations by Region	20
Table 3-5: Top Ten U.S. States by CHP Capacity, 1995 – 2010	23
Table 3-6: Resource Eligibility under Current State RPS Policies	31
Table 3-8: Key Federal CHP Policies	39
Table 4-1: Percentage of CHP in Gross Generation	4
Table 4-2: Emissions Limits for Natural Gas Engines	8
Table 4-3: Overview of European Support Mechanisms for CHP	11
Table 4-4: German Renewable Energy Act Feed-in Tariffs	14
Table 4-5: Growth of Reciprocating Engine CHP in Germany, 2004 - 2006	14
Table 4-6: Number and Capacity of UK CHP Schemes by Sector, 2009	43

Acronyms

ACEEE	American Council for an Energy-Efficient Economy	MACRS	Modified Accelerated Cost Recovery System
APS	Alternative Portfolio Standard	MEP ²	Milieukwaliteit van de Elektriciteitsproductie
ARPA-E	Advanced Research Projects Agency-Energy (U.S.)	MIT	Massachusetts Institute of Technology
B.KWK ¹	Bundesverband Kraft-Wärme-Kopplung	MMBtu	Million British Thermal Units
BAAQMD	Bay Area Air Quality Management District (CA)	MVA	Megavolt Amperes
BACT	Best Available Control Technology	MW	Megawatt
BEMS	Building Energy Management System	MWe	Megawatt (electric capacity)
CAA	U.S. Clean Air Act	MWh	Megawatt Hour
CARB	California Air Resources Board	MWth	MegaWatt (thermal capacity)
CCA	Climate Change Agreement	NAAQS	National Ambient Air Quality Standards
CCGT	Combined Cycle Gas Turbine plant	NAP	National Allocation Plan
CHP	combined heat and power	NECD	National Emissions Ceiling Directive
CO₂	Carbon Dioxide	NOx	Nitrous Oxides
CODE Project	Cogeneration Observatory and Dissemination Europe Project	NSR	New Source Review
CPUC	California Public Utilities Commission	NYSERDA	New York State Energy Research and Development Authority
CRC	Carbon Reduction Commitment	ORNL	Oak Ridge National Lab
DG	Distributed Generation	PM	Particulate Matter
DHC	District Heating and Cooling	RAC	Regional Application Center
DOD	U.S. Department of Defense	RES	Renewable Energy Standard
DOE	U.S. Department of Energy	RGGI	Regional Greenhouse Gas Initiative
DOER	Department of Energy Resources (MA)	ROCs	Renewable Obligation Certificate
ECA	Enhanced Capital Allowance	ROI	Return on Investment
EERS	Energy Efficiency Resource Standards	RPS	Renewable Portfolio Standard
EIA	U.S. Energy Information Administration	SCAQMD	South Coast Air Quality Management District (CA)
EPA	U.S. Environmental Protection Agency	SDE ³	Stimulerend Duurzame Energie
ETS	European Emissions Trading System	SJVAPCD	San Joaquin Valley Air Pollution Control District (CA)
EU	European Union	SO₂	Sulfur Dioxide
GHG	Green House Gas	SOx	Sulfur Oxides
GW	Gigawatt	STAG	steam and gas combined cycle natural gas power plant
IEA	International Energy Agency	TRC	Total Resource Test
IEEE	Institute of Electrical and Electronics Engineers	TWh	Terawatt
IESG	International Engine Statistics Group	VOC	Voice of the Customer
kW	Kilowatt	VOCs	Volatile Organic Compounds
LPG	Liquefied Petroleum Gas	WWTP	Wastewater Treatment Plant
LSE	Load Serving Entity		

¹ B.KWK - German CHP Association

² MEP - a Dutch kWh subsidy paid to domestic producers of electricity from renewable sources and CHP who feed-in to the national grid

³ SDE - a modified (current) Dutch feed-in tariff

Executive Summary

This report presents the key findings of a research effort Dresser-Waukesha conducted to characterize the U.S. and European markets for commercial (1 – 5 MW electrical output) cogeneration, also known as combined heat and power (CHP).¹ As part of its commercialization plan, Dresser-Waukesha conducted a comprehensive assessment of the U.S. and European CHP markets to identify technical, commercial, financial, and regulatory barriers/challenges that have to be met or overcome to achieve successful commercialization.

In addition to this comprehensive market assessment, Dresser-Waukesha has developed a set of recommendations for the U.S. Department of Energy to consider leveraging “lessons learned” from successful European CHP markets, in order to enhance the U.S. CHP market potential.

The following is a summary of key findings in U.S. and European markets and Dresser-Waukesha’s recommendations to DOE to further develop U.S. CHP markets.

U.S. CHP Markets – Key Findings

Combined Heat and Power (CHP) systems currently comprise 9 percent (~85 GW) of total generating capacity in the United States, though the achievable potential generating capacity exceeds 20 percent or ~ 240 GW by 2030, according to the DOE (ORNL 2008). The states with the most favorable CHP policies and largest potential for additional CHP potential going forward are summarized in Table 1.

¹ The terms “cogeneration” and “combined heat and power” (CHP) are often used interchangeably.

Table 1: State Leaders, CHP-Favorable Markets

State	Overall ACEEE Score (2010) ¹	Number of CHP Installations (2005 - 2010)	Total New CHP Capacity (MW)	Average Capacity per Installation (MW)	Technical Potential ²
CA	5	140	120.6	0.9	> 8,000 MW
NY	5	101	102.8	1.0	> 8,000 MW
PA	5	25	80.9	3.2	> 8,000 MW
TX	5	8	380.8	47.6	> 8,000 MW
OH	5	8	94.6	11.8	> 8,000 MW
NC	5	13	17.6	1.4	3,000 - 8,000 MW
IL	5	9	104.8	11.6	3,000 - 8,000 MW
CT	5	62	186.4	3.0	1,000 - 3,000 MW
MA	5	34	41.8	1.2	1,000 - 3,000 MW

¹ The ACEEE score (out of a possible 5) column shows the 9 U.S. markets that rank highest on a combined scoring of six regulatory and policy issues. The full report and methodology can be viewed @ <http://www.aceee.org/sites/default/files/publications/researchreports/e107.pdf>

² The "Technical Potential" column is based on Oak Ridge National Laboratory's (ORNL) 2008 forecast of CHP potential through 2030 by state: http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

Section 3 of this report offers a detailed analysis of U.S. CHP installations (capacity and number of sites) segmented by: region, CHP primary mover, and industry.

Reciprocating engines represent ~2 percent of all CHP installations in the U.S. currently, with the majority of these systems installed in the West and Northeastern U.S.

U.S. federal and state policies establishing tax and mandate incentives, particularly in the past decade, have established CHP as a carve-out of to meet larger energy efficiency and renewable mandates. Rate design, interconnection requirements, and pricing (capital costs of CHP systems, and commodity price considerations) are still major hurdles to spur these markets. Importantly, each state has full jurisdiction over rates and CHP grid interconnection rules, which vary substantially across states. Key CHP barriers in the U.S. include:

- Fuel Availability and Prices – Fuel price volatility creates uncertainty and risk; fuel related costs remain a large part of life cycle/operating costs.

-
- Grid Interconnection and Regulatory Issues – Expensive and time-consuming interconnection processes, high standby rates, and unattractive rates for exported power (net metering) in some jurisdictions.
 - Capital Costs – Fully-installed costs of CHP systems are high in some applications.
 - Permitting – State-by-state regulations impact decisions; CHP not credited for system-wide emissions reductions and benefits of heat recovery.

European CHP Markets – Key Findings

Section 4 of this report provides country-by-country detail regarding CHP policies, applications, and economics. The common characteristics of successful European efforts to promote CHP are as follows:

Government Policy and Support

- **Interconnection Standards** – Grid connection enables CHP plants to sell any surplus electricity to the grid and import when the site need exceeds CHP output. Interconnection standards are intended to provide fair and clear rules for obtaining physical connection to the grid. They outline the procedures for the application process in a transparent way as well as standardize the technical requirements for connection. There are also grid access rights (e.g. Germany), where CHP generators are given priority access to the grid. The three common types of grid access rights are net metering, which allows for the flow of electricity to and from the customer meter, priority dispatch, and licensing exemptions that allow CHP operators to generate without a generator license (e.g. Italy).
- **Target Setting** – Several EU governments realized that CHP was a “no regrets” option for achieving policy goals. In the 1970s, Denmark promoted CHP as a path towards energy security, by implementing energy efficiency measures. Today, many EU countries are using CHP policy to achieve greenhouse emissions reductions. Successful governments set ambitious but achievable targets for the adoption of CHP, establishing policies to meet the targets. CHP has been seen as the best technology in the “medium-term” to support energy efficiency and emissions reductions, while other zero emissions technologies are perfected for the “long-term.”

-
- **Reducing Permitting Barriers** – Some countries have very low barriers for siting generation. For example Finland allows anyone to become a CHP generator through a streamlined permitting process. Free or preferential access to the grid, fast permitting, and easy access to the grid without barriers like high voltage demands, is crucial for the success of CHP.
 - **Outreach and Education** – Some European governments have been proactive in their outreach and education on the benefits of CHP. Germany and the Netherlands have been particularly persistent on outreach. An example is the Netherlands' CHP agency. Lobbying efforts of CHP have been less concentrated and effective, as compared to coal and nuclear advocacy.

Fiscal Support

- **Feed-in Tariffs** – These are the most important policy mechanisms in Europe for incentivizing CHP. These are guaranteed bonus rates for electricity fed into the grid that serve to reduce the CHP investment payback period. According to the economic modeling of the CODE Project, a payback period of three years is required for significant CHP growth.² A critical component to meeting that threshold is a guaranteed tariff term period of 10 to 20 years that allows CHP investors to include that income stream in decision making. Tariffs are typically based on the wholesale price of electricity, plus either a bonus rate in a declining schedule (Germany), based on avoided generation and environmental costs (Portugal), or based on a market-derived tariff (the Netherlands). Rates can differ based on fuel in order to incentivize renewable energy. Germany's biogas tariff is a prime example. Some countries (Denmark, Germany after 2008) provide direct compensation for actual generation from CHP units regardless of how much is fed into the grid.
- **Green Certificate Schemes** – These are market-based mechanisms that also provide an additional income stream to CHP owners. Certificates are provided to CHP operators by the government based on the amount of CO₂ reduced as compared with separate generation of heat and power. Utilities are required to surrender a certain amount of green certificates to the government every year, based on the government's CO₂ reduction goals. This creates a market for utilities to buy the certificates from CHP operators. Biogas provides a significant amount of certificate revenue because it is considered carbon neutral. This is the primary mechanism in Belgium, and has been highly successful where barriers are not a factor (the Belgian Flanders region).

² CODE Project, December 2010. *European Summary Report on CHP Support Schemes*.

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- **Tax Incentives** – Many countries provide tax incentives for capital investment in high efficiency CHP. It is common that governments allow CHP investors to write off 20 – 40 percent of investment costs from their operating profit. Operating costs are lowered for CHP plants in countries that exempt natural gas fuel from fuel taxes and carbon levies. Tax incentives and accelerated depreciation have been employed in the Netherlands, Italy, Belgium, and the United Kingdom.
 - **Upfront Capital Support** – Grants and rebates for purchasing CHP equipment and accelerated depreciation can reduce the payback period to make CHP attractive to investors. The Netherlands, Italy, Spain, and Belgium have a history of providing grants for installed CHP capacity.

Project Objectives

The U.S. Department of Energy sought analysis regarding the success of Europe in promoting CHP adoption and recommendations about how the DOE may adapt or consider those “lessons learned.” Section 3 of this report outlines the myriad policies that have been enacted in European countries that have been successful in this regard. Section 4 includes an overview of U.S. CHP market policies, drivers, barriers, and key market segments. Section 5 includes Dresser-Waukesha’s recommendations to DOE to consider, building upon current efforts to further promote CHP adoption in the U.S.

Project Approach

United States Market Study

The objectives of this section in the report include:

- Leverage secondary data sources to distill key CHP installation trends by geography (state, region); by application (CHP, cogeneration type); by installation size; and by industry segment.
- Identify key U.S. state markets, based on historical CHP installations and a range of policy and regulatory issues.
- Detail the implications of key drivers and barriers – both generally in the U.S., and offering specific, selected state examples.
- Identify the key issues that will affect CHP development in the U.S. going forward.

European Market Study

The objectives of this section in the report include:

- Develop a succinct summary of the CHP markets in key European markets.
- Identify key policy, regulatory issues that have encouraged or hindered the development of CHP in Europe, offering specifics by country and pointing to the core hurdles that need to be overcome to further develop CHP growth.
- Identify the commercial applications of CHP for target European markets.
- Leverage secondary data sources to distill key CHP installation trends by geography (country) and by installation size; and by industry segment.

-
- Develop an overview of the key CHP opportunities, barriers, and drivers by country.

United States Market Study

Overview of the Most Attractive U.S. CHP Markets

When assessing the most attractive CHP markets in the U.S., at a high-level, we examined the markets where the U.S. Department of Energy (DOE) has indicated the greatest remaining growth potential is (as shown in Figure 0-1) and also examined states with the best combination of incentives/favorable CHP regulatory policies (as shown in Table 0-2).

Figure 0-1: CHP Remaining Technical Potential by State (MW)

Source: Technical Potential Source is based on Oak Ridge National Laboratory's (ORNL) 2008 forecast of CHP potential through 2030 by state: http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

It is important to note that there is not currently a U.S.-wide (or regional) analysis publicly available that assesses the technical or economic feasibility of CHP installations or capacity going forward in any level of detail (by geography or CHP installation type). Nor is there a forecast of CHP capacity or installations in the U.S. in any level of segmentation. Therefore, it is important to look at a combination of current trends, regulatory barriers and opportunities, and market dynamics to assess the potential attractiveness of any particular market or region.

Table 0-2 shows the American Council for an Energy-Efficient Economy's (ACEEE's) 2010 assessment and ranking of the most favorable states for CHP development. The table includes nine states which all received a combined ranking of "5" (out of a possible 5) based on a combination of factors the ACEEE considered (methodology described below). The far right column in this table includes the coding for technical CHP potential (leveraging the DOE map in Figure 0-1).

Among these states, five (California, New York, Pennsylvania, Texas, and Ohio) received both the highest ACEEE CHP-favorable ranks, as well as the highest going-forward CHP technical potential remaining, according to the DOE.

Table 0-2: State Leaders, CHP-Favorable Markets

State	Overall ACEEE Score (2010) ¹	Number of CHP Installations (2005 - 2010)	Total New CHP Capacity (MW)	Average Capacity per Installation (MW)	Technical Potential ²
CA	5	140	120.6	0.9	> 8,000 MW
NY	5	101	102.8	1.0	> 8,000 MW
PA	5	25	80.9	3.2	> 8,000 MW
TX	5	8	380.8	47.6	> 8,000 MW
OH	5	8	94.6	11.8	> 8,000 MW
NC	5	13	17.6	1.4	3,000 - 8,000 MW
IL	5	9	104.8	11.6	3,000 - 8,000 MW
CT	5	62	186.4	3.0	1,000 - 3,000 MW
MA	5	34	41.8	1.2	1,000 - 3,000 MW

¹ The ACEEE score (out of a possible 5) column shows the 9 U.S. markets that rank highest on a combined scoring of six regulatory and policy issues. The full report and methodology can be viewed @ <http://www.aceee.org/sites/default/files/publications/researchreports/e107.pdf>

² The "Technical Potential" column is based on Oak Ridge National Laboratory's (ORNL) 2008 forecast of CHP potential through 2030 by state: http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

Even given all of these combined considerations, one manufacturer may view an "attractive" CHP market differently than another manufacturer, based on a range of considerations including but not limited to: current product application and offerings; product and marketing staff available to support a launch or expansion in that market; and the alignment of the underlying industries in a particular state with the manufacturer's business plan, targets, and budget.

ACEEE CHP Market Scorecard Methodology

The first column in Table 0-2 reflects all states (nine) that received a 2010 ACEEE score of “5” (out of a possible 5), reflecting that these have the most attractive CHP markets based on a consideration of several factors. What makes a market “attractive” for CHP depends greatly on a wide range of utility-specific rate and pricing dynamics, the end use segment being targeted, and the trade-offs specific customers are willing to make, and the competitive landscape for cogeneration applications.

In ACEEE’s most recent 2010 rankings, a state could earn up to 5 points for a combination of its position on regulations or policies that encourage CHP development. The six factors ACEEE considered when scoring the overall attractiveness of a state’s CHP market opportunities (in order of importance) include:

- Standard interconnection rules
- Status of CHP-friendly standby rates
- Presence of CHP financial incentives
- Presence of output-based emissions regulations
- Inclusion of CHP/waste heat recovery in a state’s Renewable Portfolio Standard (RPS) requirements or Energy Efficiency Resource Standards (EERS)
- Net metering regulations

ACEEE’s assessment to develop these 2010 scores occurred in June 2010. If a state’s policy was not in place (rather, it was under development), that development was not given credit unless it was a promulgated policy. Similarly, ACEEE did not score states based on prior policies in these six categories which may have been rescinded.

ACEEE’s 2010 report goes into more detail about the data sources and weighting considerations for each of these six factors.³

Table 0-3 shows ACEEE’s assessment in each of the six categories for the five “target markets.”

Table 0-3: ACEEE State CHP-Favorable Market Scoring Overview

³ <http://www.aceee.org/sites/default/files/publications/researchreports/e107.pdf>

State	Interconnection	Standby Rates	Incentives	Output-based Emissions Regulations	CHP included in RPS or EERS	Net Metering	Overall Score
CA							5
NY							5
PA							5
TX							5
OH							5

Source: <http://www.aceee.org/sites/default/files/publications/researchreports/e107.pdf>

Note: the "pies" in the table are filled according to how well ACEEE assesses each state fulfills that policy goal pertaining to CHP development.

United States CHP Market Size Overview

Overview

Combined Heat and Power (CHP) systems currently comprise 9 percent (~85 GW) of total generating capacity in the United States, though the achievable potential generating capacity exceeds 20 percent, or ~240 GW, according to the DOE (ORNL 2008). Fundamentally, CHP applications are based on standard design practices and on proven applications, though there are technology developments that have improved applications and efficiencies.

As

Figure 0-2 reflects, among selected countries, that the U.S. ranks 13th in terms of the percentage of power production that CHP systems represent on the whole. In Section 3.3, the key barriers that account for this CHP market snapshot in the U.S. are explored in more detail.

Figure 0-2: CHP Percentage of National Power Production, 2008

Source: Oak Ridge National Laboratories (ORNL), Dec 2008

http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

Overview of U.S. CHP Market Penetration

Roughly 35 GW of new CHP capacity has been installed in the U.S. since 1995, with just over 4 GW of capacity retired.

Figure 0-3 shows the total CHP installed capacity, segmented by fuel type. Unsurprisingly, natural gas represents ~85 percent of the primary fuel across U.S. CHP applications. The trend shows relatively stable annual additional CHP site installations since 2003, primarily driven by the portfolio laws that many states have which require load serving entities to include a portion of biomass or CHP in their annual generation portfolio.

Figure 0-3: Cumulative CHP Capacity (GW) Additions, 1995 – 2010

Source: EEA U.S. CHP Installation Database (note – 2010 is current through June 2010)

There are two primary ways to reflect the CHP database installation trends: by capacity of CHP installations vs. by the number sites with CHP installations. Both are reflected in the charts that follow, and indicate that while the number of sites installing CHP has remained relatively stable year-over-year (with regional differences), the average size of CHP applications (in MW) has decreased substantially. Figure 0-4 shows the percentage of capacity of CHP installations from 1995 – 2010 by industry, with the largest segment being the chemical industry (29 percent).

Figure 0-4: Percent of U.S. CHP Installed Capacity (GW) by Industry, 1995 – 2010

Source: EEA U.S. CHP Installation Database

Figure 0-5: Percent of U.S. CHP Installations (# of Sites) by Industry, 1995 – 2010

Source: EEA U.S. CHP Installation Database

Figure 0-6 shows another slice of this U.S. CHP data base, reflecting the number of CHP installations by industry and installation size.

Figure 0-6: Number of U.S. CHP Installations by industry and Size, 1995 – 2010

Source: EEA U.S. CHP Installation Database

Regional and State CHP Installation, Capacity Trends

The number and capacity (in GW) of new CHP installations by year and by region are reflected in Figure 0-7 and Figure 0-8.

When considering the U.S. CHP installation trends, it is important to look at both the number of new installed systems as well as the capacity of the installed systems. For example, there were a larger number of smaller engines installed from 2005 – 2010, particularly in the Northeast and West, but the overall added capacity of these new annual CHP systems falls below 1 GW per year – representing a decline over prior years. While the number of installations annually from 2005 – 2009 is between 80 and 120 new units per year, the overall capacity trend implies that the installations are smaller CHP units.

Moreover, many U.S. state Renewable Portfolio Standards (RPS) were initially implemented in the early 2000s, particularly those which had a biomass or a CHP-required RPS component.

Figure 0-7: Number of Annual CHP Installation Additions by Region, 1995 – 2010

Source: EEA U.S. CHP Installation Database (note – 2010 is current through June 2010)

Figure 0-8: Annual CHP Capacity (GW) Additions by Region, 1995 – 2010

Source: EEA U.S. CHP Installation Database (note – 2010 is current through June 2010)

As Figure 0-9 indicates, new CHP capacity additions were below 1 GW each year from 2006 through 2010. This was primarily driven by four factors:

- Volatile natural gas prices
- Changes in wholesale power market rules
- Financial uncertainty
- Smaller CHP installations

The largest number of new CHP installations between 1995 and 2010 occurred in Southern states, which represented 59 percent of all new CHP capacity in the U.S. during this time period. Over 50 percent of the new CHP installations in the Southern region were fueled by natural gas.

Figure 0-9: Annual CHP Capacity (GW) Additions by Region and Fuel Type, 1995-2010

Source: EEA U.S. CHP Installation Database

Table 0-4 reflects that the prime mover in all U.S. regions is either combined cycle or boiler/steam turbine. The trends vary by climate and end user base.

Table 0-4: Prime Mover (% kW) of CHP by U.S. Census Division, 1995 – 2010

Census Division	Prime Mover - % Capacity (kW)								TOTAL
	Boiler/Steam Turbine	Combined Cycle	Combustion Turbine	Fuel Cell	Microturbine	Other	Reciprocating Engine	Waste Heat Recovery	
West South Central	17%	71%	11%	0%	0%	0%	0%	0%	30%
Pacific	18%	47%	31%	0%	0%	0%	4%	0%	16%
Middle Atlantic	33%	59%	5%	0%	0%	0%	4%	0%	15%
South Atlantic	68%	26%	4%	0%	0%	0%	2%	0%	13%
East North Central	54%	32%	9%	0%	0%	0%	3%	1%	11%
East South Central	46%	43%	11%	0%	0%	1%	0%	0%	5%
New England	41%	43%	14%	0%	0%	0%	2%	0%	5%
Mountain	33%	42%	21%	0%	0%	0%	3%	2%	3%
West North Central	69%	14%	9%	0%	0%	0%	5%	3%	2%
TOTAL	35%	50%	13%	0%	0%	0%	2%	0%	100%

Source: EEA U.S. CHP Installation Database

Table 0-5 reflects a summary of the installations and capacity of only reciprocating engines to date only, which are of primary interest to Dresser-Waukesha.

Table 0-5: Reciprocating Engine Installations by Region

U.S. Region	Number of Sites with Reciprocating Engines Installed	Capacity (MW)
South	94	262
West	748	632
Midwest	215	360
Northeast	700	530
Total Installed Recip Engines	1,757	1,784

Source: EEA U.S. CHP Installation Database

The following two pie charts show the percentage of currently installed reciprocating engines by industry segment. Figure 0-10 shows the percent of sites that have installed reciprocating engines, reflecting that schools (11 percent of all reciprocating engine site installations) and multi-family buildings (9 percent) were the largest segments, followed by nursing homes and agriculture, representing 7 percent of all U.S. reciprocating engine site installations.

Figure 0-11 shows a similar industry pie, but instead shows the percentage of reciprocating engine capacity (MW) installed by sector. This view shows that waste water treatment plants (11 percent of all reciprocating engine capacity), colleges and universities (10 percent), food processing (10 percent) and hospitals/healthcare facilities (9 percent) were the largest segments with regard to capacity of reciprocating engines.

Figure 0-10: Percentage of U.S. Sites with Reciprocating Engine Installations by Industry

Source: EEA U.S. CHP Installation Database

Figure 0-11: Percentage of Capacity of Reciprocating Engine Installations by Industry

Source: EEA U.S. CHP Installation Database

Table 0-6 summarizes the top ten U.S. states by CHP installed capacity (cumulative to date). As the data reflects, there is a great deal of variation in the number (and size) of installations by state among the top 10 overall markets, underscoring the importance of looking at data by size, capacity, and number of installations to have a full picture of CHP trends.

Note that Table 0-6 ranks CHP installations based on historical capacity and number of sites by states; whereas the ACEEE state CHP rankings (summarized in Table 0-2above) shows the most attractive states for CHP installations based on a combined scoring of incentives, regulatory issues, and size and number of installations.

Table 0-6: Top Ten U.S. States by CHP Capacity, 1995 – 2010

Rank	State	Region	Capacity (MW)	% US CHP Capacity	Site Count	% US CHP Installations
1	TX	South	16,672	20%	125	4%
2	CA	West	8,590	10%	961	27%
3	LA	South	6,770	8%	63	2%
4	NY	Northeast	5,882	7%	436	12%
5	FL	South	3,490	4%	71	2%
6	PA	Northeast	3,301	4%	124	4%
7	AL	South	3,160	4%	37	1%
8	MI	Midwest	3,101	4%	89	3%
9	NJ	Northeast	2,969	4%	210	6%
10	OR	West	2,544	3%	60	2%
41	KS	Midwest	134	0%	17	0%
42	KY	South	122	0%	7	0%
43	MT	West	113	0%	19	1%
44	RI	Northeast	104	0%	24	1%
45	NE	Midwest	104	0%	16	0%
46	NH	Northeast	98	0%	22	1%
47	ND	Midwest	68	0%	11	0%
48	VT	Northeast	43	0%	28	1%
49	SD	Midwest	24	0%	5	0%
50	DC	South	14	0%	2	0%

Source: EEA U.S. CHP Installation Database

U.S. CHP Forecasts

According to the DOE, CHP technical potential could reach 20% of U.S. generating capacity by 2030, an increase from 85 GW currently to ~240 GW over the next twenty years.

Figure 0-12: CHP Capacity (MW) Targets through 2030

Source: Oak Ridge National Laboratories (ORNL), Dec 2008

However, it is important to note that there is not currently a U.S. (or regional) analysis that plots the technical feasibility (economic or otherwise) of CHP installations or capacity going forward in detail as milestones to reach the DOE target (by geography or CHP installation type). Figure 0-13 indicates the states where the DOE estimates the highest remaining technical potential lies for additional CHP market development, installations.

Figure 0-13: CHP Remaining Technical Potential by State (MW)

Source: Technical Potential Source is based on Oak Ridge National Laboratory's (ORNL) 2008 forecast of CHP potential through 2030 by state: http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

Key CHP Drivers and Barriers

Overview

Federal and state policies establishing tax and mandate incentives, particularly in the past decade, have established CHP as a carve-out of to meet larger energy efficiency and renewable mandates. Rate design, interconnection requirements, and pricing (capital costs of CHP systems, and commodity price considerations) are still major hurdles to spur these markets. Importantly, each state has full jurisdiction over rates and CHP grid interconnection rules, which vary substantially across states. Among the key CHP barriers are:

- Fuel Availability and Prices – Fuel price volatility creates uncertainty and risk; fuel related costs remain a large part of life cycle/operating costs.

-
- Grid Interconnection and Regulatory Issues – Expensive and time-consuming interconnection processes, high standby rates, and unattractive rates for exported power (net metering) in some jurisdictions.
 - Capital Costs – Fully-installed costs of CHP systems are high in some applications.
 - Permitting – State-by-state regulations impact decisions; CHP not credited for system-wide emissions reductions and benefits of heat recovery.

The following sections provide analysis of key CHP drives and barriers.

Spark Spreads; Natural Gas Forecasts

A “spark spread” is the relative difference between the price of fuel and the price of power. Spark spreads are highly dependent on the efficiency of conversion. For a CHP system with a natural gas engine as the prime mover, the difference between the price of natural gas and the price of purchased electricity (the spark spread) is factor that facility operators consider when deciding when to install, run, or expand a CHP system. The spark spread can be used to determine when it is economically viable to produce electricity using the CHP system as opposed to buying it off of the grid.

The basic formula for spark spread is:

$$\text{Price of Electricity} - [(\text{Cost of Gas}) * (\text{Heat Rate})] = \$/\text{MWh} - [(\$/\text{MMBtu}) * (\text{MMBtu} / \text{MWh})]$$

If the spark spread is negative, then it is cheaper to buy electricity from the grid. If it is positive, then it is advisable to run the CHP system from a cost perspective.

The U.S. Department of Energy’s Midwest CHP Application Center suggests that a spark spread difference of at least \$12 per MMBTU is considered the threshold for economic viability of CHP systems. However, it is problematic to focus on spark spread calculations as indicators of CHP viability alone:

- Average prices in the spark spread calculation do not reflect customer’s avoided cost of electricity purchases, which depend on the customer’s electric hourly loads and typically complicated rate structures that vary by utility substantially.
- Spark spreads do not reflect contributions of waste heat applications for space heating, water heating, air conditioning, etc. in combined heat and power systems.

As Figure 0-14 reflects, the EIA predicts that the number of lower 48 natural gas wells completed will increase by 2.3 percent per year from 2009 to 2035. As a result, the average wellhead price for natural gas is expected to increase by an average of 2.1 percent per year, to \$6.26 per million Btu in 2035 (2009 dollars). Henry Hub prices increase by 2.3 percent per year, to \$7.07 per million Btu in 2035. Nonetheless, the Henry Hub price and average wellhead prices do not pass \$5.00 per million Btu until 2020 and 2024, respectively.

Domestic dry gas reserves have grown 42 percent in five years primarily due to the emergence of new supplies of natural gas due to shale gas development. This supply can and will likely fundamentally change the long-term gas supply outlook for the U.S.

Figure 0-14: U.S. and Canadian Unconventional Gas Production (Average Annual Bcfd)

Source: ICF, May 2011

Unlike oil, natural gas prices do not return to the high levels recorded before the 2009 recession nor do they need to. Technology improvements have reduced drilling and operating costs particularly in the production of natural gas from shale formations.

Emissions Requirements, Permitting

By increasing the efficiency of energy use, CHP applications as a general rule reduce local air pollutants such as NO_x and SO₂ and global greenhouse gases such as CO₂, for each unit of power produced. For this reason, the EPA has identified CHP technologies as leading candidates for reducing global CO₂ emissions and thus reducing the threat of global warming. However, it is to date unclear how pending climate legislation or regulations will affect CHP markets.

A substantial environmental barrier for CHP installations is the air quality permitting process. The process can be long, complex and costly, and varies by state.

Figure 0-15: States with Output-Based Emissions Requirements

Source: ACEEE

In California, for example, the complexity results from differing regulatory requirements of the various air quality districts in the state. For example, CA air quality districts that exceed established ozone standards have more stringent permitting requirements, as well as source specific requirements, compared to the requirements of districts that meet the ozone standards. The time to obtain a permit can be long if the installation must be evaluated under stringent New Source Review (NSR) rules.⁴ In addition, demonstrating that a type of emissions control technology is not feasible or not cost-effective can lead to lengthy negotiations with the local air district, as well as oversight from state and federal agencies.

Renewable Portfolio Standards

An important driver for CHP installations in the U.S. is whether or not a state's RPS (Renewable Portfolio Standard) has a specific CHP target or carve-out. Figure 3-17 shows which U.S. states include CHP installations as part of their RPS requirements.

Figure 0-16: States with Portfolio Requirements that Include CHP

⁴ For a summary of New Source Review regulations and permitting requirements by state, see: <http://www.epa.gov/NSR/>

Source: EPA (North Dakota and Nevada include waste heat CHP only)

Table 0-7 offers an overview of the renewable fuel sources included in each state's RPS requirements.

Table 0-7: Resource Eligibility under Current State RPS Policies

Energy Source	Biomass	Biofuels	CHP/Waste Heat	Energy Efficiency	Fuel Cells ^b	Geothermal	Hydro	Landfill Gas	Municipal Waste	Ocean Thermal	Photovoltaics	Solar Thermal Electric	Tidal	Waste Tire	Wave	Wind
AZ	*		*			*	*	*			*	*				*
CA	*	*				*	*	*	*	*	*	*	*		*	*
CO	*		*			*	*	*			*	*				*
CT	*		*	*	*		*	*	*	*	*	*	*		*	*
DE	*					*	*	*			*	*	*		*	*
DC	*					*	*	*	*	*	*	*	*		*	*
HI	*	*	*	*		*	*	*	*	*	*	*	*		*	*
IA	*						*	*	*		*	*				*
IL	*	*		*			*	*			*	*				*
MA	*	*	*			*	*	*	*	*	*	*	*		*	*
MD	*					*	*	*	*	*	*	*	*		*	*
ME	*					*	*	*			*	*	*			*
MN	*				*		*	*	*		*	*	*			*
MO ^a	*			*			*	*			*	*				*
MT	*					*	*	*			*	*				*
NC	*		*	*		*	*	*			*	*	*		*	*
ND ^a	*		*			*	*	*			*	*				*
NH	*	*				*	*	*	*	*	*	*	*		*	*
NJ	*					*	*	*	*		*	*	*		*	*
NM	*					*	*	*			*	*				*
NV	*	*	*	*		*	*	*	*		*	*		*		*
NY	*	*			*		*	*		*	*	*	*		*	*
OH	*		*	*	*	*	*	*	*	*	*	*	*			*
OR	*					*	*	*	*	*	*	*	*		*	*
PA	*		*	*	*	*	*	*	*		*	*				*
RI	*	*				*	*	*		*	*	*	*		*	*
SD	*		*			*	*	*	*		*	*				*
TX	*					*	*	*		*	*	*	*		*	*
UT	*		*			*	*	*		*	*	*	*		*	*
VA ^a	*					*	*				*	*	*		*	*
VT ^a	*					*	*				*	*	*			*
WA	*	*	*	*		*	*	*		*	*	*	*		*	*
WI	*					*	*	*			*	*	*		*	*

Source: KEMA

Notes on table:

a States with RPS goals not mandatory requirements.

b Includes only those states that allow fuel cells using nonrenewable energy sources of hydrogen. Some states allow only renewable fuel cells (Arizona, California, Colorado, Delaware, Massachusetts, Maryland, Missouri, New Mexico, New York, Rhode Island, Wisconsin) as eligible technologies.

c Renewable CHP systems are eligible; fossil-fueled CHP systems are not eligible.

d After January 1, 2010, hydrogen must be generated by renewable energy sources.

Rate Design

Depending on the specific cogeneration system design, operating conditions, and load requirements of the end user's facility, the system may provide anywhere from zero to greater than 100 percent of electricity needs at any given time. When a unit produces less than the full electricity requirements, power is purchased from the grid. When the unit produces more than is required, power can be sold back to the grid – dependent upon whether the utilities in a given state have net metering in place that prices the excess generation if it can be fed into the grid.

Overview. A customer with an onsite CHP system usually requires standby power from the local utility in case of onsite generation outages or routine system maintenance. A customer must pay the utility for the capacity and energy supplied in such circumstances (back-up energy) as well as facility demand charges. Utility customers (whether they generate power on-site or not) pay rates based on their assumed pattern of use during peak periods. This rate assumes all customers have high energy demands during the system peak. However, CHP customers, unlike non-generating customers, are not as likely to demand energy from the system coincidentally during the system peak under normal operating conditions.

Some of the rate issues that states have/are addressing related to CHP include:⁵

- **Exit fees.** Exit (or stranded asset recovery) fees have typically appeared in states that have restructured their electric utility. To avoid potential rate increases due to load loss, utilities may be authorized to assess exit fees on departing loads to recover the fixed costs of capital assets without shifting these costs onto remaining customers. However, many factors affect utility rates and revenues (e.g., customer growth, climate, fuel prices, and overall economic conditions).
- **Standby rates.** Facilities that use renewables or CHP usually need to have standby power accessible when the system is unavailable. For these facilities, electric utilities often assess standby charges to cover the additional costs of the generating, transmission, or distribution capacity required to supply intermittent service. The utility's concern is that the facility will require power at a time when electricity is scarce or at a premium cost, and that it must be prepared to serve energy loads during such extreme conditions. Nevertheless, the probability that all interconnected small-scale distributed generators will need power at the same time is relatively low. Consequently, some states are exploring alternatives to standby rates that may more accurately reflect realistic system operating conditions.

⁵ Source: U.S. EPA Combined Heat and Power Partnership

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- **Buyback rates.** Renewable and CHP projects may have electricity to sell back to the grid, either intermittently or continuously. The payment received for this power can be a critical component of project economics. The price that the utility is willing to pay can vary widely and is affected by federal requirements (e.g., Public Utilities Regulatory Policy Act standards) and other state policies.
 - **Gas rates for CHP facilities.** Some states, including New York, California and Connecticut, have established special favorable natural gas rates for CHP facilities. For example, New York had required that gas rates for Distributed Generation (DG, or customer-owned generation) applications be frozen until 2007 to provide economic certainty to developers. California offers a significant discount in its transmission and distribution rate to cogeneration facilities. Connecticut waives the natural gas delivery charges for customer-sited DG.

Rate Decoupling. In order to eliminate utility disincentives to promote energy efficiency, mechanisms need to be in place to “decouple” utility sales (deliveries) from the revenues they receive from those sales. This is done through “revenue decoupling mechanisms.” It is the jurisdiction of each state whether or not they pursue decoupling. In states that are not decoupled, when customers conserve energy, they pay a lower variable energy charge and the same fixed charges; since some fixed costs are included in variable rates, the utility does not recover all of their fixed costs when customers conserve energy. As a result, a utility without a decoupling mechanism experiences a shortfall of revenues and a lower rate of return when customers conserve, resulting in a disincentive for the utility to actively promote energy efficiency programs.⁶

In California, Massachusetts and Connecticut, all electric utilities must have some form of decoupling program in place, or include a decoupling plan in their next rate case. California’s policy combines the revenue decoupling program with performance incentives for meeting or exceeding energy efficiency targets. In Connecticut, the type of decoupling is assigned on a utility-by-utility basis. Massachusetts determines the target revenues on a utility-wide basis that can be adjusted for inflation and capital spending requirements. In other states, including Wisconsin, Vermont, Oregon, New York, Maryland, and Idaho decoupling programs have been approved and are beginning to be implemented for at least one electric utility.

⁶ National Association of Regulatory Utility Commissioners (NARUC), 2008.

Decoupling is an important policy that can vary in how it is implemented among markets, but plays into the overall picture of how utilities view energy efficiency measures (such as CHP) from a revenue perspective for their shareholders.⁷

Table 3-7 shows a summary of rate policies regarding CHPs in each of the top five states noted by ACEEE as being most favorable to CHP development (Table 0-2).

⁷ In 2010, The U.S. Department of Energy published a comprehensive analysis of decoupling policies – see: <http://www1.eere.energy.gov/industry/states/pdfs/nat-gas-revenue-decoupling-final.pdf>

Table 0-8: Key CHP Rate Provisions in Key State Markets

State	Standby Rates	Exit Fees	Revenue Decoupling Provision?
CA	<p>Statewide policy concerning standby rates in California via CPUC Decision 01-07-027 - standby rates must 1) provide for fair cost allocation among customers; 2) allow the utility adequate cost recovery while minimizing costs to customers; 3) facilitate customer-side distributed generation deployment; and 4) send proper price signals to prospective purchasers of distributed generation. Two CA utility examples: SCE and PG&E with source links to tariffs:</p> <p>Southern California Edison - Schedule S: Standby service is provided to customers that contract with the utility for a specific amount of standby capacity. A moderate demand based reservation charge is assessed every month. Actual usage is billed through a high demand charge and a moderate energy charge. Billing demand is based on the maximum 15 minute demand of the month. Rates are available at: http://www.sce.com/AboutSCE/Regulatory/tariffbooks/ratespricing/</p> <p>Pacific Gas & Electric - Schedule S: Standby service is provided to customers that contract with the utility for a specific amount of standby capacity. A moderate demand based reservation charge and a customer charge is assessed every month. Actual usage is billed through a high energy charge. Rate available at: http://www.pge.com/tariffs/ERS.SHTML#ERS</p>	<p>California's exit fees for DG have a number of components and exceptions and are fairly complex if one is not versed in CA rates and the legacy charges associated with the state's evolving retail markets.</p> <p>A summary of CA's exit fee components, levels, exceptions, and rate examples are available here: http://www.eea-inc.com/rrdb/DGRegProject/States/Newsite/CArevised.html</p>	Yes
NY	<p>Distributed generation with a nameplate rating of no greater than 15% of the customer's energy demand and "Designated Technology Customers" defined as those with generators that became operational between July 29, 2004 and May 31, 2006 and using either fuel cells, wind, solar thermal PV, sustainable managed biomass, tidal, geothermal, or methane waste; or small efficient CHP of less than 1 MW also qualify for an exemption from standby rates. Any "Smart Grid" sited after February 2011 is subject to the full standby rate.</p> <p>Customers can choose hourly integrated energy pricing, which can help the customer manage its electric demand cost-effectively or under certain conditions, the utility and a customer could negotiate an individual agreement governing a customer's election to disconnect itself from the grid, and an individual agreement establishing standby rates for a customer that sells most of its energy output to third parties.</p> <p>Provision to ratchet the contract demand charge upward according to the customer's highest demand over the most recent 12 months. For customers that choose to determine the contract demand level themselves instead of accepting the utility's determination, there are penalty provisions should the customer exceed the nominated demand level more than once.</p>	<p>A single utility (Niagara Mohawk) in the state of New York has been given authority by the PSC to assess an exit fee upon customers who exit the grid. See Niagara Mohawk Power Corporation, P.S.C. Tariff No. 207 Electricity, section 52 (Leaves Nos. 71 - Z13 through 71 - Z15).</p> <p>The exit fee does not apply if a self-generating customer completely isolates itself from the Niagara Mohawk system or if its electricity is supplied by an on-site third party that installed its generating capacity after January 1, 2000 and serves only a single customer. If a third party elects to be connected to Niagara Mohawk's system, they must deliver excess energy to the grid in addition to entering into an agreement under S.C. No. 7, Niagara Mohawk's standby tariff for retail service.</p>	No *

* applies a CHP thermal credit

Table 3-7: Key CHP Rate Provisions in Key State Markets (Continued...)

State	Standby Rates	Exit Fees	Revenue Decoupling Provision?
PA	<p>Pennsylvania does not have a statewide policy on standby rates. Relevant policies for Pennsylvania utilities vary. PECO example with source link to standby service rider:</p> <p>PECO Auxiliary Service Rider - standby service is provided when a customer contracts with the utility for a specified amount of demand capacity. Standby demand charges are based on contract demand and actual energy use.</p> <p>Applies to: qualifying facilities or small power producers and cogenerators as defined by PURPA whose electrical requirements are partially or wholly provided by facilities not owned by PECO.</p>	<p>Customers must pay an exit fee for the loss of load to the utility's system and they are liable for their fully allocated share of transition (to retail electric market) costs. This cost is recouped through a competitive transition charge through 2010 for some PA utilities. Some utilities, predominately ones without nuclear generator assets, have already recovered their stranded costs, including Duquene Light and FirstEnergy.</p>	No
TX	<p>Texas does not have a statewide policy on standby rates. Policies for individual utilities are summarized below.</p> <p>TXU Energy - There is no standard standby rate. Customers seeking standby service would need to contract with the utility to be charged under a regular tariff. Typical rates are based on both demand and energy charges. There may be a demand ratchet depending on the contract with the utility.</p> <p>Reliant Energy Retail Services - There is no standard standby rate. Customers seeking standby service would need to contract with the utility to be charged under a regular tariff. Typical rates are based on both demand and energy charges. There would be no demand ratchet.</p>	<p>There are no exit fees for DG applications smaller than 10 MW.</p>	No
OH	<p>Ohio does not have a statewide policy on standby rates. Relevant provisions for Ohio utilities are summarized below.</p> <p>Ohio Power Co (AEP) - Schedule OAD-SBS: Delivery of standby energy is provided through Ohio Power but the energy commodity must be purchased through another provider. The standby fee is entirely demand based and billed from the contract demand. Rate information is available at: https://www.aepohio.com/Customerservice/RatesAndTariffs/LegalTariffFilings/ohio.aspx</p> <p>Cincinnati Gas & Electric Company (Duke Energy) - Rate DP: There is no standard standby rate, however utility personnel indicated that on-site generation customers would be charged under Rate DP. Charges are primarily demand based. Billing demand is based on the higher of the maximum 15 minute demand of the month or 85% of the maximum from the previous 11 months. Rate information is available at: http://www.duke-energy.com/rates/ohio/electric.asp</p>	<p>According to the PUC there are no exit fees for DG applications in the state of Ohio</p>	No *

* applies a CHP thermal credit

Interconnection Requirements

On a state-by-state basis, there is a wide degree of variety and disparity in standards, policies, and requirements for customers to access and interconnect their onsite generation to the grid. As of 2010, eighteen states had no interconnection standards, as reflected in Figure 0-17.⁸ In states without interconnection policies, individual electric utilities define the procedures that affect distributed generation installations. Interconnection requirements vary by utility and are often not based on state-of-the-art technology or data. Interconnection is at its root a cost and “utility acceptance” issue. Utility resistance can add significant cost in the form of high interconnection fees, studies, and additional hardware.

Figure 0-17: State Interconnection Standards: Assessment of DG Favorability⁹

EPA Interconnection Assessment Favorability – Methodology. The EPA assessed the DG friendliness of existing interconnection rules through the following criteria:

⁸ U.S. EPA CHP Partnership, 2010 (<http://www.epa.gov/chp/state-policy/interconnection.html>)

⁹ Ibid.

Favorable: Indicates that there is a well-defined interconnection policy in place that has at least one or more beneficial attributes:

- Standard forms
- A reasonable timeline for application approval
- Low or no additional insurance requirements
- Allows for >10 kW residential and >100 kW commercial DG units to interconnect
- May have additional positive attributes

Neutral: Indicates that there is an interconnection policy, but overall the policy cannot be considered either beneficial or detrimental to DG.

Unfavorable: Indicates that the interconnection policy may be available, but has unfavorable requirements such as:

- Only allowing small units to interconnect (<10 kW residential and <100 kW commercial)
- Having high liability insurance requirements
- Requiring owners/operators to pay large interconnect study fees
- May have other burdensome requirements
- EPA assessed 50 states and the District of Columbia and found the following results:
 - 55 percent have standard interconnection forms
 - 29 percent have a simplified procedure for smaller systems
 - 35 percent have a set timeline for application approval
 - 45 percent have larger system size limits (over 10 kW for residential and over 100 kW for commercial systems)

Non-standard interconnection requirements make it difficult for equipment manufacturers to design and produce modular, pre-approved packages and to realize economies of scale across state markets. Despite the standardized technical interconnection requirements established (such as IEEE 1547 and UL 1741), the disparate state requirements have historically been a factor for distributors and end use customers to consider when making CHP installation decisions in specific U.S. markets.

Federal, State-Specific CHP Policy Drivers

Federal and state energy and tax policies are an important driver in determining the competitive landscape of the CHP markets in the U.S. The lack of a federal policy on carbon and greenhouse gas

emissions to date has historically favored traditional centralized resources over distributed generation resource development. Federal policies are comprised of numerous laws, regulations, incentives, and penalties.

Federal Policies Driving CHP Development. Table 0-9 summarizes the federal key policies that have established CHP-specific provisions in order to develop these technologies.

Table 0-9: Key Federal CHP Policies

Federal Initiative	Year	Key CHP Provision(s)
DOE CHP Challenge	1998	Program with a goal to double the amount of CHP capacity in U.S. electric power generation by 2010, an national increase of 50 GW. Launched with an action plan to identify barriers to CHP development, develop new policy and market mechanisms, expand CHP markets, and promote advanced technologies.
IEEE Interconnection Standards for DG	2003	Standard established criteria and requirements for interconnection of distributed resources (DR) with electric power systems (EPS).
Energy Independence and Security Act	2007	Title IV, Section D contains provisions designed to improve energy efficiency by promoting CHP, waste energy recovery and district energy.
Energy Improvement and Extension Act	2008	Provided a 10 percent investment tax credit (ITC) for the first 15 MW of CHP property; CHP qualifies for 5 year depreciation under Modified Accelerated Cost Recovery System (MACRS).
American Recovery and Reinvestment Act	2009	\$156 million of cost-share grants for CHP, waste energy recovery, district energy, and industrial-efficiency projects; allows "bonus depreciation" for CHP where 50 percent of depreciation value can be taken in the first year (remainder over the following four years).

Advanced Research Project Agency-Energy (ARPA-E) CHP Initiative.¹⁰

On June 1-2 (2011) ARPA held workshops to collaborate with a range of stakeholders on high efficiency gensets (1 MW or less), with the objectives to:

- Identify major end-use requirements in the small-scale (<1 MW) distributed generation market segments;
- Identify most-challenging technical barriers to very high efficiency, low-cost gensets; and
- Identify promising new R&D paths to meet identified challenges.

State and Regional CHP Resources.

In addition to federal and state policy drivers, the U.S. DOE's Clean Energy Application Centers, formerly known as the Regional Application Centers (RACs), provide education, awareness, training, and outreach on CHP, waste heat recovery, and district energy systems. These services include on-site analyses to help businesses, facility managers, and building engineers determine the most cost-effective applications for CHP and waste heat recovery. The Centers also provide technical support to policy development efforts by DOE, state governments, and other organizations. The national labs provide program support and technical guidance to all Centers.

- DOE has developed a range of tools to address CHP market development and the educational needs of end users, product developers, project managers, and policymakers. Among these tools are databases, software, guidebooks, and policy documents, including: CHP Project Installation Database, which tracks installed CHP projects in all end-use sectors for all fifty states.
http://www1.eere.energy.gov/industry/distributedenergy/chp_database/Default.aspx
- CHP Economic Evaluation Software Tool, which allows project developers and end users to determine the cost effectiveness of CHP projects in industrial, commercial, and institutional facilities. <http://www.chpcentermw.org/docs/20040913CHPAssessorMAC.xls>

¹⁰ ARPA-E June 1, 2, 2011 workshop summary @ <http://arpa-e.energy.gov/eventsworkshops/workshops/tabid/171/vw/3/itemid/37/d/20110601/Small-Scale-Distributed-Generation-.aspx>

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- CHP Resource Guide, produced by the Midwest Center, to provide project assessment and evaluation guidance, regulatory and policy information, and other analytical tools for potential CHP project developers and installers.
http://www.chpcentermw.org/pdfs/Resource_Guide_10312005_Final_Rev5.pdf
 - Distributed Generation Operational Reliability and Availability Database, which tracks large CHP projects in operation throughout the country.
<http://www1.eere.energy.gov/industry/distributedenergy/databases.html>
 - CHP Emissions/Credit Calculator, which provides detailed assessment tools for estimating the emissions impacts of CHP projects.
http://www.chpcentermw.org/pdfs/030123-PermitGuidebook-EmCalc_IL.xls

CHP Supply Chain Overview

Most CHP applications are installed by a developer that is trusted by the end-users. Motivating developers to sell the product, maintain end user relationships, and represent the manufacturer's product effectively and as intended is essential. A strong distributor network and education program targeted at developers of applications is an important dynamic of the CHP supply chain, as depicted at a high level in Figure 0-18.

It is difficult to generalize the dynamics of the distributor-manufacturer network, since complexities can arise based on market dynamics, CHP applications, end user landscape and requirements, and prior work history. An essential link in this supply chain is establishing a solid communication strategy between the manufacturer and the developer(s) being leveraged in specific markets. In addition, training on product pitch nuances and pricing/savings, as well as clear expectations about how developers communicate back to the manufacturer end user feedback and issues is critical.

Figure 0-18: CHP Supply Chain Overview

Emerging U.S. Challenges, Opportunities

Distributed Generation Rates. Several states are attempting to ensure that rates are based on accurate measurement of the costs and benefits of clean DG applications. For example, California has funded a study that investigates the effects of DG on the performance of an electric power transmission and distribution system. This report presents a methodology to quantify the potential benefits of these projects. NGRID in Massachusetts and Rhode Island requires a cost benefit test in order to provide qualifying CHP systems with an installation incentive of \$750/kW.

Many states are also investigating the benefits that customer-owned generation can provide (e.g., increased system capacity, potential deferral of transmission and distribution investment, reduced system losses, improved stability from reactive power and voltage support). However, states vary in their prioritization of this exploration, and their ability to devote staff and resources to collect data and understand trends to use as a foundation for subsequent policy changes.

Revenue Decoupling. The term "decoupling" refers to the effort to sever the link between utility sales and revenues (addressed in more detail in Section 3.3.4). In practice, this means that the state utility commission periodically conducts a "true up" any difference between a utility's actual sales for a particular year and sales projections submitted by the utility as part of its revenue requirement. This true-up mechanism affects customer rates: higher than expected sales lead to a rate decrease, while lower than expected sales lead to a rate increase. Actual utility earnings are thus brought in line with earnings authorized by the governing body, removing – or at least mitigating – the utility's disincentive to invest in energy efficiency programs due to reduced sales. Therefore, how a utility's revenues are affected by customer-owned generation are uniquely driven by this fundamental decoupling issue.

National Renewable Energy Standard. The most likely federal policy change that would have a major immediate effect on biomass development is the creation of a national Renewable Energy Standard (RES). Depending upon specific provisions, a national RES would likely create strong biomass markets in the Southeast, which has limited wind and geothermal resources. In September 2010, U.S. Senators Bingaman and Udall introduced bipartisan legislation to create the first-ever national renewable electricity standard (RES), which failed to reach the floor in that session. In the current political and economic climate, chances for this bills reintroduction are low.

The prior proposal included the following renewable energy procurement targets; however, there was no separate carve-out for CHP in the bill:

- 4 percent by 2011

-
- 8 percent by 2013
 - 12 percent by 2016
 - 16 percent by 2019
 - 20 percent by 2021

CHP systems are treated differently under the current system depending on how each state law is configured and whether CHP applications are included in the renewable mandates. If utilities or other load-serving entities (LSEs) were required to purchase energy delivered into their markets—or into adjacent markets—this could reshape the market landscape for renewables, making the Southeast potentially more attractive for CHP.

National Cap & Trade System. Although there are three regional greenhouse gas (GHG) cap & trade systems in the United States (the Northeast Regional Greenhouse Gas Initiative (RGGI)¹¹, California's AB 32¹², and the Western Climate Initiative¹³), there is currently no federal system to incorporate the price of carbon into the cost of consuming fossil fuels. The Obama Administration and Democratic leaders in the legislature have expressed strong support for such a system.

¹¹ <http://www.rggi.org/>

¹² <http://www.climatechange.ca.gov/>

¹³ <http://www.westernclimateinitiative.org/>

European Market Study

European CHP Policy

Europe is unquestionably the global leader in promotion and adoption of CHP. Over the past decade, a number of European governments have enacted policies designed to increase the penetration of CHP as part of a broader commitment to energy efficiency and to achieve environmental and energy security objectives. This section summarizes the key government policies that have contributed to the success of CHP applications in Europe.

Overview of European CHP Markets

The penetration and growth of CHP in Europe has been highly variable by country. As of 2007, there was nearly 100 GW of installed cogeneration capacity in 27 Member States¹⁴. Figure 0-19 reflects the overall European generation profile from 1972 – 2008.

Figure 0-19: European Generation Profile 1972 - 2008

Source: IEA

The European energy mix is well diversified. Coal power has flat lined while oil continues to trend towards extinction in the power generation sector. Affordable natural gas, primarily supplied by

¹⁴ CODE Project 2009, *Preliminary analysis of the reports on cogeneration potential in the EU Member states*.

sources from Russia, the North Sea, and the Caspian Sea, has dramatically increased market share since 1992. Nuclear generation expanded significantly in the late 1970s and early 1980s, but has since remained flat. Renewables (the orange and red areas in Figure 0-19), have grown significantly, but still comprise a small portion of the overall energy mix.

Figure 0-20 shows the share of cogenerated electricity as a portion of total electricity generation in 2007 in EU member states. Finland, Denmark, Latvia, and the Netherlands all have high penetration of over 30 percent CHP in their electrical supply. Slovakia, Hungary, Germany, Poland, Czech Republic, Austria, Portugal and Belgium also show medium to high penetration of CHP.

Figure 0-20: Share of Cogeneration in Total Electricity Generation in Europe, 2007¹⁵

Table 0-10 shows the penetration trends in all EU-27 states from 2004 to 2008 and Figure 0-20: Share of Cogeneration in Total Electricity Generation in Europe, 2007. Figure 0-20 graphically illustrates this data. While all CHP generation is aggregated in this data, from micro turbines through large industrial applications, it is illustrative to reflect which countries have had the most growth and highest penetration of CHP.

¹⁵ CODE Project, December 2010. *European Summary Report on CHP Support Schemes*.

Table 0-10: Percentage of CHP in Gross Generation¹⁶

	1994	1996	1997	1998	2000	2002	2004	2005	2006	2007	2008	2009
European Union	:	:	:	:	:	:	10.5	11.1	10.9	10.9	11	11.4
Belgium	3.4	3.9	3.9	4.1	6.5	7.5	8.4	8.5	8.7	12.5	:	14.5
Bulgaria	:	:	:	:	:	:	7.3	6.1	6	9.4	10	9.4
Czech Republic	:	:	:	:	:	17.1	16.4	16.8	15.1	13	14.2	13.4
Denmark	54.5	54.6	59.9	62.3	52.6	49.1	50	52.1	40.7	42.8	46.1	45.3
Germany	9	6.8	6.7	7.5	10.6	9.8	9.3	12.6	12.5	12.2	12.5	13
Estonia	:	:	:	:	:	11	9.9	10.2	10.7	7.2	8.6	9.2
Ireland	1.5	1.9	2.3	1.9	2.4	2.5	2.6	2.4	5.6	6.3	6.2	6.3
Greece	2	2.1	2.2	2.1	2.1	1.9	1.5	1.7	1.7	1.6	1.9	3
Spain	5.3	7.7	9.8	11.2	9.2	7.8	7.9	7.8	7.2	7.1	7	7.5
France	1.8	1.9	2.1	2.5	3	4	4.1	4	3.2	3.2	3.1	4.3
Italy	11.4	12.9	16	17.3	8.3	7.4	8.1	9	9.8	10.3	9.5	10.2
Cyprus	0	0	0	0	0	0	0	0.3	0.3	0.3	0.3	0.4
Latvia	:	:	:	:	:	37.5	32	30.7	42.6	40.9	33.6	19.7
Lithuania	:	:	:	:	:	9.7	11.6	15.5	14.3	13.2	12.7	13.9
Luxembourg	:	:	9.5	22.5	17.7	7.9	10.6	10.1	10.9	9.9	11.9	10.1
Hungary	:	:	:	:	:	21.5	18.2	19.1	22.4	21.4	21.1	20.5
Malta	0	0	0	0	0	0	0	0	0	0	0	0
Netherlands	39.5	42.7	47.9	52.6	37.6	29.9	29.5	29.4	29.9	30.1	33.6	32.1
Austria	21.4	24.7	24.7	24.8	10.4	13.6	15.2	15.4	16.1	15.6	15.3	13.2
Poland	:	:	:	:	:	16	17	16.8	16	17.3	16.9	17.2
Portugal	9.9	8.2	8.6	8.4	10	10	11	11.6	11.6	12.3	11.9	11
Romania	:	:	:	:	:	:	26.4	26.2	18	10.7	9.6	10.8
Slovenia	:	:	:	:	:	5.9	6.4	7.3	7.4	7.2	6.7	6.2
Slovakia	:	:	:	:	:	17.5	15.3	15.3	27.6	25.6	24	19.2
Finland	30.9	32.5	33.3	35.8	36.4	38	34	38.9	34.9	34.4	35.6	35.8
Sweden	6.4	7.3	6.2	6	5.9	6.8	8.1	6.7	8	8.2	9.6	10.5
United Kingdom	3.6	4.3	4.9	5.2	6.1	5.4	6.7	6.8	6.3	6.4	6.4	6.5
Iceland	:	:	:	:	:	:	:	:	14.4	14.4	:	:
Norway	:	:	:	:	:	:	:	:	0.1	0.1	0.1	0.1
Croatia	:	:	:	:	:	:	:	:	:	:	:	12.7
Turkey	:	:	:	:	:	:	4.0	4.4	4.4	4.6	4.2	3.8

¹⁶ Eurostat, 2010. Finland, Denmark, Latvia, and the Netherlands are highlighted, as each have >30 percent CHP in their electrical supply.

Figure 0-21: EU Country Percentage CHP Generation, 2000 - 2009¹⁷

¹⁷ Eurostat, 2010

The share of electricity produced by cogeneration processes in the EU-27 increased to 11 percent in 2008, a moderate increase of 0.5 percentage points from 2004. However, significant differences in CHP adoption trends can be observed amongst different countries. Between 2004 and 2008, Romania recorded the highest decrease in its CHP share from 26.4 percent in 1998 to 9.6 percent in 2008. For the same period, Slovakia reported an increase of 8.7 percentage points, with its 2008 CHP share reaching 24 percent. Belgium experienced significant growth between 2006 and 2007, while many countries experienced a decrease in CHP generation, including: England, Spain, France, and the Czech Republic.

In general, the most important markets for CHP are: industry (primarily paper and chemicals), agriculture (primarily greenhouses), waste treatment (including incineration and wastewater treatment), office buildings, hospitals, and district heating. CHP engines in the 1 – 5 MW size range are typically found in greenhouses, hospitals, and large campuses of buildings. For example, in Denmark and Germany, district heating using multiple gas engines is common. A detailed breakdown of the CHP market in individual countries is presented in Section 4.2.

European Policy and Regulatory Landscape

Policies promoting CHP in Europe vary widely across member states, some of which have mature CHP support policies while others have virtually no policy. The following describes the European CHP policy landscape and highlights the steps taken by proactive countries, which include: Germany, Belgium, the Netherlands, Denmark, and Finland.

European Emissions Trading System (EU ETS)

The EU Emissions Trading System (ETS) is a mandatory “cap and trade” emissions trading scheme for energy-intensive activities such as: energy production (including CHP), petroleum refining, processing of ferrous metals, mineral production and processing, and paper processing. Each EU member state is given a “cap” or limit on the amount of greenhouse gas emissions that may be legally emitted each year based on the member state’s emission reduction target. Each member state is then required to produce a National Allocation Plan (NAP) with its rationale for distributing allowances to regulated emitters. Each allowance represents the emission of 1 metric ton of CO₂ equivalent. Allowances are distributed either by auction, politically distributed, or a hybrid approach. Each approach is a different method of distributing the value of an emissions permit. Political distribution has the effect of allowing policy makers to protect trade sensitive industries or protect energy consumers from spikes in energy prices. An auction provides for more price discovery and protects against over allocation and emissions price volatility.

Regardless of the emission allowance approach (allocation, auction, or a hybrid), the overall emissions cap creates a scarcity in emissions permits such that emitting greenhouse gases is associated with a cost. EU member states take different approaches to allocating allowances to the energy sector, therefore in some countries the price of carbon may drive up the cost of electricity, in turn making self-generation more attractive, and others may do more to protect consumers with ample free emissions allowances. In the past, the ETS did not have significant effect on energy prices due to an over allocation of emissions permits leading to low CO₂ prices. Starting in 2013, there will be a centralized allocation of permits, not NAPs, with a greater share of auctioning of permits. This may have the effect of driving up long term electricity prices higher than business-as-usual. The new system is not particularly favorable for CHP, since “free allowances” will only be allocated for the heat produced. According to a COGEN Europe analysis, “...even in the best scenarios, CHP plants will only receive marginal financial benefit, which is offset by increased market risk.”

Air Quality Regulations in Europe

The EU has been working to reduce air pollutants since the 1970s, driven by increased awareness of the adverse health impacts of high levels of substances like particulate matter (PM) and ozone in ambient air. EU policy has been particularly effective in reducing sulfur emissions which have fallen by 72 percent between 1990 and 2007. However, efforts to curb nitrogen emissions, which primarily emanate from agriculture and transport, have been less successful. Consequently, nitrogen has become the main acidifying pollutant in Europe’s air.

The 1996 EU Air Quality Framework Directive¹⁸ outlines the principles of assessing and managing air quality in member states. It lists limits and target values for a range of pollutants. The law was supplemented with four subsequent directives, introducing limit values for various air pollutants including sulfur and nitrogen dioxide, particulate matter (PM), and lead.

The 2001 EU National Emissions Ceiling Directive (NECD)¹⁹ introduced legally-binding emission limits on a number of air pollutants that cause acidification, eutrophication, and ground-level ozone pollution. The NECD established national ceilings for sulfur dioxide, nitrogen oxides, volatile organic compounds, and ammonia, which member states had to comply with by 2010.

Table 0-11 presents an overview of the air quality emissions requirements for natural gas engines in select European countries.

¹⁸ http://ec.europa.eu/environment/air/quality/legislation/existing_leg.htm

¹⁹ http://www.esig.org/mediaroom/487/52/national-emission-ceiling-directive-nec/?cntnt01template=display_recents&cntnt01currentpage=1&cntnt01orderby=Date+DESC

Table 0-11: Emissions Limits for Natural Gas Engines

Country	Emission Regulations for Natural Gas
The Netherlands	$\text{NO}_x \leq 100 \text{ mg/Nm}^3$ for $> 2500 \text{ kW}$ chemical input $\text{NO}_x \leq 340 \text{ mg/Nm}^3$ for $< 2500 \text{ kW}$ chemical input $\text{C in CxHy} \leq 1500 \text{ mg/Nm}^3$ At 3% O_2
Italy	$\text{NO}_x \leq 100 \text{ mg/Nm}^3$ for “zona critica” locations $\text{NO}_x \leq 250 \text{ mg/Nm}^3$ for other locations $\text{CO} \leq 200 \text{ mg/Nm}^3$ for “zona critica” locations $\text{CO} \leq 300 \text{ mg/Nm}^3$ for all other locations
Denmark	$\text{NO}_x \leq 550 \text{ mg/Nm}^3$ + tax of 5 DKK/kg $\text{CO} \leq 500 \text{ mg/Nm}^3$ $\text{CxHy} \leq 1500 \cdot \text{efficiency} / 30\% \text{ mg CxHy/Nm}^3$
Germany	$\text{NO}_x \leq 500 \text{ mg/Nm}^3$ $\text{CO} \leq 300 \text{ mg/Nm}^3$ $\text{CH}_2\text{O} \leq 60 \text{ mg/Nm}^3$
UK	$\text{NO}_x \leq 500 \text{ mg/Nm}^3$ $\text{NO}_x \leq 250 \text{ mg/Nm}^3$ in cities
France	$\text{NO}_x \leq 350 \text{ mg/Nm}^3$
Austria	$\text{NO}_x \leq 150 \text{ mg/Nm}^3$ for $> 2500 \text{ kW}$ chemical input
Other European countries	$\text{NO}_x \leq 500 \text{ mg/Nm}^3$ is typical

The EU Cogeneration Directive

The EU Cogeneration Directive, approved by the European Parliament in 2004 and updated in 2008, outlines an enabling policy framework for the European Union to expand the deployment of cogeneration. The purpose of the Cogeneration Directive is to “increase energy efficiency and improve security of supply by creating a framework for promotion and development of high efficiency cogeneration of heat and power based on useful heat demand and primary energy savings” in the internal energy market.²⁰ Member states were asked to assess their national potential for cogeneration, enact policies to remove barriers to CHP installation, and then update the European Commission on progress towards achieving the CHP potential.

²⁰ CODE Project, December, 2009. *Member State reporting under the Cogeneration Directive.*

The Directive does not establish CHP adoption targets for member states nor require any specific policy measures. Policy activity for the promotion of CHP was left to the discretion of each member state, and thus policy has been highly varied. While in some countries there has been clear growth driven by the member state's policies (Germany, Belgium) in other countries there is no activity or even a deterioration driven by poor economic conditions and changes in the electricity and heat markets. At this stage of implementation, the Directive has not been universally successful in stimulating growth in CHP across Europe.

The EU Commission's latest estimations suggest that the EU will achieve only half of the 20% target in 2020. The European Council and European Parliament have urged the Commission to adopt a new ambitious strategy on energy efficiency with action to tap the potential. On March 8th, 2011, the Commission put forward a new Energy Efficiency Plan (EEP)²¹ setting out measures to achieve further savings in energy supply and use. The two current directives have failed to fully tap the energy savings potential, (2004/8/EC, CHP Directive) and the (2006/32/EC, ESD) Energy Services Directive. They would be replaced by a new Energy Efficiency Directive (EED) put targets on Public Sector, Households, Services, Energy Supply and Industry. The proposal is in working group discussion with plans for agreement and implementation by December 2013.²²

Overview of CHP Support Mechanisms across Europe

The European Commission analysis ²³ of the growth of the total installed CHP capacity in Europe between 2004 and 2008 shows that the overall growth was on average 0.5 percent per year. However, this average rate mutes a wide variation across member states in CHP activity. Given the time required for legislation to be translated from the European level (i.e. the Cogeneration Directive) into member state law, there are only a few countries where national legislation arising from the CHP Directive in the years since 2004 can demonstrate market effects. The period 2004-2008 saw only a few member states increase their CHP capacity above what could be considered as "business-as-usual" growth. The Belgian region of Flanders stands out in this period as a region with exceptional growth in CHP installations. From 2000 to 2004, CHP installations in Flanders increased at approximately 2 percent per year. Between 2004 and 2008, CHP installations in Flanders increased

²¹ European Commission, July 2011. *Proposal for a Directive of the European Parliament and of the Council on energy efficiency and repealing Directives 2004/8/EC and 2006/32/EC.*

²² Directorate-General for Energy, June 2011. *A new Directive on Energy Efficiency – Challenges addressed & solutions proposed.*

http://ec.europa.eu/energy/efficiency/eed/doc/2011_directive/20110622_energy_efficiency_directive_slides_presentation_en.pdf

²³ CODE Project, December, 2009. *Member State reporting under the Cogeneration Directive.*

at over 20 percent per year. In the Netherlands, 500 MW of new CHP capacity was added annually from 2004 to 2008, nearly all in the greenhouse sector. In Germany, there were pockets of growth largely stimulated by bio-energy support mechanisms.

EU member states have generally favored some form of special tariff on electricity supplied to the grid, a “feed-in tariff” or generation bonus on CHP-generated electricity. These forms of support reduce the risk of the equipment investment by facilitating a cost offset that can be measured and included in ROI calculations. This approach is particularly successful when the time horizon for the support is clear and sufficiently long term to cover the near term life of the plant. Some sort of capital grant or allowance targeted at growing particular capacity sizes of CHP is also a popular approach, but selectively applied and less common. Grant or rebate support is particularly effective for smaller applications, where investment costs tend to be higher and more variable. The main methods of CHP incentives are addressed in Table 0-12 in the categories: tax, feed-in-tariff, certificate scheme, and capital grant. The “Other” category of support contains a range of detail and added complexity to these schemes which are not centrally motivating for the sector. For example, these might include feasibility study co-funding. The “Other” category also contains support mechanisms for bio-energy.

Table 0-12: Overview of European Support Mechanisms for CHP

Country	Tax Support	Feed in tariff	Certificate Scheme	Capital Grant	Other
Austria		✓			✓
BE- Flanders	✓		✓		✓
Bulgaria		✓			✓
Cyprus					✓
Czech Republic		✓			✓
Denmark		✓			✓
Estonia					✓
Finland					✓
France		✓			✓
Germany		✓			✓
Greece	✓	✓			✓
Hungary		✓			✓
Ireland					✓
Italy	✓	✓		✓	
Latvia		✓			✓
Lithuania		✓			✓
Luxembourg	✓				✓
Malta	✓				✓
Netherlands	✓	✓		✓	✓
Poland			✓		
Portugal				✓	✓
Romania		✓		✓	
Slovakia		✓			
Slovenia		✓			✓
Spain	✓	✓			✓
Sweden				✓	✓
United Kingdom	✓	✓		✓	

Finland, Denmark, Latvia, and the Netherlands are highlighted, as each have >30 percent CHP in their electrical supply.

A deeper analysis of the policies in a sample of countries that have had success in promoting CHP holds lessons for the U.S. as it considers actions to promote cogeneration. The following sections address the evolution of CHP policies in Germany, Belgium, and the Netherlands in depth. Portugal, Denmark, and Finland are also discussed briefly. These countries have been the most pro-active and

successful in promoting combined heat and power in the past decade. Finland provides a unique example of a country that held conditions favorable to CHP and required minimal government support.

Germany

Policies

Germany is a leader within Europe in promoting CHP. In 2008, Germany established an ambitious national target of 25 percent of electricity provided by CHP by 2020. The primary mechanism is a feed-in tariff.

In the late 1990s, as part of a broader European effort, the German electricity market was deregulated. In 2002, the German government adopted the Cogeneration Act to protect existing CHP operators from falling electricity prices that resulted from deregulation and promote new installations of CHP. The Cogeneration Act established a feed-in tariff for new CHP plants up to 2 MW. The tariff is constructed as follows:

- A basic fee equal to the average price for baseload power, updated quarterly from the European Energy Exchange (EEX).
- A fee for avoiding the use of high and medium voltage power. This fee typically ranges from 0.4 – 0.8 Eurocents (€ct)/kWh.
- A legal fee (the “feed-in-tariff”) of 5.11 €ct/kWh for CHP less than 50 kW. For 50 kW – 2 MW, the fee declines incrementally each year from 2.56 €ct/kWh in 2002 to 1.94 €ct/kWh in 2010.

An amendment was adopted by the German government in 2008,²⁴ which codified a target of 25 percent of electricity provided by cogeneration. This support was driven by the potential for CHP to reduce greenhouse gas emissions. According to government calculations, 25 percent CHP electricity (and heat) would achieve 13 percent of the 413 million metric ton reduction necessary to meet Germany’s “40 percent below 1990 levels” target by 2020.

The 2008 CHP law continued the support for CHP through a bonus tariff on the price of electricity and included the following changes:

- An obligation of network operators to connect CHP plants to the grid and buy their electricity with a dispatch priority, equivalent to that for renewable energy.

²⁴ <http://www.iea.org/textbase/pm/?mode=re&id=4054&action=detail>

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- The bonus was extended to modernized and new CHP plants that begin operations between 2007 and 2016.
 - The bonus eligibility was extended to customers who use electricity for their own consumption, extending the arrangements for power exported to public networks.
 - The 2 MW capacity limit was eliminated.
 - The extension and new construction of heat networks became eligible for support, if at least 60 percent of the heat is supplied by CHP.

All fuel(s) used in CHP units are not subject to petroleum and other eco-taxes. This is roughly equivalent to a 0.55 €/kWh subsidy for natural gas units.

Incentives to promote renewable energy have had a significant effect on the installation of biogas CHP units. A 2008 amendment to the Renewable Energy Sources Act (EEG)²⁵ set a new target for renewable energy in the electricity supply of 25-30 percent by 2020. Pursuant to the EEG, a feed-in tariff was established for renewable generation based on unit size and fuel type. Another bonus of 3.0 €/kWh was provided if the renewable fuel is combusted in a CHP unit. This feed-in-tariff is provided for 20 years. The first EEG law did not include CHP, which resulted in the proliferation of "electricity only" biogas plants. However under the 2008 amendment, the EEG specifically incentivizes CHP. However even under the old law, just before the economic downturn when biomass prices went up, the CHP biogas plants were the ones that stayed profitable (due to the revenue earned by selling the heat) where some of the "electricity only" biogas plants had problems or stopped producing.

Table 4-4 presents the German feed-in tariff structure for biogas in CHP.

²⁵ <http://www.erneuerbare-energien.de/inhalt/42934/>

Table 0-13: German Renewable Energy Act Feed-in Tariffs

Capacity Range	Basic rate for biomass (€/kWh)	Bonus for agricultural wastes and energy crops (€/kWh)	Bonus for CHP (€/kWh)	Maximum Price (€/kWh)
0 – 150 kW	11.67	11.0/9.0	3.0	25.67
150 – 500 kW	9.18	9.0	3.0	21.18
500 – 5000 kW	8.25	4.0	3.0	15.25
5.0MW – 20MW	7.79	0	3.0	10.79

Source: CODE Project, 2010

Emissions trading is central to reducing energy-related GHG emissions in Germany. Germany has a target of reducing its greenhouse gas emissions from 2008 to 2012 by 21 percent over 1990 levels established by the Kyoto Protocol. The government aims to reduce CO₂ emissions from the energy sector from 532.5 Mt/yr to 495 Mt/yr (from 2008 - 2012 through the emissions allocation of the EU ETS. Power-only plants will be responsible for the majority of the reductions, having to cut emissions by 15 percent relative to the 2000 – 2002 baseline (effectively 47.8 Mt/yr). Industry and CHP plants will only be required to make a 1.25 percent reduction (effectively 2.7Mt/yr). This further supports the position of CHP in Germany's electricity mix.

Market Effects

The 2002 law has been successful in promoting CHP primarily in plants with a capacity of up to 2 MW.

Table 0-14: Growth of Reciprocating Engine CHP in Germany, 2004 - 2006

	2004	2005	2006
Number of Recip. CHP Plants	693	859	936
Electrical Capacity (MWe)	765	894	945
Thermal Capacity (MWth)	1227	1585	1558

Source: German Federal Ministry of Economics and Technology

This expansion was mainly confined to small cogeneration plants with a capacity of up to 2 MW. In the 50 kW sector in particular, approximately 10,000 new plants became operational between 2002

and 2006. The original 2002 law was primarily focused on promoting CHP under 2 MW. Since that restriction was lifted in 2008, future evaluations may show growth in the 2 MW and larger space.

The number of biogas CHP plants in Germany has grown rapidly since 2000, with 335 MW of new capacity in 2006 alone. In 2007, over 3,700 units were operating, representing 1,271 MW of capacity.

Figure 0-22: Growth in Biogas (all plants) CHP Capacity (MW) in Germany

Source: IEA CHP/DHC Collaborative Country Scorecard: Germany

Biomass has been the primary beneficiary of the subsidization scheme, having grown rapidly since 2000. In 2000, there was 180 MW of installed biogas CHP capacity. In 2007, over 3,700 units were operating, representing 1,271 MW of capacity. The Renewable Energy law (EEG) has been the driving factor on the successful development of the biogas CHP sector in Germany. Overall, the Cogeneration Law covered 87% of the installed CHP capacities in Germany. Existing plants accounted for 80% of subsidized power generation.²⁶

²⁶ Deutsche Bank, 2008. *Combined Heat and Power: A pillar of Germany's integrated energy and climate programme.*

Belgium

Policies

The Kingdom of Belgium is divided into three regions: the Flemish-speaking Flanders region in the north (55 percent of the population), the French-speaking Wallonia region in the South (45 percent of the population), and the Brussels-Capital region. Each region is semi-autonomous.

Unlike most other European countries, Belgium does not use a feed-in-tariff system to incentivize CHP. Instead, each region uses a "white certificate" system for CHP and a "green certificate" system for renewables. In these schemes, CHP installations receive white certificates based on the greenhouse gas emission reductions below the baseline emissions that would have occurred based on separate generation of heat and power. Electric utilities are required to surrender a certain amount of certificates to the government every year. CHP owners sell certificates to utilities needing to meet their compliance obligations. This is an important source of revenue for CHP operators and the primary source of income for biomass CHP operators.

Each region's CHP policy is slightly different. Brussels has a green certificate mechanism in which the owner receives certificates worth €90 per 217 kg of CO₂ reduced. Also, twenty percent of investment costs in a CHP unit can be reimbursed by the government. The government also pays 50 percent of a CHP feasibility study. Under Wallonia's green certificate mechanism, a natural gas CHP unit can receive approximately €25/MWh because of the 120 kg of CO₂ avoided by each MWh produced. A Wallonian biomass CHP unit receives up to 180 €/MWh (savings of 900 kg CO₂/MWh). For the public and non-profit sectors, the government offers grants 30 percent of the investment cost in a quality CHP unit. In the private sector, the government offers grants up to 20 percent of the investment costs for CHP installations (with a €1,000,000 ceiling for small-to-medium enterprises).

The bulk of installed CHP in Belgium are located in Flanders. The Flemish region accounts for about 900 MW of installed CHP capacity and studies have identified an additional potential of 1,300 MW; of this, 900 MW will be developed by the regional government by 2012. The support mechanisms currently available for CHP in Flanders include:

- **Tax reduction** – A tax reduction is available to co-generators on taxable profit associated with investments in energy savings. This is an approximately 10 percent tax write off.
- **CHP Certificates** – In 2004, Flanders established a target of 19 percent electricity supply from high efficient CHP by 2010. This target requires all electric utilities to achieve a certain amount of primary energy savings by means of high efficiency CHP sources. Each utility is

required to deliver CHP certificates against the predetermined quota. High efficiency CHP operators can apply to the government regulators for CHP certificates. The certificates are then traded in a CHP certificate market where they are bought by the utilities seeking to meet their compliance obligation. One CHP certificate is the equivalent of one MWh of primary energy savings delivered through high efficiency CHP. The government provides a guaranteed minimum price for the certificates of €27 (for installations connected to the grid). If a supplier fails to meet its obligation in providing the regulator with the correct quota of certificates, the regulator will fine the supplier 45 Euros per each missing certificate.

In addition to these incentives, two additional mechanisms have contributed to CHP growth in the Flanders region, but are now expired. They are:

- **Premium for ecological investment (expired January 2011)** – This grant support was for projects that met certain environmental performance criteria. Grants up to 1.75 million € were administered under a “call for projects” system, with three calls per year. Since 2007, fossil fuel CHP projects were often ranked too low to be supported, however biomass CHP benefited from this program.
- **Twenty percent investment support for micro-CHP (expired June 2010)** – Twenty percent of the costs for installation were provided by a government grant.

Market Effects

Due to the incentive structures, the Flanders region has experienced exceptional growth in CHP installations, particularly in the small and medium sized applications. The growth of the installed capacity of cogeneration in Flanders is shown in Figure 4-18.

Figure 0-23: Growth in CHP capacity in Flanders, 2000 - 2008²⁷

Source: CODE Project, 2010. Note: STAG refers to a "Steam And Gas" combined cycle natural gas power plant

From 2000 to 2004, CHP grew in Flanders at approximately 2 percent per year. Between 2004 and 2008, CHP installations in Flanders increased at over 20 percent per year. The incentive mechanisms were implemented in 2004, and in the absence of any other major market changes, the dramatic growth in CHP installations has been a market response to the incentive programs.

The Netherlands

Policies

The Electricity Act of 1998 ended special treatment for cogeneration in the country by requiring that feed-in tariffs had to be negotiated in a competitive market. Special tariffs for transmission and distribution network benefits disappeared, which made back-up electricity for self-generators expensive.

A year later, the Electricity Act of 1989 established a feed-in tariff for CHP and paved the way for the development of joint ventures between energy distribution companies and industries. Because the rapid growth of CHP capacity in the early 1990s led to excess capacity in the power market, the government decided in 1994 to prohibit the construction of new CHP capacity above 2 MW.

²⁷ CODE Project, December 2010. *European Summary Report on CHP Support Schemes*. See also http://site.ge-energy.com/prod_serv/products/gas_turbines_cc/en/stag/experience.htm

By the early 2000s, it became clear that Dutch CHP was having difficulty surviving in the deregulated electricity market and under volatile natural gas prices. During off-peak hours, the price of electricity was set by low-cost coal and imported electricity, causing must-run CHP plants to run at a loss. CHP plants were also shut down at high-cost periods, resulting in a decline of cogeneration production. In order to maintain the energy savings achieved in the 1990s, in 2001 the Dutch government developed a new feed-in subsidy scheme to reinvigorate CHP and district heating.

The 2001 “Clean and Efficient” program was implemented as a set of policies seeking to achieve clean energy and climate goals. These policies include:

- **Feed-in Tariff (MEP/SDE)** – The MEP²⁸ was a kWh subsidy paid to domestic producers of electricity from renewable sources and CHP who fed-in to the national grid. The subsidy was a fixed premium paid on top of the price of wholesale electricity. The MEP was replaced with the SDE²⁹ in 2008. The SDE continues the feed-in tariff, however it differs from the MEP in that the subsidy amounts are corrected and vary depending on fossil fuel energy prices. The scheme is a “modified feed-in tariff,” a fixed subsidy with an option for a higher price per kWh if the electricity price goes above the subsidy ceiling. The scheme acts as a premium if the electricity price goes below the feed-in tariff. However, if the market electricity price is at or above the feed-in tariff price, no subsidy is received from the government.
- **Energy Tax Exemption** – Electricity-generating installations do not have to pay energy tax on their fuel consumption, provided that the electrical efficiency is higher than 30 percent and the electrical power is higher than 60 kW.
- **Interconnection Standards** – Technical specifications for interconnection across the Netherlands are codified by law. Connection tariffs depend on the capacity of the connection; connections up to 10 MVA are regulated. The connection charges are defined by the Grid Code and cover a range of different connection types. This approach guarantees non-discriminatory access to the network for a CHP unit.
- **Tax Incentives** – The Energy Investment Deduction is tax relief for investments in energy saving equipment and sustainable energy. Forty-four percent of the annual investment costs of CHP systems are deductible from profits over the calendar year in which the equipment was procured, subject to a maximum of EUR 107 million.
- **Public/Private Partnerships** – The Dutch CHP Agency established a platform for government, industry, and energy companies to work together to identify opportunities, advise on policy,

²⁸ <http://www.iea.org/textbase/pm/?mode=re&action=detail&id=998>

²⁹ <http://www.iea.org/textbase/pm/?mode=re&id=4031&action=detail>

and implement new projects. The Agency was set up to overcome the various regulatory and other barriers that hindered the development of CHP.

Market Effects

The following five figures show the growth of CHP in the Netherlands based on electrical and thermal output.

Figure 0-24: Growth of CHP Capacity in the Netherlands, 1998 – 2006

Source: Energy Research Center of the Netherlands

Figure 0-25: Growth of Thermal CHP in the Netherlands, 1982 – 1994

Source: IEA International CHP/DHC Collaborative: Country Scorecard, Netherlands

The majority of growth occurred from 1985 – 1998, a period in which CHP benefited from good spark spread and government support. After 1998, electricity market liberalization reduced electricity prices while natural gas prices became volatile, thereby significantly reducing the business case for CHP. In Figure 4-8, the substantial increase in electrical capacity in 2004 was caused by the opening of the Intergron plant in Rijnmond (825 MW) and the E.ON Lyondell unit on the Maasvlakte. Beginning in 1995, the Dutch government banned the construction of plants larger than 2 MW due to electrical over capacity. This ban was removed in 1998 and has not been in place since.

Beginning in 2001, the Netherlands experienced a boom in the greenhouse sector. Figure 4-8 shows the growth of CHP installed capacity in greenhouses.

Figure 0-26: Growth in Dutch CHP Capacity in the Greenhouse Sector

Source: IEA International CHP/DHC Collaborative: Country Scorecard, Netherlands

At the end of 2007, total installed agricultural CHP capacity was more than 2,500 MW, up from 1,000 MW in 2004. Since then, installation has slowed to approximately 30 MW per year. Beginning in 2004, agricultural CHP plants began taking advantage of their flexibility to respond to peak pricing. Greenhouses require low-temperature heat and CO₂ for crop fertilization. Demand for heat and high electricity prices often do not coincide. However, many greenhouses apply heat buffers, often large water tanks, which allow them to produce electricity during peak hours and provide the heat when required. In addition, greenhouses increasingly use electricity for lighting, which improves the economics of CHP, as on-site production of electricity is usually cheaper than purchasing electricity. The increase in CHP in greenhouses is primarily comprised of gas engines, which are well equipped to operate on volatile electricity markets.

In 2006, the total CHP capacity in the commercial sector was 2,897 MW, an increase of 34 percent compared with 2005. Figure 4-9 shows the distribution of CHP capacity in the commercial sector from 1998 – 2006.

Figure 0-27: Distribution of CHP in the Dutch Commercial Sector, 1998 - 2006³⁰

Source: Energy Research Center of the Netherlands

Most of the commercial sector CHP growth occurred in agriculture as reflected in Figure 4-9. Between 1998 and 2006, waste incineration CHP capacity doubled from 137 MW to 277 MW (~102 percent). The electrical capacities in other sectors have been relatively flat. Figure 0-28 shows that the natural gas reciprocating engines are by far the most common technology for CHP in the Netherlands.

³⁰ Energy Research Center of the Netherlands. Daniels. B.W. et. al. 2007. *High Efficiency Cogeneration in the Netherlands*.

Figure 0-28: CHP Capacity in the Netherlands by Technology Type, 1998 – 2006

Source: Energy Research Center of the Netherlands

Gas motors accounted for the majority of the increase in CHP from 2004 – 2006, primarily due to their near-exclusive use in the agricultural sector.

The effects of Dutch policy on CHP trends are difficult to isolate from market conditions. Growth has occurred since the Clean and Efficient Act of 2001, mostly from waste and agricultural sectors. The latter has likely grown due to the unique ability to profit under peak electricity tariffs. The former, which is run on carbon free biogas, is likely benefiting from the feed-in tariff.

Other European CHP Markets: Portugal, Denmark, and Finland

Portugal, Denmark, and Finland also provide illustrative case histories in CHP promotion.

Portugal

The Portuguese Cogeneration Law, passed in 2001, is an innovative feed-in tariff that provides monthly “true-up” for CHP plants that exported electricity. The government decided to support CHP because it was seen as an efficient mechanism for meeting greenhouse gas emissions reduction

targets established under the Kyoto Protocol. The Portuguese government set a goal of achieving 2,000 MW of installed CHP capacity by 2010. As of 2008, 1,200 MW was in operation.

The Portuguese feed-in tariff is based on the principle of avoided costs, which compares system costs of CHP to those of conventional generation through a centralized gas-fired CCGT power plant. The avoided costs include: avoided capital investment, avoided production costs, avoided cost of network losses, and avoided environmental (CO₂) costs. Tariffs are in effect for a period of 10 years and are indexed against the price of fuel (oil or gas) to reduce fuel price risks. Plants are allowed to export up to 100 percent of electricity to the grid. Eligible plants must achieve a minimum electricity equivalent efficiency (taking into account both the heat and electrical efficiency) to qualify for support. For natural gas, the unit must be greater than 55 percent efficient. For biomass, the unit must be greater than 45 percent efficient.

Since 2001, the share of CHP has grown, but has not made a significant impact on the national energy mix. The percent of the Portugal's electricity generated by CHP rose from 11 percent to 11.9 percent from 2004 – 2008. However, the country's primary barrier to further CHP growth is its lack of natural gas network. Portugal first received natural gas in 1997; potential CHP operators often must finance the construction of natural gas infrastructure. According to the IEA,³¹ biogas generation of any kind has been stagnant over the past decade. All growth in Portugal's generation is accounted for through natural gas and a small but growing contribution from geothermal and solar. However, there likely remains opportunity for CHP in the waste (biogas) sector, either in new installations or engine upgrades.

Denmark

By the early 1970s, Denmark was completely dependent on foreign oil. After the oil crisis of 1973-74, Danish policy makers established an energy policy with the goal of becoming energy independent.³² A national energy plan was developed, which included the 1979 Heat Law. National targets were established in order to increase cogeneration; considerable investment was made in a district heating infrastructure. Natural gas resources in the North Sea were developed and a natural gas grid constructed. To promote CHP, Denmark established a feed-in tariff and a grid operator purchase obligation for CHP electricity. A direct support scheme was also introduced in 1992 which subsidized generation at 1.5 €/kWh. Due to the rapid growth of CHP from these incentives, the

³¹ http://www.iea.org/stats/pdf_graphs/PTELEC.pdf

³² Energy consumption in Denmark has essentially been stagnant since 1972. Meanwhile, GDP has increased from \$22.6 billion to 310 billion during the same period. See: http://www.iea.org/stats/pdf_graphs/DKTFC.pdf and http://data.worldbank.org/indicator/NY.GDP.MKTP.CD?cid=GPD_29

support was lowered to 0.95€/ct/kWh. By 2004, 50 percent of Denmark's electricity was generated by CHP and 60 percent of heat was supplied by CHP district heating. The share of CHP has declined since then due to the increased contribution of wind to the Danish electrical grid. Today, the government has removed most support for CHP. All localized CHP above 5 MW are required to sell their electricity production at market prices. CHP below 5 MW are not required to sell into the grid; these units receive a subsidy for generation only during peak periods.

Finland

Finland is a unique example of a world leader in CHP, with high levels of development in district heating, industrial CHP, and use of biofuels, achieved without specific government support. In 2007, CHP produced 74 percent of the heat needed for district heating and generated 29 percent of the country's electricity supply. In a country with a cold climate and limited resources of energy, CHP has been the natural economic choice for many applications. Space heating is needed almost nine months a year and in winter, electricity for lighting is needed for a large part of the day. As a result, district heating produced with CHP is provided year-round to all buildings for domestic warm water and building heat.

The Finnish industrial sector is highly energy-intensive, accounting for 53 percent of total electricity demand. Given its suitability for energy-intensive applications, CHP accounts for almost 80 percent of industrial heat, with the forestry and the paper industry the largest consumers of energy in the industrial sector. The paper sector makes heavy use of forest waste to provide the heat necessary for paper production and often for heating nearby communities. Approximately 20 percent of the energy consumed in Finland is for the heating of buildings; about half of this demand is connected to district heating networks. However, over 80 percent of the energy consumed in larger towns and cities is connected to district heating, making Finnish cities – and Finland as a whole – among the highest users of efficient district heating with CHP in the world. There is little opportunity for commercial scale CHP in Finland.

While there is no specific government support for Finnish CHP, a few policies in place have had the effect of lowering barriers to CHP siting. In Finland, anyone conforming to the necessary safety and environmental standards can build a power plant without a license (excluding nuclear and hydro plants). Commercially viable projects have been able to move ahead promptly. This straightforward entry into the electricity market has been important in speeding up the development of large CHP schemes that may otherwise have taken a few years to gain approval. Moreover, the tax policies of Finland have driven the use of certain fuels in CHP. Finland was the first country to enact a carbon tax in 1990, based on the carbon content of fuels used in heat production. This tax is currently

€18.02/metric ton of CO₂. Natural gas receives a 50 percent tax rebate, while peat receives a complete exemption, thus incentivizing the use of renewable fuels and fuels with lower carbon content in CHP systems.

Due to the successful development of CHP to date there, there is not a substantial amount of remaining achievable potential for CHP in Finland. For example, in Helsinki, approximately 93 percent of the building volume is already served by a CHP district heating network. However, a recent study³³ showed potential growth of nearly 20 percent in the next 15 years, achievable if new simulative measures are enacted. Commercial district cooling applications of CHP are among the opportunities with growth potential in Finland.

Key Lessons Learned from the European CHP Experiences

European experiences have been varied with regard to the promotion of CHP applications. The governments that have established proactive policies to support CHP have had success so long as significant barriers, such as the lack of an extensive natural gas network or onerous permitting, are absent (discussed in each country section above).

Barriers to entry for CHP are similar to barriers in the U.S., with the exception that air quality emissions performance and permitting is not an issue in most parts of Europe. However, In the Netherlands the new 2010 legislation, BEMS³⁴, requires Selective Catalytic Reduction (SCR) for natural gas fired gas engines with more than 2,500 kW fuel input. This makes CHP costly in the Netherlands. Similar situations exist in other densely-populated regions, such as parts of Italy. The most common EU barriers to CHP growth are inadequate financial return on investment, difficulty with interconnection, high demand charges by the local utility, lack of awareness of the benefits of CHP, and difficulty apportioning GHG reduction credits due to the combination of heat and power energy in one unit.³⁵

³³ *The Potential of CHP and the Future of DHC in Finland*, Gaia Group Oy, 2007.

³⁴ <http://www.infomil.nl/english/subjects/air/combustion-plants/bems-sets-new>

³⁵ IEA/DHC Collaborative, 2009. *Cogeneration and District Energy: Sustainable Energies for Today and Tomorrow*.

The common characteristics of successful efforts to promote CHP are as follows:

Government Policy and Support

- **Interconnection Standards** – Grid connection enables CHP plants to sell any surplus electricity to the grid and import when the site need exceeds CHP output. Interconnection standards are intended to provide fair and clear rules for obtaining physical connection to the grid. They outline the procedures for the application process in a transparent way as well as standardize the technical requirements for connection. There are also grid access rights (e.g. Germany), where CHP generators are given priority access to the grid. The three common types of grid access rights are net metering, which allows for the flow of electricity to and from the customer meter, priority dispatch, and licensing exemptions that allow CHP operators to generate without a generator license (e.g. Italy).
- **Target Setting** – Several EU governments realized that CHP was a “no regrets” option for achieving policy goals. In the 1970s, Denmark promoted CHP as a path towards energy security, by implementing energy efficiency measures. Today, many EU countries are using CHP policy to achieve greenhouse emissions reductions. Successful governments set ambitious but achievable targets for the adoption of CHP, establishing policies to meet the targets. CHP has been seen as the best technology in the “medium-term” to support energy efficiency and emissions reductions, while other zero emissions technologies are perfected for the “long-term.”
- **Reducing Permitting Barriers** – Some countries have very low barriers for siting generation. For example Finland allows anyone to become a CHP generator through a streamlined permitting processes. Free or preferential access to the grid, fast permitting, and easy access to the grid without barriers like high voltage demands, are crucial for the success of CHP.
- **Outreach and Education** – Some European governments have been proactive in their outreach and education on the benefits of CHP. Germany and the Netherlands have been particularly persistent on outreach. However, the Netherlands’ CHP agency’s lobbying efforts been less concentrated and effective, as compared to coal and nuclear advocacy.

Fiscal Support

- **Feed-in Tariffs** – These are the most important policy mechanisms in Europe for incentivizing CHP. These are guaranteed bonus rates for electricity fed into the grid that serve to reduce the CHP investment payback period. According to the economic modeling of the CODE Project, a payback period of three years is required for significant CHP growth.³⁶ A critical component to meeting that threshold is a guaranteed tariff term period of 10 to 20 years that allows CHP investors to include that income stream in decision making. Tariffs are typically based on the wholesale price of electricity, plus either a bonus rate in a declining schedule (Germany), based on avoided generation and environmental costs (Portugal), or based on a market-derived tariff (the Netherlands). Rates can differ based on fuel in order to incentivize renewable energy. Germany's biogas tariff is a prime example. Some countries (Denmark, Germany after 2008) provide direct compensation for actual generation from CHP units regardless of how much is fed into the grid.
- **Green Certificate Schemes** – These are market-based mechanisms that also provide an additional income stream to CHP owners. Certificates are provided to CHP operators by the government based on the amount of CO₂ reduced as compared with separate generation of heat and power. Utilities are required to surrender a certain amount of green certificates to the government every year, based on the government's CO₂ reduction goals. This creates a market for utilities to buy the certificates from CHP operators. Biogas provides a significant amount of certificate revenue because it is considered carbon neutral. This is the primary mechanism in Belgium, and has been highly successful where barriers are not a factor (the Belgian Flanders region).
- **Tax Incentives** – Many countries provide tax incentives for capital investment in high efficiency CHP. It is common that governments allow CHP investors to write off 20 – 40 percent of investment costs from their operating profit. Operating costs are lowered for CHP plants in countries that exempt natural gas fuel from fuel taxes and carbon levies. Tax incentives and accelerated depreciation have been employed in the Netherlands, Italy, Belgium, and the United Kingdom.
- **Upfront Capital Support** – Grants and rebates for purchasing CHP equipment and accelerated depreciation can reduce the payback period to make CHP attractive to investors. The Netherlands, Italy, Spain, and Belgium have a history of providing grants for installed CHP capacity.

³⁶ CODE Project, December 2010. *European Summary Report on CHP Support Schemes*.

Commercial Analysis of European CHP Markets

Several studies by individual countries have estimated the market potential for CHP applications. The International Energy Agency's (IEA) CHP Collaborative has aggregated available market potential information, reflected in Figure 0-29.³⁷

Figure 0-29: Market Potential (Percent of Generation) for CHP in 2015 and 2030

Source: EIA

The EIA arrived at these CHP potential estimates by taking into account the heating and cooling demand in the industrial, commercial, and residential sectors and assuming continued adoption of pro-CHP policy regimes. Therefore, these forecasts could be interpreted as optimistic because the EIA assumes greater adoption of pro CHP policies. Figure 0-29 shows the expected rise in CHP capacity in the G13. Countries are expected to see a small increase until 2015, with a correspondingly larger growth by 2030 as policies are enacted and begin to be widely implemented. As a whole, the share of CHP rises from 11% of electricity generation today to 15 percent in 2015 and 24 percent in 2030 under ideal CHP policies.

The CODE Project estimated that as of 2007, there was nearly 100 GW of installed cogeneration capacity in 27 member states. They also project 122 GW of additional economic potential in 23 of

³⁷ IEA, 2008. *Combined Heat and Power: Evaluating the Benefits of Greater Global Investment*.

the 27 Member States by 2020. The remaining four states did not have enough data for a potential estimate. The CODE Project reviewed the CHP potential reports of EU countries that submitted data by the end of 2009. Figure 0-30 shows the self-reported economic market potentials of CHP in Europe by country.

Figure 0-30: Forecasted CHP Capacity by EU Country, 2020

Source: CODE Project, 2010

The EIA's forecast of CHP capacity would provide by 2020 a total contribution to Europe's energy flows of 455 TWh of electrical energy and at least 1,000 TWh of useful heat supply from an estimated 122 GWe of generating capacity.

The evaluation process for determining economic potential varies widely across reports, and the following observations apply:

- The judgment as to what is economic or not is heavily dependent on the member state assumptions and on the assumed rate of return. For example, the UK report identifies that an economic rate of return for a commercial enterprise is 15 percent, while a public sector return on investment is 9 percent. Under these criteria, all investments in district heating are categorized as uneconomic. By contrast, Germany based its report on a feasibility analysis

using an annual interest rate of 8 percent in the commercial sector and 5 percent in the public sector.

- The economic effectiveness of the cogeneration potential for small scale (and micro) units in the services and household sectors remains uneconomic for broader penetration.
- According to the CODE Project analysis, the large reported German CHP potential is due to 1) a long term energy strategy based on renewables and energy efficiency, linked to a strong commitment to meeting Kyoto goals, and 2) a tradition of CHP utilization in both industrial process and district heating schemes. This produces a strong technical, social, and economic understanding of the potential of cogeneration to improve energy efficiency and allows a robust assessment of the CHP potential.

Additional broader conclusions include:³⁸

- There is significant industrial potential for CHP in Europe. The larger economies comprise approximately 50 percent of the EU CHP potential.
- In the southern parts of Europe, the industrial and commercial sector CHP potential have been pursued over the district heating potential.
- Significant potential exists in new member states, particularly for refurbishment of district heating schemes and their upgrade to include modern cogeneration where previously only heat was distributed. This is universally the case where a large district heating infrastructure already exists.
- In many new member states, the highest share of CHP economic potential has been linked to the modernization and upgrade of cogeneration units in district heating systems, with the replacement of existing steam turbines by combined cycle units running on natural gas.

Target Markets in Specific Countries

The following is a summary of the current landscape and market opportunities in specific European countries.

Belgium

Flanders, which has had the most success stimulating CHP through their white certificate scheme and well developed natural gas network, remains the most promising market for growth of CHP in

³⁸ CODE Project, 2009. *Preliminary analysis of the reports on cogeneration potential in the EU Member States.*

Belgium. The most recent publicly available CHP market evaluation in Flanders reported 2005 data.³⁹ In that year, horticulture was the most important sector, with a total installed capacity of 74.4 MW (46 percent); the installed capacity in industry was 60.9 MW (38 percent). The shares taken by waste-processing, hospitals and rest homes, sport/recreation/culture and offices/residential were 7 percent, 6 percent, 2 percent, and 1 percent, respectively. Natural gas is the predominant fuel in all sectors, with the exception of waste-processing, where biogas is dominant.

For example, the Lavrijsen plant in Helchteren uses biogas to produce electricity and heat for the nearby resort "Molenheide."⁴⁰ Belgium supports CHP applications with its CHP (white) and biogas (green) certificates that give extra revenue for the owner of the biogas plant. Lavrijsen is a farmer, who uses his agricultural waste for his biogas installation and buys additional waste to feed the digester. Lavrijsen started with a dual fuel engine (biodiesel and biogas) and a Dresser-Waukesha APG1000 biogas engine. Recently, he added a second APG1000 biogas engine to make full use of his digester.

Brussels has little heavy industry, thus the growth of CHP has occurred primarily in office buildings and hospitals. Most installations are gas engines that run on pipeline gas with a few that run on biofuels. Access to the natural gas network is less extensive in the southern part of Belgium than in the North. This constraint limits the potential for developing natural gas cogeneration in Wallonia.

Italy

Today, 25 percent of Italy's electricity is supplied by cogeneration. Seventy-five percent of installed CHP power is from units under 10 MW. Thirty percent of Italian CHP facilities generate power less than 1 MW while micro-CHP (power less than 50 kW) accounts for only 1 percent of installed units. There are also examples of large facilities (up to 300-400 MW), which are mainly located inside large industrial sites. There are no large district heating networks, which allows room for CHP to provide district and building heat and hot water.

Currently, Italian law provides incentives for electricity produced using high-efficiency cogeneration. The main incentives include:

- An exemption from the obligation to purchase green certificates (an obligation that generally is applicable to electricity produced by nonrenewable resources).

³⁹ VITO, 2007. *Cogeneration report for Flanders - The situation in 2005*.

⁴⁰ <http://www.molenheide.be/en>

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- The right to dispatch priority, following electricity that is produced by strictly renewable resources.
 - Tax breaks on natural gas used for cogeneration.
 - The option of obtaining energy efficiency certificates which may be traded.
 - Green certificates for high-efficiency CHP facilities connected to district heating networks that satisfy certain requirements regarding plant commissioning.

According to the Italian CHP Progress Report⁴¹, the best opportunities for engines in the 500 kW – 5 MW range include:

- Retail (average size 0.7 MW)
- Education (average size 1.0 MW)
- Hospitals (average size 1.2 MW)
- Textile Industries (average size 1.3 MW)
- Ceramics Industries (average size 3.8 MW)
- Tanneries (average size 4.0 MW)

Germany

The German chemical and mining industries are the main users of CHP. The German market for industrial CHP has been quiet in recent years since the CHP law did not subsidize CHP larger than 2 MW. The new 2009 CHP law does subsidize industrial CHP larger than 2 MW. Commercial CHP is a relatively minor segment in the German market because many suitable office and public buildings are in areas already served by municipal district heating schemes. However, CHP is also increasingly being applied in buildings like hospitals and hotels. Support through the 2009 CHP law is likely to ensure that this will continue, and perhaps accelerate.

District heating CHP is widely applied in Germany, primarily by municipalities. Many municipalities have recently started to expand their CHP and district heating investment, driven by strong government support and the attractive economic performance of such schemes. The four major utilities also have significant CHP assets in district heating, although large power plants remain their core business. E.ON and Vattenfall have developed CHP plants by connecting their conventional

⁴¹ Ministry of Economic Development, 2009. *Report on Progress Made to Increase the Share of High Efficiency Cogeneration.*

power plants to district heating networks, while industrial applications dominate the portfolios of RWE and EnBW.

Organic Rankine Cycle (ORC) is a promising technology, but generally the investment costs are still too high. For instance, the 500 kW ORC at the Kempen District Heating plant will take the heat from three gas engine exhausts to be cooled by the district heating water, improving electric efficiency of the plant from 42 percent to 44 percent. No heat is wasted as the return heat is fed into the district heating system. Nevertheless, this is feasible only because of a subsidy. This subsidy is not a general subsidy for ORC, but a special "demonstration" subsidy of 2 Eurocents per kWh for "new" technologies like ORC. The 2 Eurocents incentive for innovative technology is only paid for the electricity produced by the ORC. However, most biogas sites still do not use ORC.

The number of biogas CHP plants in Germany has grown rapidly since 2000. In 2007, over 3,700 units were operating, representing 1,271 MW of capacity. Figure 4-13 demonstrates the growth in biogas capacity.

Figure 0-31: Growth in German Biogas Capacity, 2000 - 2007

Source: German biogas association (www.biogas.org)

The main sources of biogas are landfills, sewage gas, agricultural waste, and manure. Landfill sources are showing saturation, however the agricultural biogas sector has been growing rapidly. Most biogas systems are, due to the incentives in place for engines sized around 500 kW (net) and are predominately gas engines. The potential for further growth is substantial. The German government projects installed capacity to reach 2,768 MW by 2020 at an estimated 30 000 sites.⁴² The Renewable Energy law has been the driving factor for the development of the biogas CHP sector in Germany. However, agricultural biogas in Germany can only sustain with subsidies. The German government has argued that in time, fuel prices will rise to a level that will make agricultural biogas viable.

An important development in the German market is rising natural gas and electricity prices. The 2011 nuclear disaster in Fukushima, Japan prompted the Merkel government to promise the retirement of Germany's nuclear power plants by 2022.⁴³ An increased reliance on natural gas for power generation increases Germany's reliance on Russian natural gas supplies. This may be a risk for CHP operators if natural gas prices spike, although this could be tempered by the rise in grid

⁴² IEA CHP/DHC Collaborative: Country Scorecard, Germany.

⁴³ <http://www.finance-ol.com/2011/05/germany-announced-retirement-of-nuclear-power-to-close-all-nuclear-power-plants-by-2022/>

electricity prices. The longer-term opportunity may be that as Germany takes nuclear plants off-line, CHP could have an important role in replacing that resource.

The Netherlands

Cogeneration has been a major supplier of electricity in the Netherlands, currently accounting for about 35 percent of total installed production capacity. As Figure 0-32 indicates, industry accounts for about 50 percent of CHP capacity. District heating accounts for another 25 percent of the CHP capacity. 12 percent of CHP is found in agricultural greenhouses. The remaining capacity exists in commercial and residential installations. The majority of Dutch CHP plants run on natural gas.

Figure 0-32: CHP Installed Capacity by Sector in the Netherlands

Source: Energy Research Center of the Netherlands

The potential for CHP growth in the Netherlands market appears to be limited. As in many other European countries, deregulation of the energy markets has kept electricity prices low and thus has deteriorated the position of CHP in the Netherlands. After wholesale market electricity and gas prices began being set by the market rather than regulators, fuel price fluctuations produced more spark spread volatility. Under current conditions, during peak hours, gas-fired facilities are optimizing prices since CHP can produce electricity fairly competitively. However, during off-peak hours, coal-fired facilities experience electricity at much lower marginal cost. CHP facilities that are classified as “must-run” are required to sell their power at prices often when the market prices are low to cover the operational costs. This is the primary reason that CHP growth has stagnated since the late 1990s. Significant growth occurred in the waste and greenhouse sectors from 2004 – 2007, but has since slowed due to weak policy incentives and potentially market saturation. As discussed in

Section 4.1.5, the SDE feed-in tariff does not provide substantial incentive for new cogeneration or the replacement of older cogeneration. This market should be monitored for new policy incentives currently under consideration.

The Energy Research Center of the Netherlands⁴⁴ projects limited achievable potential of cogeneration in the industrial sector because CHP usually requires far-reaching integration of cogeneration into industrial processes. Industrial producers have voiced strong reservations about cogeneration in such cases, because of the increased risk on process failures. Greenhouses continue to be an important sector for CHP, although the growth has slowed significantly since the 2007. The potential in the services sectors are uncertain, as there are lower cost and risk alternatives for cogeneration. In new office building construction for example, the application of heat pumps combined with heat and cold storage in aquifers is becoming a standard technology application.

In the commercial sector, space heating followed by hot tap water drives heat demand. Many buildings, especially offices, have cooling demand for air-conditioning. Heat demand appears to have stagnated in recent years, and is expected to decline in the near future, due to the gradual replacement of older buildings by new ones. Heat demand has a strong seasonal pattern, and especially in new, well-insulated buildings, heat demand is concentrated in relatively few hours, which is not very favorable for the profitable operation of cogeneration.

Generally, only the larger buildings or concentrations of buildings apply cogeneration, such as hospitals and universities. Micro-turbines and fuel cells may play a role as an alternative to internal combustion engines in the future, however, recent technological improvements (efficiency and emissions) for gas engines have for now staved-off larger penetration of fuel cells and micro-turbines. An alternative to on site cogeneration is heat distribution, although in the Netherlands, application of district heating is not widespread. For new buildings, strict efficiency codes deteriorate the cost-effectiveness of district heating. Installing district heating in existing infrastructure is cost prohibitive, therefore, the potential for cogeneration in district heating is limited.

Russia

Russia uses CHP generation extensively, where it accounts for about one- third of installed electricity generating capacity. Russian industry is highly energy-intensive. In 2007, the industrial sector accounted for 50 percent of total electricity demand. Given its suitability for energy intensive applications, over half of Russia's 500 CHP plants are based within the industrial sector. Russia also

⁴⁴ Energy Research Center of the Netherlands. Daniels. B.W. et. al. 2007. *High Efficiency Cogeneration in the Netherlands*.

has the largest and oldest district heating system in the world. Low investment and inadequate maintenance during the 1990s has left the district heat network in substantial disrepair, with an estimated 60 percent of the network in need of major repair or replacement. Raising the investments needed to replace, repair and maintain this immense network is the key challenge facing Russia's district heating system.

Since the early 2000s there has been increasing momentum in refurbishing existing boiler houses with gas turbines or smaller scale industrial CHP units (capacity less than 25 MW). Most retrofitting to date has used foreign technology. As of March 2007, about 120 of these units were operating across Russia.

CHP in Russia suffers from a lack of government policy as well as a lack of qualified engineers to operate CHP systems. Heat tariffs are kept artificially low for political reasons, which have had the effect of reducing the attractiveness of CHP applications. Macro-scale barriers which continue to hamper investment include a lack of contract enforcement and an unstable investment environment. Specific barriers include: low energy prices, monopolistic structures, and lack of consumer control. Due to the lack of metering equipment in most of Russia's older building stock, it is difficult to assess how much heat is consumed.

Poland

In 2008, nearly 17 percent of the total electricity production in Poland came from CHP. The biggest share among cogeneration systems was represented by municipally-owned CHP plants with 5,400 MW of installed capacity.

The 1997 Energy Law⁴⁵ was adopted to establish a competitive electric market and regulatory framework. CHP is promoted by requiring power distribution companies to purchase all electricity from CHP plants that achieve an average annual efficiency of over 65 percent. In 2007, the law was updated to institute a "green certificate" scheme. CHP systems larger than 1 MW now receive certificates worth 4.8 €/MWh generated (not just exported). CHP systems smaller than 1 MW receive subsidies as well, although they are variable and revised on an annual basis. This CHP support system will remain in effect until March 2013.

The most promising and immediate market for cogeneration is in existing district heat systems that are in need of refurbishment. About 25 – 30 percent of Poland's district heat is derived from low efficiency heat-only plants. The increasing availability of natural gas also provides a good

⁴⁵ <http://www.ure.gov.pl/download.php?s=2&id=2>

opportunity for fuel switching in industrial cogeneration plants. A firm of Polish consultants recently estimated that, between now and 2020, the annual market for industrial cogeneration plant would be approximately 175 MW.⁴⁶ The most promising applications for 500 kW – 5 MW sized CHP systems are waste water plants and landfill sites, but there are no publicly-available forecast estimates for specific market potential available.

The primary barrier to widespread adoption of CHP in Poland is low electricity prices due to a heavy reliance on coal based resources. Interconnection requirements, which can involve lengthy negotiations with the grid operator, are also a significant barrier to CHP growth in Poland. Administrative authorizations historically can also take significant time.

United Kingdom

According to the 2008 Digest of UK Energy Statistics (DUKES)⁴⁷, in 2007 high efficiency CHP capacity was at 5,474 MW, representing about 7 percent of the total UK electricity demand. Natural gas is the predominant fuel, with 71 percent of market share. Renewables (biogas) make up only 4 percent of CHP fuels. The remainder of the fuels are refinery gasses (6 percent), coal (4 percent), blast furnace gas (2 percent) fuel oil (2percent), and “other fuels” (11 percent).

Figure 0-33 below shows the growth of CHP in the UK from 1996 – 2007. In terms of electrical capacity by size of CHP application, , schemes larger than 10 MWe represent over 83 per cent of the total electrical capacity of CHP schemes. However, in terms of number of schemes, the largest share (81 percent) is in schemes less than 1 MW. Schemes of 1 MWe or larger make up approximately 19 percent of the total number of CHP schemes.

Figure 0-33: Growth in UK CHP Capacity and Installations, 1996 - 2009

⁴⁶ Export Energy Efficiency Council, *The Market for Energy Efficiency in Poland*
<http://www.ecee.org/pubs/poland.htm>

⁴⁷ The International CHP/DHC Collaborative. *Country Scorecard, United Kingdom*

Source: Digest of United Kingdom Energy Statistics (DUKES)

CHP installation has been flat or negative since 2000, with a spike in activity in 2004. Under current market conditions, a number of operators have chosen to mothball their CHP schemes rather than continue to operate. At the end of 2009, there were 100 mothballed CHP schemes with a good quality capacity of 91 MW.

Figure 0-34 shows that oil, gas, and chemicals account for 66 percent of the CHP generating capacity. Other sectors include: agriculture, district heating, leisure, landfill and incineration. The market best served by the Dresser-Waukesha 1.1 MW engine, comprises 5 percent of the UK market.

Figure 0-34: UK CHP Electrical Capacity by Sector in 2009

(1) Other sectors include: agriculture, community heating, leisure, landfills, and incineration (2) Other industries include: textiles, clothing and footwear, and sewage treatment

Source: Digest of United Kingdom Energy Statistics (DUKES)

Table 0-15 shows the distribution of CHP schemes in the UK commercial sector, public sector, and residential buildings.

Table 0-15: Number and Capacity of UK CHP Schemes by Sector, 2009

	Number of Schemes	Electrical Capacity (MWe)	Heat Capacity (MWth)
Leisure	395	50.7	52.8
Hotels	244	34.8	40.9
Health	180	121.1	164.6
Residential	39	27.8	59.8
Universities	42	50.4	83.8
Offices	20	16.7	12
Education	18	10.2	17.7
Government	16	15.8	18.4
Retail	44	10.2	3.4
Other	3	10.5	18.7
Total	1,001	348.3	472.1

Source: Digest of United Kingdom Energy Statistics (DUKES)

The healthcare sector maintains the largest proportion of capacity. Leisure and hotels account for nearly two-thirds of the total number of CHP schemes but only about 25 per cent of the electrical capacity.

There are a range of support measures to incentivize the growth of “good quality”⁴⁸ CHP in the UK. These include:

- Exemption from the Climate Change Levy (CCL) of all fuel inputs to, and electricity outputs from, good quality CHP.
- Eligibility for enhanced capital allowances (ECAs) for good quality CHP plant and machinery.
- Favorable allocations of carbon allowances under Phase II of the EU Emissions Trading Scheme (EU ETS).
- Business rate exemptions for CHP power generation plant and machinery.
- Extension of the eligibility for Renewable Obligation Certificates (ROCs) to energy from waste plants that utilize CHP.

⁴⁸ Defined as a 10 percent improvement over the separate generation of electricity and heat. See <http://www.decc.gov.uk/assets/decc/Statistics/publications/dukes/312-dukes-2010-ch6.pdf>

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- Increased support under the Renewables Obligation, with two Renewable Obligation Certificates (ROCs) allocated to the good quality electricity output of CHP fueled by biomass.

The UK government does not directly subsidize CHP generation. The fuel tax exemption is a value of about € 0.002/kWh. Beginning in April 2009 under the UK Renewables Obligation (a renewable portfolio standard), electricity generated by high efficiency CHP fueled by biomass are eligible for additional ROCs for each MWh of renewable electricity generated. Utilities can purchase these certificates to meet their renewables requirements. In addition, grants for capital purchases of biomass-fueled heat-only or CHP equipment are available through the bio-energy capital grants scheme run by the UK Department for Environment, Food and rural Affairs ([Defra](#)). Developers of high efficiency CHP are allowed to write off the full cost of their investment against their taxable profits during the period in which they make the investment. However, ECAs are not available to utility developers.

In April 2010, the Carbon Reduction Commitment (CRC) came into effect. The CRC is a mandatory emissions trading scheme that covers large, non-energy intensive businesses not covered under other policy measures like Climate Change Agreements (CCAs) and the EU ETS. Under the CRC, eligible organizations are required to purchase allowances to cover the CO₂ emissions from all fixed-point energy sources. This means that allowances must be purchased to cover the use of electricity, gas, and all other fuel types such as Liquefied Petroleum Gas (LPG) and diesel. However, under CRC heat is zero-rated, meaning that allowances will not have to be purchased by a site to cover any imported heat. It is expected that this treatment will stimulate a growth in the heat market, and this will in turn incentivize the use of CHP. Starting in 2013, the first capped phase will commence and allowances will be sold to participants through an auction.

However, significant barriers to CHP still exist in the UK. Spark spreads have historically been insufficient to make CHP attractive. Price volatility of natural gas has made CHP appear to be a risky investment. Carbon prices have been unstable, and the allocation of carbon allowances to CHP has been politically uncertain. While the exemption from the Climate Change Levy has helped lower these financial and regulatory barriers to some extent, this market still cannot be characterized as highly attractive for CHP investment. There is no reason to believe that the flat and negative growth trend will reverse in the future.

IESG Data Analysis

We reviewed engine manufacturer self-reported sales data to the International Engine Statistics Group (IESG). An important note when interpreting this data: some engine manufacturers report

based on the country of end use shipment and some report where it was manufactured; however, the analysis does provide data points to assess the status of the CHP market is in Europe.

Market Share by Engine Size

The following charts depict the IESG data in terms of engine size distribution and market share within the major CHP purchasing countries (France, Belgium, the Netherlands, Germany, Italy, UK, Denmark, Greece, Portugal, Spain, Norway, Sweden, Finland, Poland, Czech Republic, and Russia). Market share estimates were derived by country base on the number of CHP engine sales over the period 2005 – 2010.

Figure 0-35: CHP Market Share – 1.0 MW - 1.5 MW Systems (Selected Countries)

Source: International Engine Statistics Group (IESG). Note: because this data is self-reported, see the data caveat at the beginning of Section 4.2.2. This data does not necessarily reflect installations; but rather, sales and bookings that are self-reported.

Figure 0-36: CHP Market Share - 1.5 MW - 2.0 MW Systems (Selected Countries)

Source: International Engine Statistics Group (IESG). Note: because this data is self-reported, see the data caveat at the beginning of Section 4.2.2. This data does not necessarily reflect installations; but rather, sales and bookings that are self-reported.

Figure 0-37: CHP Market Share - 2.0 MW - 2.5 MW Systems (Selected Countries)

Source: International Engine Statistics Group (IESG). Note: because this data is self-reported, see the data caveat at the beginning of Section 4.2.2. This data does not necessarily reflect installations; but rather, sales and bookings that are self-reported.

Figure 0-38: CHP Market Share - 2.5 MW - 3.0 MW Systems (Selected Countries)

Source: International Engine Statistics Group (IESG). Note: because this data is self-reported, see the data caveat at the beginning of Section 4.2.2. This data does not necessarily reflect installations; but rather, sales and bookings that are self-reported.

The IESG sales data demonstrates that the largest markets for CHP systems in the 1 - 3 MW range, which would be served by Dresser-Waukesha's ARES engine, vary widely depending on size category. However, the common major markets include:

- The Netherlands
- Germany
- UK
- Italy
- Russia

Spain also shows significant sales, especially in the 2.5 – 3.0 MW range. Belgium, despite the favorable political support, remains fundamentally a small market.

Specific Country Sales History by Size

Based on market share, we leveraged the IESG data to plot the size distribution of CHP units sold by country. Overall, sales have declined dramatically since 2007; however this is likely due to the global economic slowdown rather than specific CHP-only market factors.

Germany

Key Points:

- The 501 – 750 kW CHP unit market is dominant.
- CHP sales peaked in 2006, 2007 and have declined significantly since.

Belgium

Key Points:

- The primary market is CHP systems in the 1.0 – 1.5 MW range.
- Sales have declined significantly from the peak in 2007 (2008 peak for 2.0 – 2.5 MW systems).

The Netherlands

Key Points:

- The primary market is CHP systems in the 1.0 – 2.5 MW range.
- Sales peaked in 2006/2007 and have since declined significantly since.

Italy

Key Points:

- The primary market is CHP systems in the 1.0 – 2.5 MW range.
- Sales peaked in 2006/2007 and have since declined significantly since.

United Kingdom

Key Points:

- The CHP market is concentrated in systems ranging from 1.0 – 2.0 MW. There is very little market in any other CHP system sizes.
- There was a dramatic drop in sales in 2009/2010.

Russia

Key Points:

- There has been a bimodal distribution between 1.0 – 1.5 MW and 2.5 – 5.0 MW CHP system size classes.
- There has been a decrease in all CHP system size classes except for 2.5 – 5.0 MW range.

Spain

Key Points:

- There has been a bimodal distribution between 1.0 – 1.5 MW and 2.5 – 5.0 MW CHP system size classes.
- There has been a decrease in all size CHP system classes except for 2.5 – 5.0 MW range.

Distribution of Total EU CHP Sales from, 2005 – 2010

Figure 0-39 compares the five year total sales by CHP system size category in each of the IESG-analyzed countries.

Figure 0-39: 5-Year Sales Totals by Country and Size Class

Summary of European CHP Market Opportunities

Country	Government Support	Attractive Markets & Challenges
Most Attractive Markets		
Italy	Minimal government support for CHP; natural gas for CHP is tax free.	Light industry. IESG data shows positive sales.
Germany	Strong government support. Generation subsidy for CHP electricity; significant bonus for biogas CHP.	Largest economy in Europe. Good opportunities in district heating, industry, agriculture, landfills, wastewater treatment, hospitals. Biogas is extremely attractive, especially the 500 kW market segment. Transition away from nuclear may benefit CHP.
UK	CHP is exempt from the Climate Change Levy; tax write-off of capital investment in CHP.	IESG data shows strong sales in the UK in 2006/2007. However, poor spark spread and little government promotion of CHP poses challenges for the UK market. Recent sales have been anemic.
Belgium	Strong government support, especially in Flanders; green certificate scheme incentivizes lower carbon energy sources such as biogas.	Flanders (northern Belgium) is the most attractive market due to extensive natural gas network and strong incentives. Agriculture (greenhouses), industry, hospitals and office buildings are key markets. Demand for hot water is a key driver in buildings. However, Belgium is fundamentally a small market and will not likely drive significant CHP sales.
The Netherlands	Feed-in tariff.	The greenhouse sector, which can generate electricity during peak pricing periods and store heat for agricultural use, remains the best opportunity. However, low electricity prices have dampened the markets for CHP.
Spain	Feed-in tariff.	Strong historical sales reported from IESG. Spain's sovereign debt crisis is a risk to CHP support.
Russia	Limited government involvement in CHP.	Despite the great need for district heat and industrial boiler upgrades, Russia has a challenging business environment. However, IESG data shows strong sales in Russia.

Country	Government Support	Attractive Markets & Challenges
Less Attractive Markets		
Denmark	Little government support due to extremely high penetration of CHP.	Some district heating plants may need upgrades or replaced. Low growth expected.
Finland	Little government support due to extremely high penetration of CHP.	Some district heating plants may need upgrades. Low growth expected.
Portugal	Feed-in tariff.	Lack of natural gas network is a significant barrier. Potentially more growth in the future as natural gas network expands.
Poland	Green certificate scheme and CHP purchase obligation.	Modernization of district heating plants, industry, water treatment, and landfills. Poor spark spread and regulatory barriers make CHP investment difficult.

Recommendations to the U.S. Department of Energy

Objective and Approach

As part of this analysis, Dresser-Waukesha was tasked with developing a set of recommendations to the U.S. Department of Energy (DOE) to suggest approaches to increase the adoption of CHP in the U.S.

In order to develop DOE recommendations to meet this objective we:

- Reviewed DOE's current CHP initiatives to date;
- Reviewed salient recommendations from the Voice of the Customer (VOC) interview feedback assembled;
- Assessed the key CHP barriers in U.S. markets and strategies to overcome them going forward (Section 3 of this report); and
- Distilled potential "lessons learned" from the European market experiences with CHP.

Overview of DOE's CHP Efforts to Date

Background

Within DOE's Office of Energy Efficiency and Renewable Energy (EERE), the Industrial Technologies Program (ITP)⁴⁹ is responsible for "improving national energy security, climate, environment, and economic competitiveness by transforming the way U.S. industry uses energy." Combined heat and power (CHP), also known as cogeneration, systems are among the most promising energy efficient technologies supported by ITP.

According to the ITP, CHP holds great promise for decreasing energy consumption and carbon dioxide emissions in the U.S., and it is one of the few options in the portfolio of energy alternatives that combine environmental effectiveness with economic viability and improved competitiveness. Nationally, CHP system capacity currently is 85 GW, nearly 9 percent of total U.S. electricity generating capacity (see Section 3 of this report).

DOE CHP Initiatives Overview

In order to support the CHP objectives identified, the DOE has:

⁴⁹ <http://www1.eere.energy.gov/industry/distributedenergy/>

- Awarded grants to demonstrate and validate CHP technologies;
- Awarded research and development funding and support to further develop small-scale cogeneration applications (Dresser-Waukesha was a 2010 recipient of such funding, which initiated the analysis in this report);
- Facilitated education and outreach through ongoing conferences and workshops among stakeholders and partners, such as state and local governments, utilities, and retailers;
- Promoted CHP, waste heat recovery, and other clean energy technologies through its Clean Energy Application Centers.
- Supported specific research (technological, economic, policy) regarding CHP applications through its National Labs.

Dresser-Waukesha's Recommendations to DOE

The following recommendations are offered as recommendations to the DOE to build-upon its current efforts to transform the U.S. energy markets, leveraging CHP as an important part of that solution. However, many of the barriers to achieving the 20 percent CHP market potential that the DOE has observed as a target⁵⁰ in the U.S. are driven by state policies (interconnection, permitting, renewable mandates) and utility variations in rates and tariffs (feed-in tariffs, setting demand charges, standby rates). As a result, we recommend the following for DOE to enhance its current initiatives to further promote CHP in the U.S.:

⁵⁰ <http://info.ornl.gov/sites/publications/files/Pub13655.pdf>

Recommendation: Develop a Specific “Roadmap” to Connect DOE’s CHP “Technical Potential” Estimates to Meet CHP Targets

In 2008, DOE’s reported the objective of meeting a target of achieving 20 percent of U.S. electricity generation capacity from CHP in the U.S.,⁵¹ or an increase from 85 GW currently to ~240 GW over the next twenty years.

The DOE has estimated the technical CHP potential by state which could be leveraged to achieve this target, and has funded a number of projects and education /outreach initiatives to tap this potential. However, we recommend the DOE develop a roadmap that explicitly ties the strategies to reach the targeted potential growth over the 20-year timeline the DOE has charted. Such a roadmap could include an annual summary of efforts to date, and indicate the targeted CHP segments instrumental in achieving CHP growth. Moreover, it would allow stakeholders in the industry to have a clearer vision of “how we get there” and allow the DOE to track progress-to-date, as well as refine programs, funding, and education initiatives along the way.

Recommendation: Explore Establishing CHP Minimum Efficiency Levels

Emissions equality has been a hurdle for reciprocating engines. Addressing Best Available Control Technology (BACT) should be addressed to allow reciprocating engines to be considered clean, efficient devices.

With CHP systems, there are two efficiencies, electrical and thermal. As the same fuel input drives both the electrical output and thermal output, typically one of the efficiencies can only be maximized at the expense of another. Knowing that a CHP system will typically average approximately 75-85 percent system efficiency, how the thermal and electrical efficiencies are balanced often will depend on the intended use and target market. The facility type, load profile, thermal usage, and retail tariffs will all have an impact on the efficiency requirements.

However, there is not a publicly-reported forecast of the level (or range) of targeted efficiency on any given CHP application or a requirement that systems meet a minimum level. As CHP technologies are improved and enhanced, the product designs from various manufacturers may achieve various electrical and thermal efficiencies.

DOE could also consider establishing specific CHP application subsidies that render an overall targeted minimal thermal efficiency (example - 80 percent) and have this consistently applied across all states.

DOE could consider a collaborative of manufacturers, engineers, and end users to explore setting minimum CHP efficiency requirements by facility size (the percentages to be negotiated). An

⁵¹ http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf

incentive scheme based on meeting or exceeding those efficiency thresholds could be explored. The DOE could examine the design and economic impacts (savings, greater energy efficiency) of a CHP efficiency incentive approach (e.g. tying tax credits to meeting or exceeding efficiency levels). This approach may be a way to incentivize further CHP technology improvements, which can then be tied to a range of benefits.

Recommendation: Investigate Establishing CHP Certificates

Currently, U.S. states have a varied approach to setting minimum energy efficiency and renewable portfolio requirements. To date, ten states include some definition of CHP or waste heat recovery as an eligible generation source for load serving entities to meet the state's RPS. Since there is not currently a National Renewable Energy Standard (although it has been proposed and debated in Congress), DOE may consider establishing a CHP certificate program (similar to Renewable Energy Certificates).

Under this approach, each utility with a CHP carve-out in its RPS law would be required to deliver CHP certificates against the predetermined quota, similar to the approach undertaken in Massachusetts under alternative RPS compliance eligibility for CHP systems. High efficiency CHP operators could then apply to the state regulators for CHP certificates. The certificates could then be traded in a CHP certificate market where they are bought by the utilities seeking to meet their compliance obligation. One CHP certificate could be defined as the equivalent of one MWh of primary energy savings delivered through high efficiency.

This approach is also in place in Belgium and has been very successful in promoting the development of CHP applications. However, the challenge in the U.S. is that each state has jurisdiction to establish its RPS and determine individually what resources are considered "eligible." This creates some CHP credit trading limitations from a jurisdictional standpoint. However, exploring this option as a way to help states meet their overall energy efficiency requirements may be ripe for DOE platform to develop.

Recommendation: Investigate Advocacy of Generation Bonuses for CHP Systems

An important “lesson learned” from European countries with high CHP penetration (e.g., Germany, the Netherlands) is that for countries where feed-in tariffs are in place, they reduce the risk of CHP equipment investment by facilitating a cost offset that can be measured and included in ROI calculations. However, in the U.S., state utility commissions have jurisdiction over how utilities set rates and develop electricity and gas retail tariffs.

The DOE could consider directing one of its National Labs to undertake an analysis of the economic implications of feed-in tariffs, net metering, and standby tariffs on CHP installations and operations. Because the economics of CHP systems vary substantially across utilities due to the differences in how these rate issues are implemented, an assessment across U.S. markets would be a powerful cross-market investigation. The results could be leveraged for targeted advocacy that could point to these findings, and include customized rate recommendations by market to maximize the ability of a utility’s customers to operate CHP systems efficiently under a range of electricity and gas rate designs.

Recommendation: Review Allowing CHP Participation in ISO Markets

Recognizing the Distributed Generation nature of CHP as a generation asset, the DOE could consider allowing end use customers who self-optimize their loads through CHP, microgrids, and other onsite generation to be load balancing and participating in the ISO markets. This would entail a review of the variations in ISO/RTO market rules, and a consideration of where this participation may be beneficial to both customers and system operators.

Recommendation: Review and Advocate Regionally-Consistent CHP Interconnection Policies

On a state-by-state basis, there is a wide degree of variety and disparity in standards, policies, and requirements for customers to access and connect their onsite generation to the grid. Moreover, CHP is often not treated on par with other renewable distributed generation interconnection. States vary substantially on how and whether CHP is connected to the grid.

As of 2010, eighteen states had no interconnection standards, as reflected in Figure 0-17.⁵² In states without interconnection policies, individual electric utilities define the procedures that affect distributed generation installations. In states that do have interconnection requirements, they can vary by utility and are often not based on state-of-the-art technology or data. Interconnection is at its root a cost and “utility CHP acceptance” issue. Utility resistance can add significant cost in the form of high interconnection fees, studies, and additional hardware.

Although these policies are rooted in state and local jurisdiction, the DOE could expand upon the EPA’s analysis of interconnection standards by developing “best practices” guidance that would

⁵² U.S. EPA CHP Partnership, 2010 (<http://www.epa.gov/chp/state-policy/interconnection.html>)

allow states without interconnection standards to develop them, leveraging the efforts of other state markets.

Recommendation: Targeted Promotion of DOE CHP Demonstration Projects

The DOE has deployed funding to support its prioritization of growing CHP markets in the U.S. One quarter of ITP's funding (approximately \$25 million per year) is dedicated to distributed energy and CHP programs. In addition to this funding commitment, \$150 million of the American Recovery and Reinvestment Act of 2009 (ARRA) funding has been directed towards 'shovel-ready' CHP and district energy projects.

These DOE-funded demonstration projects are powerful examples of how CHP can benefit customers and can be tied to utility core goals of meeting reliability and energy efficiency requirements.

We recommend the DOE more specifically target regulators and utilities in markets where these demonstration projects are in place to communicate the savings and benefits of demonstration projects underway. More targeted promotion will allow the DOE to enhance the network of CHP "champions" by linking CHP benefits to the specific market interests of targeted constituents.

Recommendation: Enhance CHP Design and Operations Training

The CHP value chain involves a range of manufacturers, developers, consultants, and customers. While DOE has a robust network at the federal and regional levels to promote and educate on many aspects of CHP policies and issues, there may be opportunities the DOE to facilitate platforms for collaboration in regional markets among stakeholders to share “lessons learned” and develop voluntary training regarding topics that may enhance CHP adoption, including but not limited to: siting and permitting requirements; interconnection standards; navigating utility rates; design and operations challenges and opportunities.

Leveraging the DOE’s regional Clean Energy Application Centers for more industry-targeted knowledge-share could also be a forum for manufacturers to vet new products to customers or developers to collaborate on common challenges within a market to identify approaches to overcome those barriers collectively.

Summary

The DOE has placed a priority on promoting CHP applications through grants, incentives, tax credits and through a range of educational efforts supported by the Energy Efficiency and Renewable Energy (EERE)’s Industrial Technologies Program (ITP) and its regional Clean Energy Application Centers. The recommendations contained in this report are intended for consideration to enhance some of these already-aggressive DOE strategies to transform the U.S. CHP markets.

However, as one utility representative shared in a “Voice of the Customer” interview, “The battle for CHP is fought and won in the U.S. at the state level.” While this perspective has some merit (particularly as it relates to state policies on interconnection and utility rate designs that affect customers who have or are considering CHP installation), it is clear that the DOE plays an important role to facilitate platforms to share information, to connect the benefits of CHP systems to specific state and utility objectives, and to support the development of CHP technologies through funding R&D, incentivizing innovation, and promoting successful efforts to create a greater understanding (and potential for new approaches) to leverage CHP as an important aspect of meeting U.S. energy efficiency and carbon reduction objectives.