Attachment A

THE CADMUS GROUP, INC.

Date: October 4, 2012

To: PacifiCorp

From: The Cadmus Group

Re: Revised Overview of CHP Inputs, Data Sources, and Potential Study Results

Introduction

Cadmus is calculating the levelized cost and producing supply curves for combined heat and power (CHP) systems projected to be installed in PacifiCorp territory over the next 20 years as part of the 2012 update to the Integrated Resource Plan (IRP). This memo has three purposes: 1) explain the sources that we referenced for this analysis, 2) present data we used in the analysis, and 3) provide the results.

Cadmus presented draft results to stakeholders on August 24. Stakeholder input was considered in refining the analysis. The final results are presented in this memo, with responses to stakeholder comments included at the end.

The levelized cost is calculated based on the Total Resource Cost (TRC) perspective for all states. The IRP treats CHP systems as Qualifying Facilities, defined by The Public Utility Regulatory Policies Act of 1978 (PURPA), so the TRC is used in all jurisdictions for consistency with treatment of other generation resources in the IRP. The levelized cost, which compares the life-cycle costs to the energy savings, is based on a single system and is calculated separately for each state, installation year, system configuration (generation technology and size range) and fuel type.

The TRC levelized cost includes:

- The installation cost, less the federal investment tax credit (ITC) for systems installed before 2017. The installation cost is based on a national cost and adjusted for the cost of living in each state (using adjustment factors for cities in PacifiCorp's service territory in each state).
- The ITC is 30% of the installed cost for fuel cells and 10% for other technologies. The incentive is unaffected by utility or state rebates received. The ITC expires December 31, 2016, which is taken into account in the analysis.
- The interconnection cost, based on system size and PacifiCorp data from past installations.
- The operation and maintenance (O&M) costs that are assumed to occur annually and are adjusted to net present value.

- Fuel costs, using PacifiCorp projections for average annual natural gas costs, by service territory (Pacific Power and Rocky Mountain Power).[1]

Additionally, PacifiCorp's nominal discount rate of 6.88% is used along with an inflation rate of 1.9% to adjust the costs in future years. The costs are then divided by the energy production of the system over its life to obtain the levelized cost of conserved energy. The energy production includes a line loss factor, varying by state and sector, as provided by PacifiCorp. The energy production over the life of the system takes into account system performance degradation.

Technologies Assessed

CHP systems generate electricity and utilize waste heat for a thermal load such as space or water heating. They can be used in buildings that have a fairly coincident thermal and electric load, or buildings where combustible biomass or biogas is produced. CHP has traditionally been installed primarily in hospitals, schools, and manufacturing facilities, but can be used across nearly all segments with an average monthly energy load greater than about 30 kW. CHP is broadly divided into subcategories based on the fuel used. Nonrenewable CHP typically runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

The nonrenewable CHP systems analyzed are reciprocating engines (RE), microturbines (MT), gas turbines (GT), and fuel cells (FC). Reciprocating engines cover a wide size range, while gas turbines are typically large systems. Fuel cells and microturbines are newer technologies with higher capital costs, and fuel cells have the highest electrical conversion efficiency.

The renewable CHP assessment analyzed industrial biomass systems and anaerobic digester biogas systems.

- Industrial biomass systems, utilized in industries such as lumber mills or pulp and paper manufacturing, where site-generated waste products are combusted in place of natural gas or other fuels. Industrial biomass systems are generally large scale, using generators such as steam turbines (ST) with a capacity greater than 1 MW.
- Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including REs and MTs, and are typically installed at landfills, wastewater treatment facilities (WWTF), and livestock farms.

[1] PacifiCorp provided annual gas rate projections (nominal $/MMBtu) for use in the levelized cost analysis. Note that these prices change in each IRP scenario.

Data Sources

Cadmus reviewed many sources of data to determine the most appropriate inputs for the CHP analysis. As shown in Table 1, EPA and DOE reports on CHP technologies were used for many inputs, with other sources used for additional inputs, as appropriate.

Table 1. References for CHP Analysis

Source	Inputs	Website Link
Catalog of CHP Technologies, U.S. EPA	System Size, Installed Cost, Heat Rate, O&M Cost	www.epa.gov/chp/documents/catalog_chptech_full.pdf
Biomass Combined Heat and Power Catalog of Technologies, U.S. EPA	System Size, Heat Rate, O&M Cost, WWTF Data	www.epa.gov/chp/documents/biomass_chp_catalog.pdf
R.S. Means	State Cost Adjustment	N/A
Combined Heat and Power Partnership, U.S. EPA	Federal Investment Tax Credit	www.epa.gov/chp/incentives/
Gas-Fired Distributed Energy Resource Technology Characterizations, U.S. DOE	Measure Life	www.nrel.gov/docs/fy04osti/34783.pdf
California Self-Generation Incentive Program 10th Impact Evaluation Report	Capacity Factor	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
California Self-Generation Incentive Program Combined Heat and Power Performance Investigation	Performance Degradation	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, U.S. EPA	Agricultural CHP Data	www.epa.gov/agstar/documents/biogas_recovery_systems_screenres.pdf
Agricultural Waste Management Field Handbook, USDA	Agricultural CHP Data	policy.nrcs.usda.gov/OpenNonWebContent.aspx?content=31475.wba
Census of Agriculture, USDA	Farm Data	www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/
Landfill Methane Outreach Program (LMOP), U.S. EPA	Landfill Gas Data	www.epa.gov/lmop/
Energy Insights	CHP Eligibility by Facility Type and Size	N/A
Combined Heat and Power Installation Database	Existing CHP Installations	www.eea-inc.com/chpdata/
PacifiCorp	2011 Customer Data, Interconnection Cost, Gas Costs, Inflation Rate, Discount Rate, Line Losses	N/A

Inputs

Summaries of the key inputs for each technology are provided in the tables below. Table 2 through Table 5 list the assumptions for nonrenewable fuel systems by technology and size range. Table 6 and 7 list the assumptions for renewable fuel systems by fuel and technology.

The net heat rate, measured in Btu/kWh, is defined as the increased system fuel use (total fuel input to the CHP system minus the fuel that would be normally used to generate the same thermal output) divided by the electricity output. In biogas systems, the analysis assumes that waste heat is fed back to the anaerobic digester for generation of the biogas, so the total heat rate is used, rather than net heat rate.

For biogas systems, the cost represents the cost of the generator. Additional expense to build the digester is not included as that could be completed independently of the CHP system. Similarly, for biomass systems, we assumed the boiler and fuel processing systems are already in place at these large industrial facilities, and so only the cost for the CHP generator is included.

Table 2. Inputs for Natural Gas Fuel Cells

Input	100-250 kW	250-750 kW	750-1,500 kW
National average installation cost ($/kW)	$6,310	$5,580	$5,250
Annual O&M cost ($/kWh)	$0.038	$0.035	$0.032
Net heat rate (Btu/kWh)	4,168	6,022	6,043
Annual performance degradation	5%		
Capacity factor	0.71		
Measure life (years)	10		
Federal Investment Tax Credit through 2016	30% of installed cost		

Table 3. Inputs for Natural Gas-Fired Gas Turbines

Input	<3,000 kW	≥3,000 kW
National average installation cost ($/kW)	$3,324	$1,314
Annual O&M cost ($/kWh)	$0.0111	$0.0074
Net heat rate (Btu/kWh)	7,013	5,839
Annual performance degradation	0%	
Capacity factor	0.81	
Measure life (years)	20	
Federal Investment Tax Credit through 2016	10% of installed cost	

Table 4. Inputs for Natural Gas-Fired Microturbines

Input	<50 kW	50-150 kW	>150 kW
National average installation cost ($/kW)	$2,970	$2,490	$2,440
Annual O&M cost ($/kWh)	$0.020	$0.0175	$0.016
Net heat rate (Btu/kWh)	7,313	5,796	6,882
Annual performance degradation	5%		
Capacity factor	0.49		
Measure life (years)	10		
Federal Investment Tax Credit through 2016	10% of installed cost		

Table 5. Inputs for Natural Gas-Fired Reciprocating Engines

Input	<200 kW	200-500 kW	500-2,000 kW	2,000-4,000 kW	>4,000 kW
National average installation cost ($/kW)	$2,210	$1,940	$1,640	$1,130	$1,130
Annual O&M cost ($/kWh)	$0.022	$0.016	$0.013	$0.010	$0.009
Net heat rate (Btu/kWh)	4,383	4,470	4,385	5,107	4,950
Annual performance degradation	6%				
Capacity factor	0.40				
Measure life (years)	20				
Federal Investment Tax Credit through 2016	10% of installed cost				

Table 6. Inputs for Industrial Biomass Steam Turbine Systems

Input	<2,000 kW	2,000-5,000 kW	>5,000 kW
National average installation cost ($/kW)	$1,117	$475	$429
Annual O&M Cost ($/kWh)	$0.004		
Heat rate (Btu/kWh)	4,515	4,568	4,388
Annual performance degradation	1%		
Capacity factor	0.90		
Measure life (years)	25		
Federal Investment Tax Credit through 2016	10% of installed cost		

Table 7. Inputs for Biogas Systems

Input	FC	GT	MT	RE
National average installation cost ($/W)	$5,713	$2,319	$2,633	$1,610
Annual O&M Cost ($/kWh)	$0.025	$0.0085	$0.014	$0.0165
Heat rate (Btu/kWh)	8,705	12,400	12,703	10,357
Annual performance degradation	5%	0%	5%	6%
Capacity factor	0.71	0.81	0.49	0.40
Measure life (years)	10	20	10	20
Federal Investment Tax Credit through 2016 (% of installed cost)	30%	10%	10%	10%

The installation costs in the above tables are based on national averages. In the analysis, these values are adjusted for each state based on the cost of living in the part of that state served by PacifiCorp. These adjustment factors (the cost in each state as a percentage of the national average cost) are shown in Table 8.

Table 8. Cost Adjustments by State

	CA	ID	OR	UT	WA	WY
Material	103%	100%	100%	81%	103%	99%
Labor	114%	65%	97%	69%	93%	49%
Total	107%	88%	99%	77%	99%	82%

Levelized Cost of Energy

Cadmus calculated the levelized cost of energy for each configuration described above in each state and installation year (2013-2032). Table 9 shows the results for units installed in 2013. Levelized cost values for all other installation years are provided in the accompanying workbook (PAC 2013IRP_CHP LCOE_10-03-12.xlsx). There is a slight increase in costs for systems installed after 2016, when the federal tax credit expires. Levelized costs vary across states due to differences in cost-of-living adjustments, line losses, and gas rates.

Table 9. 2013 Levelized Cost by Configuration and State

Technology	Size Range	CA	ID	OR	UT	WA	WY
Fuel Cell	100-250 kW	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15
	250-750 kW	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14
	750-1,500 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.14
Gas Turbine	<3,000 kW	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	>3,000 kW	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Microturbine	<50 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.13
	50-150 kW	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	>150 kW	$0.11	$0.11	$0.11	$0.11	$0.12	$0.11
Reciprocating Engine	<200 kW	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
	200-500 kW	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09
	500-2,000 kW	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
	2,000-4,000 kW	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
	>4,000 kW	$0.06	$0.07	$0.07	$0.07	$0.06	$0.06
Biomass - Steam Turbine	<2,000 kW	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	2,000-5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	>5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Biogas	Fuel Cell	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	Gas Turbine	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	Microturbine	$0.05	$0.06	$0.06	$0.06	$0.05	$0.06
	Reciprocating Engine	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04

Technical Potential

The technical CHP potential was calculated based on sources described above, including PacifiCorp customer data, and data on farms, landfills and WWTFs in the PacifiCorp service territory. The total calculated technical potential is 4,301 MW. Table 10 details technical potential in rated system capacity (MW).

The average energy production is based on the capacity factors of the systems described above. To avoid double-counting opportunities across technologies, the total potential for each size range was divided into different technologies based on the distribution of existing installations for states within PacifiCorp territory. For example, for systems less than 500 kW, reciprocating engines, microturbines, and fuel cells represent 77%, 19%, and 4% of installations, respectively. For all technologies, across all states, the technical potential for energy generation is estimated to be 2,233 aMW (an average capacity factor of 0.52).

Table 10. Technical Potential

System Type	Technical Potential (MW)						
	CA	ID	OR	UT	WA	WY	Total
Natural Gas	54	162	346	2,546	449	354	3,911
< 500 kW	*31*	*82*	*156*	*1,053*	*212*	*158*	*1,693*
500-999 kW	*3*	*8*	*40*	*409*	*87*	*36*	*583*
1-4.9 MW	*20*	*45*	*108*	*818*	*151*	*110*	*1,252*
5 MW+	*0*	*26*	*42*	*264*	*0*	*49*	*382*
Biomass	12	3	141	41	31	6	233
< 500 kW	*1*	*2*	*22*	*11*	*5*	*1*	*43*
500-999 kW	*1*	*1*	*15*	*6*	*4*	*2*	*29*
1-4.9 MW	*10*	*0*	*71*	*16*	*13*	*3*	*113*
5 MW+	*0*	*0*	*32*	*8*	*8*	*0*	*48*
Biogas	2	22	31	52	8	42	157
Landfill	*0*	*0*	*1*	*8*	*5*	*3*	*17*
Farm	*2*	*22*	*29*	*44*	*3*	*39*	*139*
WWTF	*0*	*0*	*1*	*0*	*0*	*0*	*1*
Total	68	187	519	2,639	488	402	4,301

Market Potential

Cadmus applied data on recent CHP system installations in the PacifiCorp service area to determine the market potential, or likely installations in future years. The rate of assumed annual market penetration is based on actual capacity installed relative to estimated technical potential, calculated by dividing the average annual capacity (MW) of CHP installed from 2008 through 2011 by the estimated technical potential for the period 2008-2032.[2] That percentage of technical potential installed each year was applied to the 20-year technical potential estimated in this study to calculate market potential over the next 20 years, as shown in Table 11 and Table 12.

In this study, the 2032 market potential estimate is 250 MW, compared to 260 MW in Cadmus' 2011 study.[3]

[2] Technical potential for 2008-2032 was calculated by adding the actual installations from 2008-2011 to the 20-year technical potential estimated in this study. Because installation data is not yet available for 2012, we assumed the rate of installation in 2012 to equal the average of 2008-2011. The rate of market penetration was calculated as one value across the PacifiCorp service area, due to the limited number of installations.

[3] Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, Volume I, Cadmus Group, March 2011, page 84, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_VolumeI_2011_Study.pdf

Table 11. 2032 Market Potential (Based on Current Market Conditions) by State

Technology	Projected Installations in 2032						
	CA	ID	OR	UT	WA	WY	Total
System Capacity (MW)	4	11	31	153	28	23	*250*
Number of Systems	13	33	73	358	71	63	*612*
Total Energy (aMW)	2	5	18	74	13	11	*125*

Table 12. 2032 Market Potential (Based on Current Market Conditions) by Fuel

Technology	Projected Installations in 2032			
	Natural Gas	Industrial Biomass	Biogas	Total
System Capacity (MW)	227	15	8	*250*
Number of Systems	569	17	26	*612*
Total Energy (aMW)	108	13	4	*125*

Responses to Stakeholder Comments

1. The heat rate units and explanation in the memo seem incorrect and would benefit from a re-evaluation. The LCOE workbook shows different estimates for net heat rate in units of kBtu/kWh. The values are similar, but not identical to the values shown in the memo. The net heat rate is not defined but it is used to reflect the net fuel cost impact so it is the equivalent of heat rate chargeable to power. The units in the memo should read “BTU/kWh”

CADMUS: We have updated the LCOE analysis using net heat rate values (in Btu/kWh) from the *Catalog of CHP Technologies*, prepared for EPA in December 2008. The memo has been updated with the new values and reference.

2. California Self-Generation Incentive Program (SGIP) should not be used for this analysis.

- The cost averages reflect the growing pains of the distributed generation industry in an early market development period and do not represent best practices today and moving forward over the next twenty years.

  CADMUS: The equipment cost values are now based on the *Catalog of CHP Technologies* report, rather than California SGIP data. The national averages in that report are adjusted for each state in the PacifiCorp territory based on cost of living adjustment factors from RS Means. Interconnection costs were added using a formula for interconnection costs based on equipment size that we developed using data from PacifiCorp of actual costs.

- The California SGIP has historically focused on small CHP systems, primarily systems less than one megawatt with reduced incentives for systems up to five megawatts. Larger systems have lower capital costs, lower O&M costs, higher thermal utilization, and higher load factors than the smaller systems that were the focus of the SGIP program. As a result the most economic portion of the CHP market is left out of the Cadmus economic comparison.

  CADMUS: SGIP system sizes are no longer used in the analysis. The LCOE analysis has been modified to examine two to five size ranges for each technology, rather than one average for each technology. Different equipment costs ($/kW) are used for each of these size ranges, based on data from the *Catalog of CHP Technologies* report.

- Larger CHP systems, particularly gas turbines and reciprocating engines, show economies of scale and have lower unit costs. This is particularly true for gas turbines which can often be one to two orders of magnitude larger for CHP systems than the 3,200 kW used in the Cadmus report. It should also be noted that the low end 3,200 kW gas turbine system modeled in the Cadmus analysis has relatively high capital cost and lower efficiency than gas turbine systems even slightly larger in size.

  CADMUS: As described above, the updated analysis includes a range of system sizes for each technology.

- The program stopped providing incentives for natural gas fired reciprocating engines, microturbines, and gas turbines in 2007. Therefore, the population of estimates for these technologies is largely out of date.

CADMUS: SGIP data is no longer used for most parameters in this analysis.

- The original purpose of the California SGIP program was to promote new generation capacity at a time when California was facing capacity shortages. Because of this, many of the initial CHP systems installed under the program appear to have been oversized in relation to site thermal loads and CHP system thermal utilization suffered.

  CADMUS: The updated analysis is based on data from *Catalog of CHP Technologies*, rather than using this SGIP data.

- Heat rate values are all quite high because they are based on the historical observation of low thermal utilization rates in the early California SGIP CHP systems. The values do not represent the capabilities of a well-designed and maintained CHP system today. These high heat rate estimates significantly overstate the LCOE calculations in the Cadmus report.

  CADMUS: The updated analysis uses heat rates from *Catalog of CHP Technologies*, rather than SGIP.

- The observed historical California SGIP installations significantly undervalue the expected capacity factor for CHP in high load factor applications. Each of the CHP systems is capable of having an availability factor of 95%. An economically-designed installation must be based, as much as possible, on continuous system operation.

  CADMUS: While a 95% capacity factor is theoretically possible, Cadmus believes it is more accurate to base our projections on actual capacity factors and degradation rates of operating systems. We understand the limitations in applying SGIP data for PacifiCorp so we have replaced it with other sources where possible, but we have not found better sources for capacity factor. The performance degradation rates are still based on SGIP data, but were updated based on a report (*Self-Generation Incentive Program Combined Heat and Power Performance Investigation*) that breaks down the SGIP degradation into more detail, allowing us to modify our analysis to apply only the portion of degradation based on reduction of system efficiency. If other references can be provided, Cadmus will review them and consider if they can be used to refine our analysis.

3. The assumed price of natural gas is too high. Values are higher than those in the latest EIA Annual Energy Outlook.

CADMUS: The updated analysis uses natural gas prices from PacifiCorp's latest forward price curve. These values are used to calculate a base case levelized cost to include in the potential study report.

Note that this base case levelized cost is not used for IRP modeling. Rather, the IRP models will apply low, medium, and high natural gas price forecasts as the fuel cost for CHP resources in line with their treatment as thermal units.

4. Why is CHP treated on a TRC basis in Utah?

CADMUS: These sites are considered PURPA Qualifying Facilities rather than Demand-Side Management opportunities and are thus treated like other supply-side resources. As such, the administrative adder has been removed from Cadmus' analysis and replaced with PacifiCorp's interconnection cost.

5. Where the value of heat generated by the CHP system taken into account?

CADMUS: For non-renewable options, the analysis assumes that waste heat offsets fossil fuel consumption for space and/or water heating and thus does not save electricity. Net heat rates are used so the fuel use included in LCOE calculations is only the increased fuel use for electricity generation.

The analysis assumes that biomass systems are installed at facilities that already have wood/paper waste and are using that waste in a boiler. The addition of a generator would add the benefit of electricity generation through CHP. Since the heat is already being generated, the analysis doesn't include a waste heat benefit and also doesn't include capital costs other than the generator.

In biogas systems, the analysis assumes that waste heat is fed back to the anaerobic digester for generation of the biogas.

6. Are the CHP plants assumed to dispatch against market electricity prices or will they operate in response to the host facility heat/electricity needs?

CADMUS: CHP plants are assumed to dispatch against market prices.

7. O&M Costs – The O&M estimates used in the Cadmus report are from a source that is out of date. The costs from the CEC's online Distributed Energy Resources Guide are shown in the table below. With the exception of the very low estimate for fuel cell O&M, the difference in cost estimates do not make a large difference in the LCOE calculation.

O&M Costs, $/kWh	Size, kW	Cadmus - First Draft	CEC	Cadmus - Updated (from EPA reports)
Reciprocating Engine	620	$0.013	$0.016	$0.009 - $0.022
Microturbine	170	$0.012	$0.022	$0.016 - $0.02
Fuel Cell	520	$0.005	$0.035	$0.032 - $0.038
Gas Turbine	3,200	$0.013	$0.010	$0.0074 - $0.0111

CADMUS: The updated analysis uses O&M cost data, added to the table above, from the Catalog of CHP Technologies report and its companions report suggested below, the Biomass CHP Catalog of Technologies. We don't see a date on the CEC DER Guide so we cannot confirm which is the most current source.

8. The biomass LCOE of 2 cents/kWh is quite low.

- The estimate is based on capital costs of $1,800/kW. This estimate should likely be at least doubled. A recent study reviewed by ICF, details confidential, showed capital costs for a 20 MW biomass power plant at $4,800/kW and a 55 MW plant at $3,200/kW.

  CADMUS: The updated analysis uses capital cost data from *Catalog of CHP Technologies*. If another reference can be provided (with sufficient detail for every technology considered), Cadmus will review its appropriateness to determine if it is more suitable for this analysis.

- In the Cadmus report, the biomass feedstock is assumed to be used at no cost. Solid biomass fuels need to be collected and prepared, and the costs for this need to be taken into consideration in the analysis. It is unrealistic to assume that there are no costs associated with this part of the system.

  CADMUS: In this analysis, it is assumed that the biomass is a waste product generated on site and applicable facilities already include feedstock processing, so any additional collection and processing cost to use a generator is minimal.

- O&M costs assumed in the Cadmus report are very low. A solid fueled system requires more operating and maintenance labor expenses as well as more fuel processing and handling expenses than does a natural gas fired system. (For more detailed information, see "Biomass CHP Catalog of Technologies" from the EPA CHP Partnership at http://www.epa.gov/chp/basic/catalog.html#biomasscat)

  CADMUS: The referenced report was used in the updated analysis.

9. The analysis underestimates the CHP potential by excluding bottoming-cycle CHP, also known as waste heat to power (WHP). These systems convert excess, otherwise-wasted thermal energy or pressure from industrial processes or pipeline compressor stations into electricity. Although the Cadmus report analysis notes the difficulty in finding information to quantify the potential, it is reasonable to consider that the value is greater than zero.

CADMUS: We have researched WHP systems and identified several challenges:

- There is currently very little WHP installed in US (33 sites, 557 MW, excluding landfill gas)
- Only applicable in industries with high temperature heat produced (e.g. metal and chemical manufacturing)
- The technical barriers are relatively significant (e.g. space limitations, disperse waste

heat sources, low volume/seasonal operations)

Although there are potential energy savings from WHP, the low market awareness and willingness to adopt at this time, coupled with relatively significant technical barriers, indicate the market potential for these applications is small.