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Performance Review of the U.S. General Services Administration Public Building Service, National Capital Region Heating Operation and Transmission Division

Sankar Narayanan[a], Gearoid Foley[b], Gonçalo Cardoso[c], Michael Stadler[d]

[a] **Microgrid Labs**
[b] **Integrated CHP Systems Corp.**
[c] **Lawrence Berkeley National Lab**
[d] **Center for Energy and Innovative Technologies (CET)**

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EXECUTIVE SUMMARY

This report is a review of the U.S. General Services Administration Public Building Service, National Capital Region Heating Operation and Transmission Division herein after called HOTD. While many reports and audits have been developed over the years [1], this report looks at the strengths and weaknesses of the entire system including the load base from an operations perspective. It does not take into account specific GSA regulations but rather looks at HOTD as a typical commercial concern and makes recommendations for the future economic viability of the system.

It is generally agreed that one of the main problems facing the future viability of HOTD is the perceived high cost of steam service and the resultant threat of defections by customers [1]. It is assumed that loss of further load would force the cost of steam service higher resulting in increased defections. While the cost of HOTD's steam service is high relative to other district energy systems, the main reason for this high cost of service is the lack of diversity among HOTD's client base. All major customers act in effect like typical office buildings with very high load demands during working hours and minimal demands during non-work hours. This results in the need for HOTD to make a high capacity available while revenue, which is based on energy flow, is a fraction of the capacity. Likewise, customers' chilled water demand requires a high cooling capacity be made available while average usage is low. In 2014, plant peak steam production was 690 Mlb per hour while average steam production was only 217 Mlb per hour and the plant's electric peak demand was 11.9 MW while the average demand was only 3.9 MW. The need to maintain a high level of steam capacity availability versus average usage is further exacerbated by the age of the boilers which requires increased capacity availability due to low reliability of existing equipment. While HOTD staff has done an excellent job of maintaining capacity availability, it is not without constant repair work and cost. HOTD is probably unique in its lack of diversity of clients which is a clear impediment to reducing rates. When looking at other district steam and/or chilled water systems such as Baltimore, Philadelphia or New York, they all include a much greater diversity of clients and are therefore in a better position to provide lower service rates.

One of the recommendations of this report is that an effort should be made to expand the customer base to incorporate more institutional type customers such as multi-family residential, hotels, healthcare and colleges. HOTD does not need additional clients with the same profile as the existing '9 to 5' customers but could benefit from the addition of different market sector clients.

It is also recommended that HOTD should consider a different approach to charging their clients and adopt a more 'regulated utility' type tariff development approach that would separate demand from energy as well as separate special services such as consulting. Furthermore HOTD should evaluate their existing customer base in order to identify client load factors. This would provide essential knowledge in future efforts to more appropriately charge clients as well as help existing customers better understand the reasons for the perceived high cost of service. Under the current approach of charging all users the same rate, 'good' clients subsidize 'bad' clients (i.e. ones with very low load factors), which serves to promote the defection of the good customers. Identification of poor load factor clients would provide an opportunity to resolve some of the load factor issues and, particularly for large customers with poor load factors, will help make a sound business case on the need for the existing cost levels and give them a better basis for comparison of separate boiler/chiller plants.

HOTD should consider developing a proactive marketing campaign to defend itself against defections. Many customers already have been and will continue to be, targets of private third-party energy service companies who are trying to persuade existing clients to defect from HOTD. Together with a realignment of costs, a better understanding of customer profiles and a clearer statement of the advantages of the district energy system, HOTD needs to fight back to retain its customer base.

HOTD provides a very unique opportunity to the National Capital Region to provide the backbone for a resilient microgrid of the future. The existing thermal loop and access ways as well as the central plant location and existing facilities provide a significant portion of any future microgrid in the region. This opportunity needs to be more fully evaluated but it should be immediately recognized as a major asset for any NCR microgrid and any future investments, alterations or business decisions relating to HOTD should incorporate this fact into the decision making process.

While the existing CHP plant has been subject of review prior to this report, when looking at the CHP plant operation from today's perspective it is doubtful that the plant provides any economic advantage when operating to provide export power. Unless the plant can be used to provide the majority of its power output at rates higher than the current wholesale market which is typically around $0.04 per kWh, it will not provide economic advantage. Under current arrangements where most of the power is exported to the wholesale market, it is recommended that only one unit be run from mid-April to mid-October whereby most of the CHP electric output can be dedicated to the HOTD plant and thereby offset retail rates. It should be recognized that the existing 10.4 MW plant does provide the added benefit of increased resiliency over diesel engines and could be the basis for provision of emergency or non-emergency power to other facilities if future conditions and regulations allowed such use. The plant could also be used to provide demand reduction services or wholesale power during periods of high grid power cost which should be further investigated.

The existing HOTD steam boiler capacity is mainly based on 1933 coal boilers which have been converted to natural gas with oil as a backup fuel. These boilers are well past their expected life span and will need to be replaced at some time in the future. Due to the good efforts of HOTD staff, there is little potential for improvements in efficiency at the plant and it is thought that there is no significant cost savings to be gained from replacement of the boilers other than reduced maintenance costs. Therefore a boiler plant capital replacement program fund does need to be incorporate into the cost base.

While the existing plant including steam boilers, electric chillers, CHP plant and distribution system is operated well, improvements in equipment dispatch and load control should provide an opportunity for cost savings. Current operations and energy purchasing strategies are essentially based on manual control without real-time reference to customer loads, distribution utility tariff schedules or wholesale market conditions. It is recommended that a more comprehensive operating strategy based on load projections, tariff schedules, weather patterns and wholesale market conditions be implemented.

Lawrence Berkeley Labs' DER-CAM program should be investigated as a cost effective resource to refine operational dispatch of the plant resources.

While the existing CHP plant has been run at full capacity all available hours, the intermittency of operation has resulted in poor annual demand suppression. During 2014 when the plant electric demand with CHP operational should have shown a peak annual demand of approximately 2 MW, in fact the annual utility demand peaked at 8.5 MW. Further investigation of the reason for the short term interruptions in summer operation of the CHP plant as well as a tariff analysis to determine the cost of such operation should be further investigated. Based on typical utility tariff rates and capacity obligation charges, this intermittency in summer operation of the CHP plant would cause a significant loss in anticipated savings.

Additional opportunities for load management such as CHW storage, customer demand management programs and better utilization of the existing steam chillers targeting reduction of both steam and electric peak loads exist. Proposed energy conservation measures such as addition of variable frequency drives to pumps and upgrade of the condensate return system will provide a good return on investment but small savings relative to the overall plant operation. In addition the existing boiler plant steam supply header operates at 250 psig but the main boiler plant is rated for 400 psig operation according to our discussions. A reduction in steam header supply pressure and integration of a steam turbine generator that would generate base load electric output offers the potential for additional operating savings. It is recommended that these strategies and opportunities be further investigated.

In summary, the existing HOTD plant can improve its future viability through:

- Better accounting of customer costs
- Addition of new institutional type customers
- Better outreach to the customer base to defend against defections
- Recognizing the potential for HOTD to act as the backbone for a NCR microgrid
- Improved dispatching of existing resources
- Operation of existing CHP plant to offset retail rates
- Continued improvements to existing equipment

While this report does not take into account many of the overriding GSA regulations, it is also important to note the uniqueness of the HOTD plant and customer base and the need for a unique strategy to maintain the plant in operation. While it is acknowledged that there are many issues with the existing plant operation, it should not be forgotten that HOTD embodies a national center of excellence for thermal distribution systems, provides highly reliable and efficient service and presents a very real opportunity to provide a sustainable and resilient microgrid for the NCR. To this end every effort should be made to maintain HOTD in service.

INTRODUCTION

Built in 1933, the HOTD is a district level provider of heating and cooling services to several facilities (both GSA and non-GSA) in the national Capital region. The HOTD complex comprises the following systems:

- 6x Gas fired boilers of different capacities
- 8x Electric chillers
- 2x 5.2 MW CHP units
- Steam and chilled water distribution - 12 miles of tunnels and buried lines.

HOTD provides steam service to over 70 locations, and chilled water services to 13 locations including, including some non-federal buildings. Major customers include:

- Department of Agriculture
- Department of Energy Forrestal
- Smithsonian museums
- National Gallery of Art

HOTD has to ensure services are maintained during a possible interruption of gas or electric service to the central plant. Towards this HOTD maintains an alternative fuel supply as well as the capacity to generate sufficient electricity to operate the plant's primary steam and chilled water.

HOTD's services come at a premium and are not directly competitive compared to the perceived cost of self-performing through installation of on-site energy plants. This leads to concerns relating to potential future customer defections which could affect the long-term economic viability the plant. Consequently, GSA wants to evaluate different options to restructure HOTD operations.

This study is undertaken to assist GSA in this exercise with the main objectives of providing a high-level overview on the following:

- Plant operation
- Major challenges and concerns
- Scope for improvement

As part of the study, two site visits were conducted on Sep 15 and 29, 2015. The visits included both a plant tour and meetings with the team to understand the operations, challenges, and concerns. This report is based on our finding during the site visit and analysis of the data provided by HOTD.

We gratefully acknowledge the kind assistance of Mr. Joe Eberly, Mr. Dave Mbonu and his team for their active participation and support. Our special thanks also to Mr. Michael Albritton and Mr. William Willis for the plant tour and Mr. Wayne A. Bather for providing us with the operational data.

HOTD ENERGY DATA REVIEW AND ANALYSIS

Hourly interval data for electric imports, exports, CHP production and plant electric energy usage was provided. This data provides a detailed account of the plant operation as well as the CHP system operation and is useful in determining the overall plant's performance and utilization. Figure 1 provides a graph of the available data and demonstrates that the CHP plant is electrically oversized for the needs of the plant resulting in over 55% of the CHP plant output being exported during 2014. Even in mid-summer when the plant power needs are highest due to electric chillers, the CHP plant still exports power except at the highest peak chiller loads.

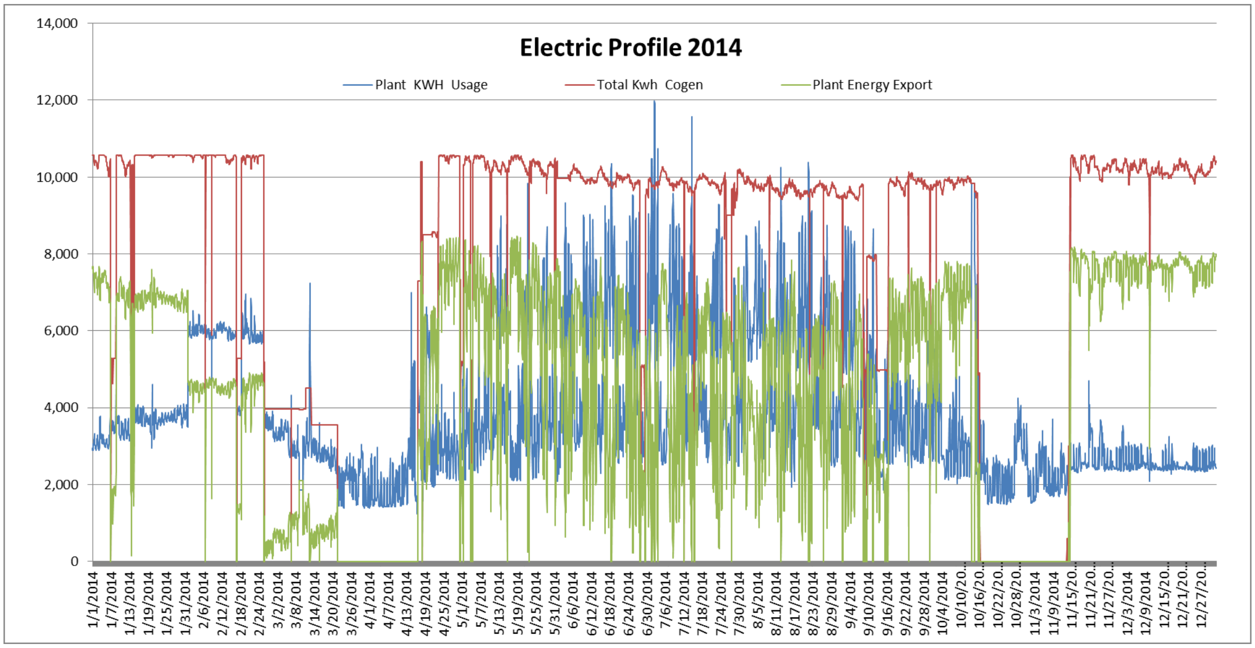

Figure 1 HOTD Electric Energy Profile, 2014

Figure 2 provides a graph of the HOTD plant electric energy use using all available data from Jan 1, 2014 through September 30, 2015. The internal plant electric energy utilization is determined by subtracting the exported power from the CHP plant output and adding any imported power through the utility. This data follows a typical space cooling driven profile with significant variation in power demand through different seasons as well as from day-to-day. The plant average power demand for 2014 was 3,866 kW while the peak demand was 11,974 kW or 3.1 times the average demand. The profile shows an unusual increase of 2 to 3 MW in power demand in February 2014 as well as other occasional short-term spikes in power demand. These events are unexplained and should be investigated further in future studies in order to determine if these are unusual events or are to be anticipated in any future plant operation design. The base load through the winter of 2014 and spring of 2015 is approximately 2,500 kW.

Figure 3 provides a graph of HOTD hourly steam production for the period from Jan 1, 2014 through September 30, 2015. This again exhibits a typical profile associated with space heating in winter and reheats in cooling season. For the periods from the end of January through the beginning of June 2014 as well as through much of August 2014, the data acquisition system did not appear to be working and no data was provided for these periods. For the 12-month period from 10/1/14 through 9/30/15, the total steam production was 1,901,649 thousand pounds (Mlb) with an average production of 217 Mlb and a peak production of 690 Mlb or 3.2 times the average demand.

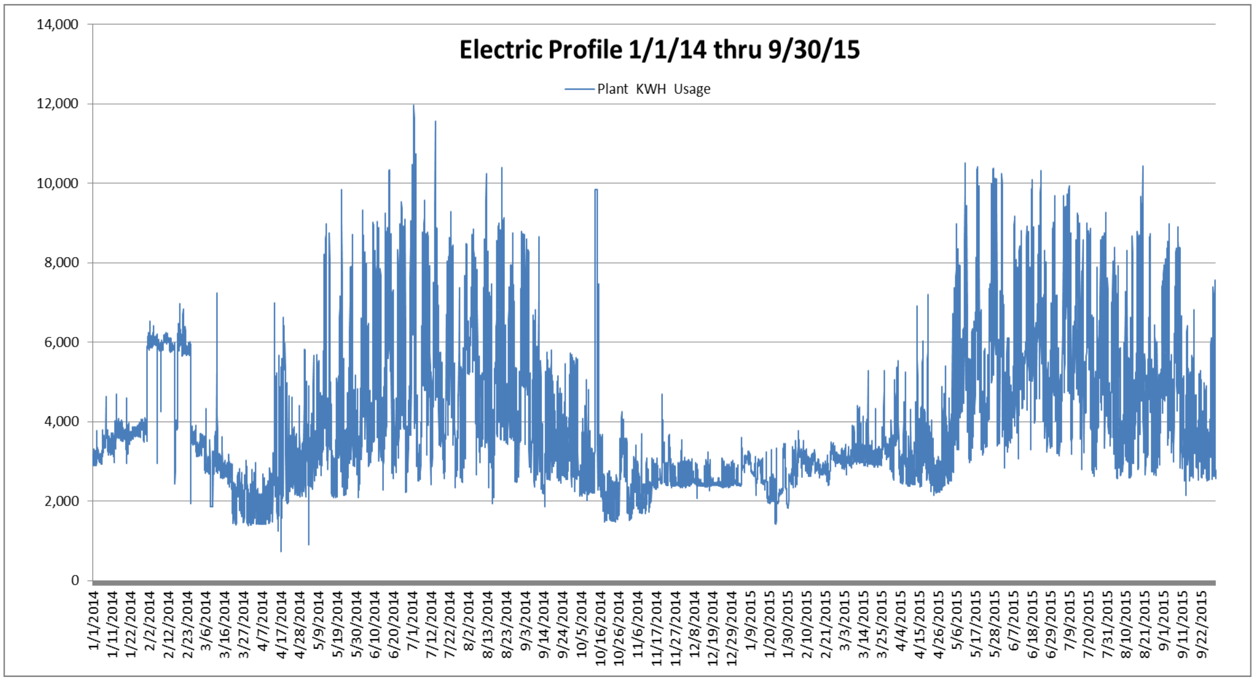

Figure 2 HOTD Plant Electric Energy Demand Profile

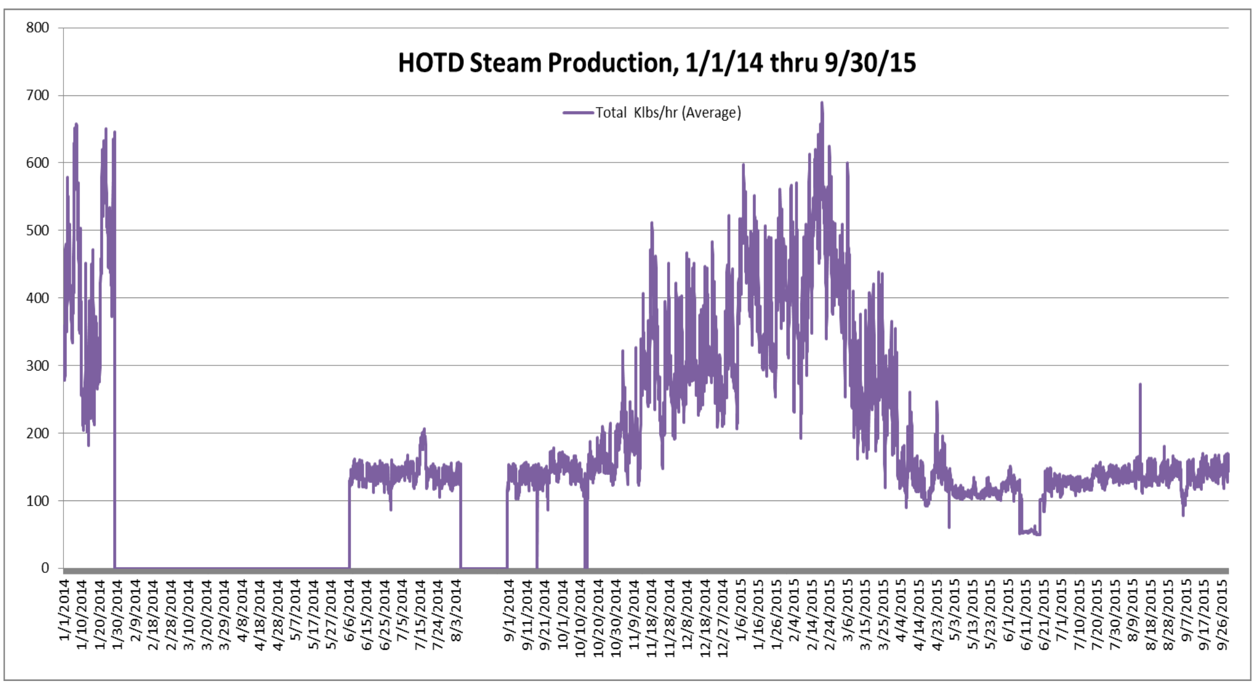

Figure 3 HOTD Steam Production Profile

Interval data for chilled water production was not made available so Figure 4 graphs the total chilled water sales in terms of ton-hours per month for 2014. The total ton-hours sold for the period was 25,917,430, the average tons per hour sold for the period was 2,959 and the peak hourly sales recorded in August (based on daily billing data) was 13,575 tons. Based on the monthly billing data, the ratio between July and August sales was 1.157 and therefore we estimate the peak hourly sales to be 15,706 tons which is 5.3 times the average hourly sales.

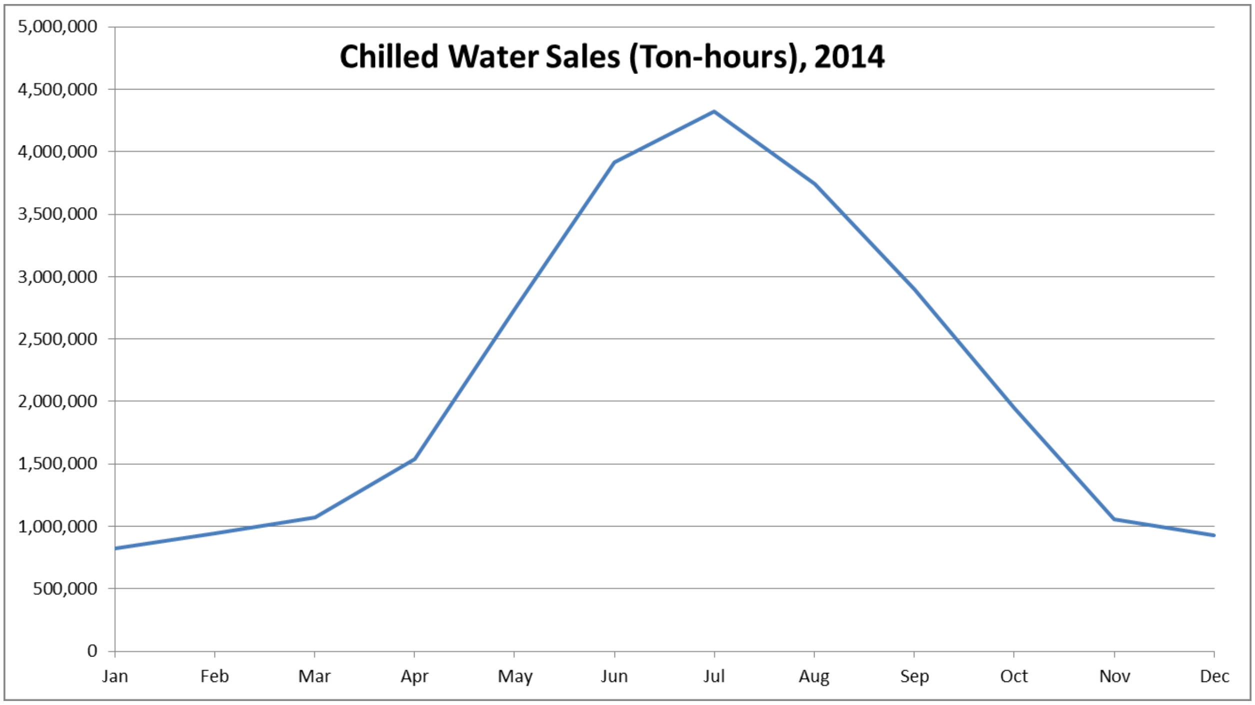

Figure 4 HOTD Monthly Chilled Water Sales

It should be noted that the ratio of peak demand to average demand is not intended to uncover any problems within the operation of the system. Rather it is instructive to understand the nature of the loads being served as well as the capital investment obligation versus revenue anticipated for both HOTD as well as prospective new clients or existing clients who may be considering independent operation. It should also be noted that much of the electric peak loads are driven by chiller plant peak loads.

HOTD ENERGY COST REVIEW

HOTD's steam price to customers is set at $38.90 per thousand pounds (Mlb) which is considered to be high for such services. The rate incorporates all related costs including fuel, maintenance, labor, materials, depreciation and debt service. Figure 5 provides an excerpt from the ConEd New York steam tariff presenting the basic usage charges for general service [2]. Over 80% of HOTD customers used in excess of 1,000 per month on average during 2014 and therefore it is assumed that under the ConEd tariff, the average HOTD customer charge would be similar to ConEd. However, ConEd is recognized as one of the most expensive steam systems in the US. According to a report in the Pittsburgh Post-Gazette in February 14 2013 [3], the Pittsburgh Allegheny County Thermal district energy plant steam price was reported to be 'around' $27.50 per Mlb.

PSC NO: 4 - Steam	Leaf: 68
Consolidated Edison Company of New York, Inc.	Revision: 9
Initial Effective Date: 03/01/2014	Superseding Revision: 8
Issued in compliance with order in Case 13-S-0032 dated 02/21/2014	

SERVICE CLASSIFICATION NO. 1
GENERAL SERVICE

Applicable to Use of Service for

All Purposes

Character of Service

Continuous; supplied at an average gauge pressure in excess of 125 pounds.

Rate

Usage Charge (per Mlb of steam in each monthly period)

For the first	20 Mlb	$15.577	/ Mlb
For the next	30 Mlb	$48.497	/ Mlb
For the next	950 Mlb	$37.914	/ Mlb
For excess over	1,000 Mlb	$36.496	/ Mlb

Customer Charge

$1,219.05 per month, exclusive of increase in rates and charges. A Customer who requests a temporary discontinuance of service will be required to pay the monthly customer charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the monthly customer charge for each month that service was discontinued.

Figure 5 ConEd General Steam Service Tariff [2]

While this report does not incorporate a rate tariff analysis, it is clear that other district energy systems incorporate a variety of approaches to steam tariff development which may benefit HOTD. Many district energy systems include a separate capacity charge for providing service apart from the steam energy charge. In addition, some services that are currently incorporated into the HOTD energy cost are charged separately by other district energy systems. Figure 6 provides an extract from the ConEd tariff that provides rates for work at customer sites which are charged separately from the energy rates.

PSC NO: 4 - Steam | Leaf: 40
Consolidated Edison Company of New York, Inc. | Revision: 2
Initial Effective Date: 03/01/2014 | Superseding Revision: 0
Issued in compliance with order in Case 13-S-0032 dated 02/21/2014

GENERAL INFORMATION - Continued

4. Special Services Performed by the Company for Customers at a Charge - Continued

4.1 Special Services at Stipulated Rates - Continued

4.1.2 Services - Continued

b. Historical Usage and Billing Information

A statement of the account's usage and billing information, if available, will be provided at a Customer's request at a charge of $15.00 per year of information from two to not more than six years from the date of the request. There will no charge for a statement of usage and billing information for up to the most recent 24 months.

c. Investigation at the Premises

There will be a charge if the Company visits a premises at the Customer's request to investigate a leak, pressure condition, or other problem, and the Company determines that there is a problem with the Customer's piping and/or equipment. The charge will be $453.00 for an investigation during Business Hours and $503.00 for an investigation begun or completed After Hours.

d. Steam Repairs and Other Services

Upon a Customer's request, the Company will perform steam repair services as set forth below. The charge for each service is inclusive of the cost of materials, handling, and labor.

Service	Charge during Business Hours	Charge After Hours
Replace 300 # flange valve (1" to 4")	$1,666.00	$1,778.00
Repair/replace trap and associated equipment	$ 651.00	$ 692.00

Figure 6 ConEd Steam Special Services Rate Tariff [2]

HOTD chilled water energy is provided at a rate of $0.27408 per ton-hour which is considered to be low by comparison to many district energy systems. The HOTD cost breakout provided does not detail how the electric output from the CHP plant which provides most of the energy for cooling is considered in the makeup of chilled water costs. Expenses for gas and cogen maintenance appear to be mostly charged against the steam system while gas to the cogen system as well as cogen electricity is mainly used to develop chilled water. A realignment of costs may result in increased chilled water rates and reduced steam rates which may be more acceptable to the customer base than current rates.

Table 1 provides a breakout of the direct steam and chilled water (CHW) expenses exclusive of depreciation and debt service that are used to develop the energy rates. Table 2 provides a breakout of labor related cost centers included under the maintenance and administration cost centers demonstrating that the total in-house and contract services including equipment and distribution system maintenance totals 41% of the total steam and chilled water direct expenses.

Cost Center	2014 Total	% of Total
UTILITIES	$26,860,519	53%
MAINTENANCE	$ 14,025,377	28%
ADMINSTRATION	$ 8,270,885	16%
BUILDING SUPPORT	$ 1,201,368	2%
Total Steam & CHW Expenses	$50,358,149	

Table 1 HOTD Steam and Chilled Water Cost Breakout, 2014

Sub-Category Cost Center	2014 Total	% of Total
Personnel	$9,826,996	20%
Contracts	$4,963,779	10%
System Maintenance	$5,388,415	11%
Total Steam & CHW Expenses	$50,358,149	

Table 2 HOTD Steam and Chilled Water Cost Breakout, 2014

Many district energy systems are regulated by state utility commissions and steam rates are typically developed through a public utility commission rate review that looks at all allowable costs and allowable rates of return with an adjustment factor allowed to correct the approved rates to cover variable costs such as natural gas fuel prices. This approach typically breaks out fixed and variable costs into capacity and energy components as well as providing allowances for special services such as customer repairs. Given that HOTD currently provides many non-energy related customer services as well as support for GAS facilities outside of its own customer base, it is expected that a rate calculation strategy more in line with regulated steam district energy systems may provide a clearer view of costs and allow a better apportionment of costs for high load factor clients versus low load factor clients. This would provide a better defense against defections whereby ‘good’ customers are provided a lower cost of service while poor load factor clients whose cost of service would increase would also have a significantly higher cost associated with defection.

Other strategies such as demand response programs targeting reduction of peak loads or removal of small customers with very poor load factors should also be considered to help reduce the cost of service. An accounting of the fixed and variable costs associated with providing energy services would help to more accurately identify cost reduction strategies.

It is understood that district energy system charges are high when compared to the operating cost of on-site steam boilers and chillers. However, district energy systems offer significant advantages over on-site energy systems including reduced operating risk, elimination of emissions reporting, reduced mechanical system space requirements, etc. Figure 7 provides a slide taken from a Veolia NA presentation [4] on the case for district energy systems. Table 3 provides a comparison of a district energy plant versus individual on-site boilers according to the Pittsburgh Allegheny County Thermal district [5].

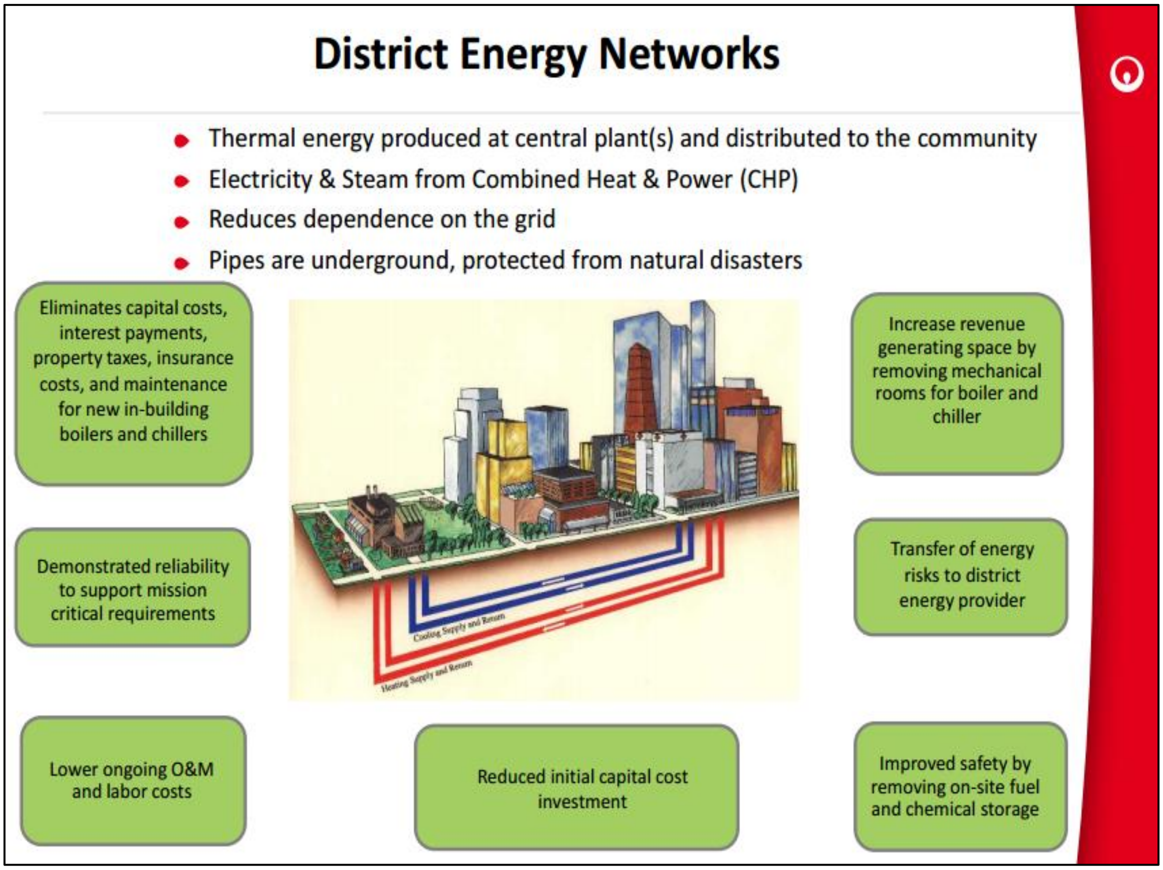

Figure 7 Veolia Presentation slide on Advantages of District Energy

PACT SYSTEM	INDIVIDUAL BOILER INSTALLATION
One stand alone steam plant with back-up boiler operation, professionally maintained to provide reliable, safe and efficient steam heat to the distribution system.	Boiler installation occupying valuable building square footage requiring continuous maintenance and service without back-up.
Financial strength and equity of PACT has	Large capital investment required to fund

provided for in excess of $40,000,000 of historical capital invested in the boiler facility and distribution system to provide the highest level of reliability.	installation of boiler, annual maintenance will be required to avoid long term degradation of the system.
PACT licensed operators are on staff 24/7 within the plant and accessible to the entire distribution system as required.	Utilization of internal staffing or hiring of new personnel, additional taxes, benefits, payroll and associated costs required to maintain boiler, possible licensure requirement.
PACT's boiler vent stack located within the plant is single use and in compliance with all government and environmental regulations.	Building must have a dedicated boiler vent stack, installed or adapted to fit the outside of the structure. Must pass emission and environmental regulations.
Because PACT purchases such large gas quantities and due to its own transportation line and favorable rate structure, PACT is uniquely positioned to purchase gas long term under contract.	Fuel cost will vary depending on commodity rates, transportation, basis, and fuel shrinkage with ongoing evaluation required by building owners to develop an aggregate fuel cost pricing/quantity strategy.
PACT maintains deep wells as its primary source of water requirements, along with sewage and electric power are all provided by PACT rate base.	Requires contract at current rates for city water, sewage and electrical associated costs, effected by usage.
All water treatment chemicals required to comply with boiler operating requirements are handled by PACT.	Requires constant monitoring, adjustment and purchase of the required chemical inventory for the boilers system.
PACT meets or exceeds all operating/liability insurance requirements for replacement cost of its facility and distribution system.	Must purchase the applicable insurance for replacement cost and/or liability coverage of having a boiler located in the building.
PACT employees, operational management teams and executive staff provide for an extremely efficient, dedicated and reliable steam heating system.	Must dedicate executive time/cost for decisions effecting operations.
The PACT steam heating plant and distribution system has consistently provided uninterrupted steam heat to it's members for over 25 years.	A boiler failure in the midst of winter at an inopportune time could have devastating effects on the building structure and tenant well being.

Table 3 Pittsburg Allegany County Thermal Comparison

PLANT OPERATION REVIEW

Plant Electricity

For 2014 the total electric energy used by the plant was 33,870,263 kWh while the maximum plant demand was 11,974 kW recorded at 2 PM on July 2nd. The resulting load factor for the HOTD plant is 32.3% which is considered to be very low. While this is generally a symptom of the major power load being related to cooling, it is potentially a significant cost issue. Depending on the utility rate tariff structure, such a load factor may prove to significantly increase the cost per kWh of energy delivery should HOTD decide to scale back on CHP production or when the CHP plant is unavailable.

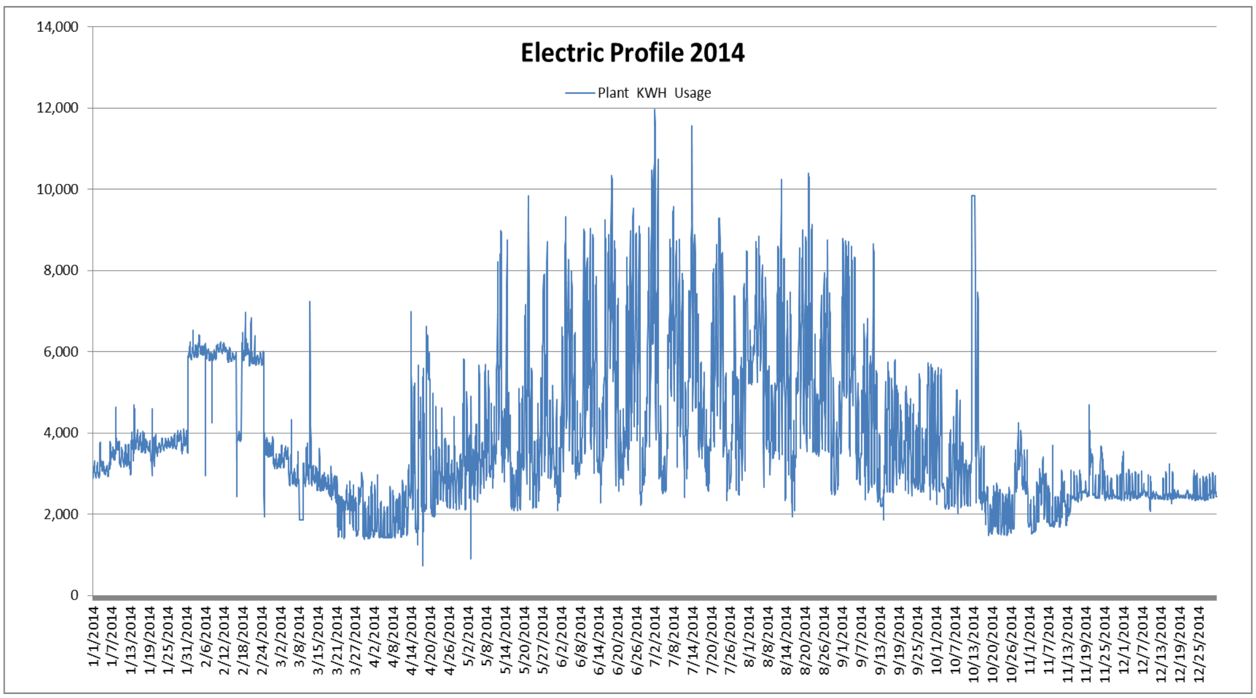

Figure 8 HOTD Electric Energy Demand Profile, 2014

In fact, for the period studied as presented in Figure 9, the total power imports were 3,064,907 kWh, the average hourly power import was 350 kW and the peak hourly import was 8,510 kW resulting in a 4% load factor. This forces the utility serving the plant to provide 8.5 MW of capacity while only 0.35 MW is used on average.

Figure 10 graphs HOTD hourly electric demand versus hourly dry bulb temperatures for Washington, DC. This demonstrates that the summer electric load which is mainly driven by cooling is related to client building occupancy. During holiday and weekend periods, HOTD electric demand varies between 3 and 5 MW while during peak occupancy periods, the demand exceeds 10 MW. Figure 11 expands the scale to look at a typical week in July when ambient temperatures were consistent and clearly identifies the relationship between day-of-week and the facility’s electric demand. What is also apparent from Figure

11 is that there is significant diurnal variation in electric load which presumably is related to client cooling requirements. It appears that many client buildings operate a night setback schedule causing considerably load to be applied on the system at 4 AM which then drops off at 6 PM.

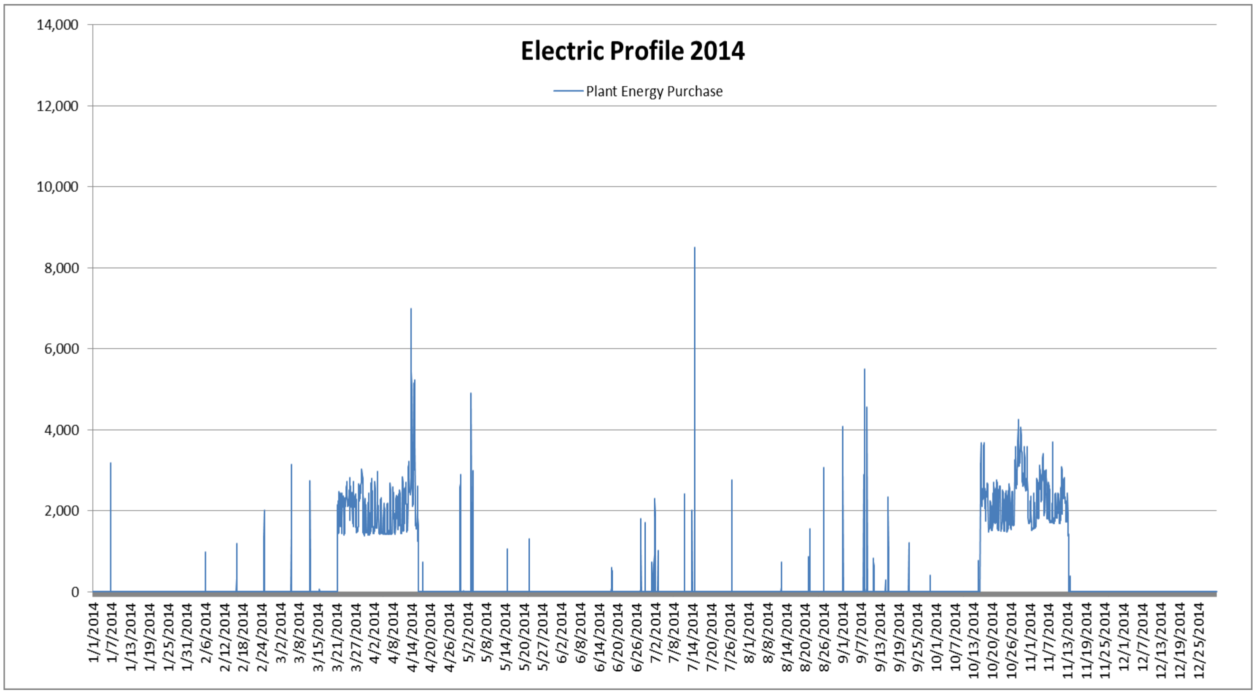

Figure 9 HOTD Electric Energy Purchases in kW per Hour, 2014

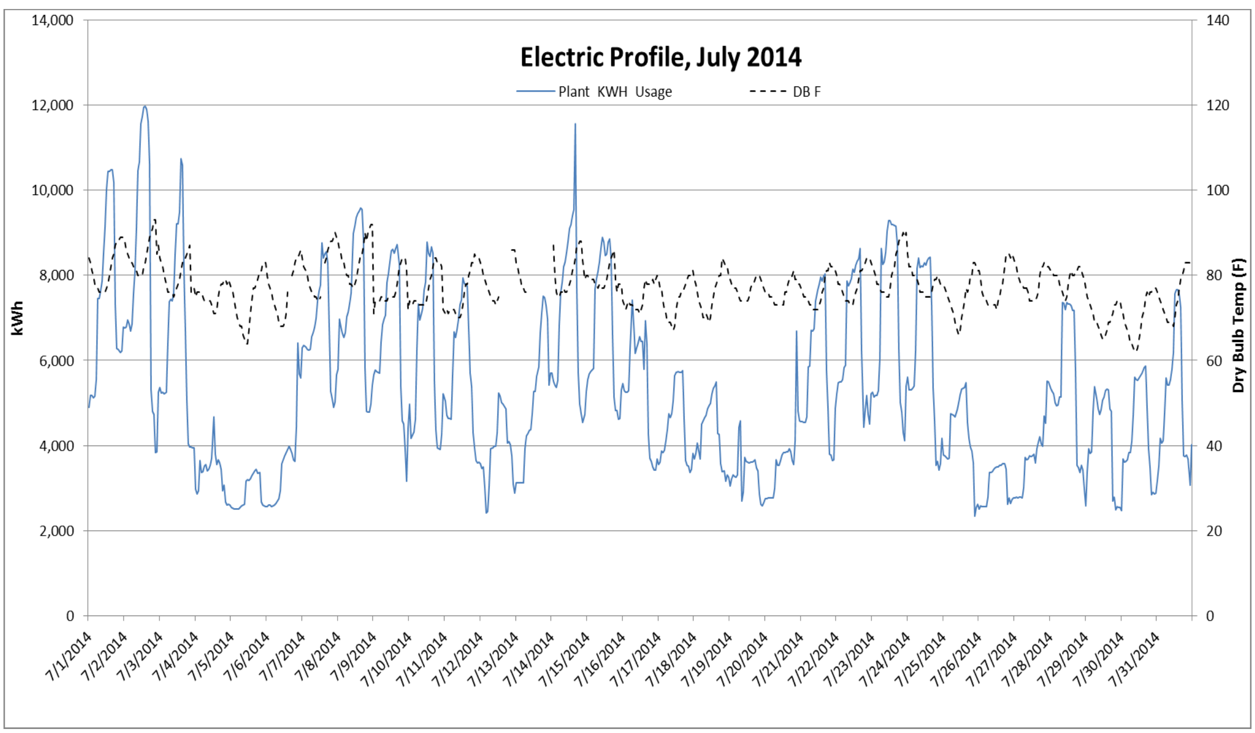

Figure 10 HOTD Electric Profile and Ambient Temperature, July 2014

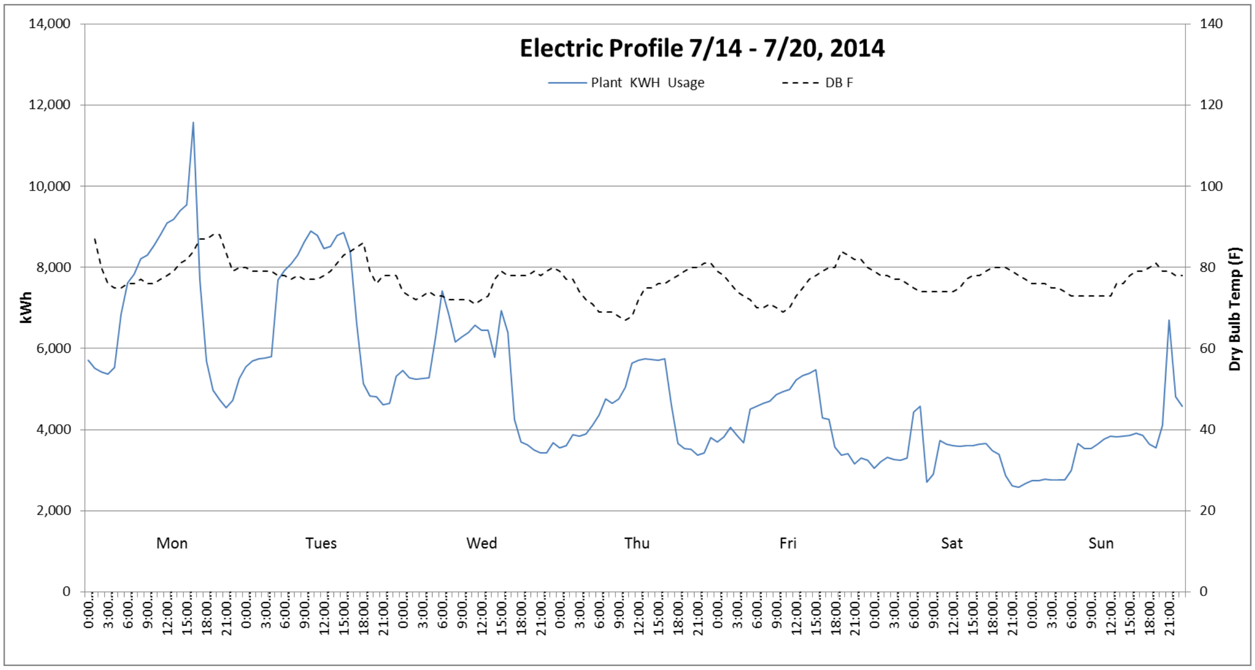

Figure 11 HOTD Electric Profile and Ambient Temperature, 7/14/14 - 7/20/14

Steam Plant

The HOTD steam plant consists of 5 boilers and one heat recovery steam generator driven with exhaust from the two on-site generators with a total nominal capacity to produce 1,570 thousand pounds per hour. The existing capacity is mainly based on the original coal boilers that have been converted to natural gas with oil as a backup fuel and as such the full capacity is not considered as reliable. While contiguous data for steam production and boiler gas use was not made available to allow efficiency calculations, a visual inspection of the plant and discussion with plant personnel suggests that the plant is well run and operates at a typical steam boiler plant efficiency of 80% with additional efficiency gains through utilization of economizers.

As data for the full year of 2014 is not complete, the steam data review period consists of the 12-month contiguous period for which data is available which runs from 10/1/14 through 9/30/15. For the 12-month review period, the total steam production was 1,901,649 thousand pounds (Mlb) with an average production of 217 Mlb and a peak production of 690 Mlb which occurred on February 20, 2015 at 8:00 AM. The annual load factor for the plant based on the peak demand of 690 Mlb is 31.5%.

Figure 12 provides a graph of the review period hourly steam production while Figure 13 provides hourly steam production and ambient temperature for December 2014. While temperature clearly has significant influence on load demand, as with cooling related electric loads, there is also a strong correlation between occupancy at the client buildings and load demand. In addition Figure 14 supports the appearance of a night and weekend setback operation at most of the client buildings with significant loads being placed on the system at 3 AM during week-days. In contrast to the cooling related electric diurnal variations, the heating loads appear to generally peak at 7:00 AM with demand subsiding until early afternoon when it levels off until 3 AM the following morning.

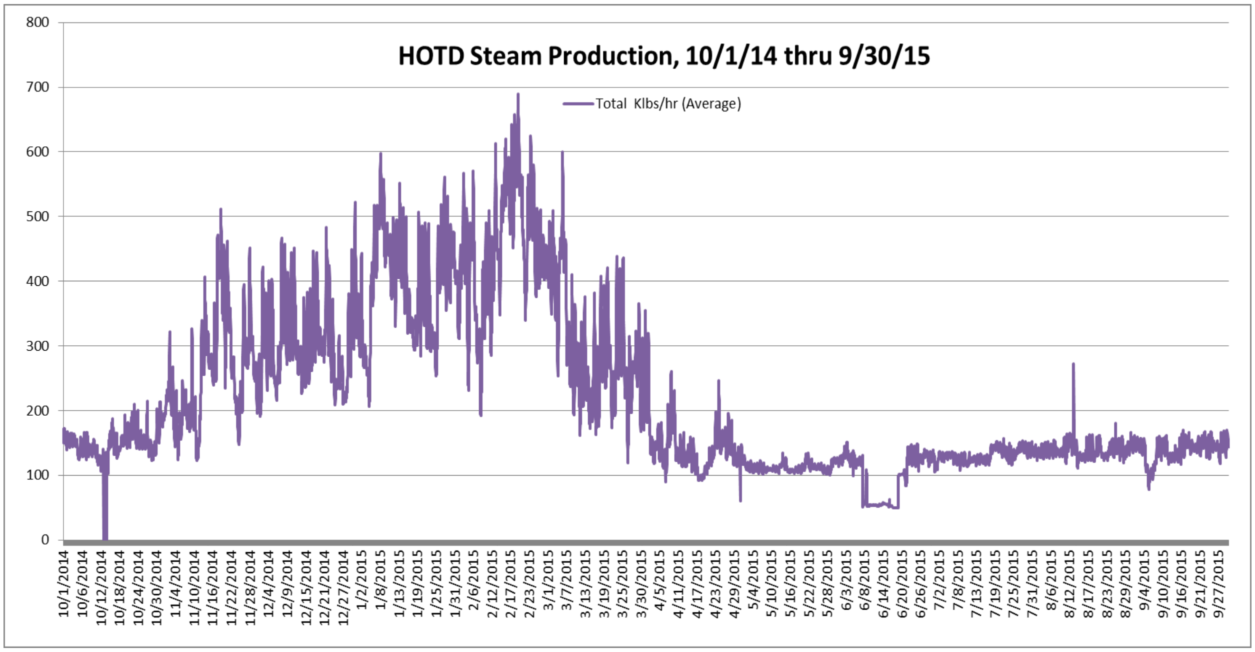

Figure 12 HOTD Steam Production, 10/1/14 through 9/30/15

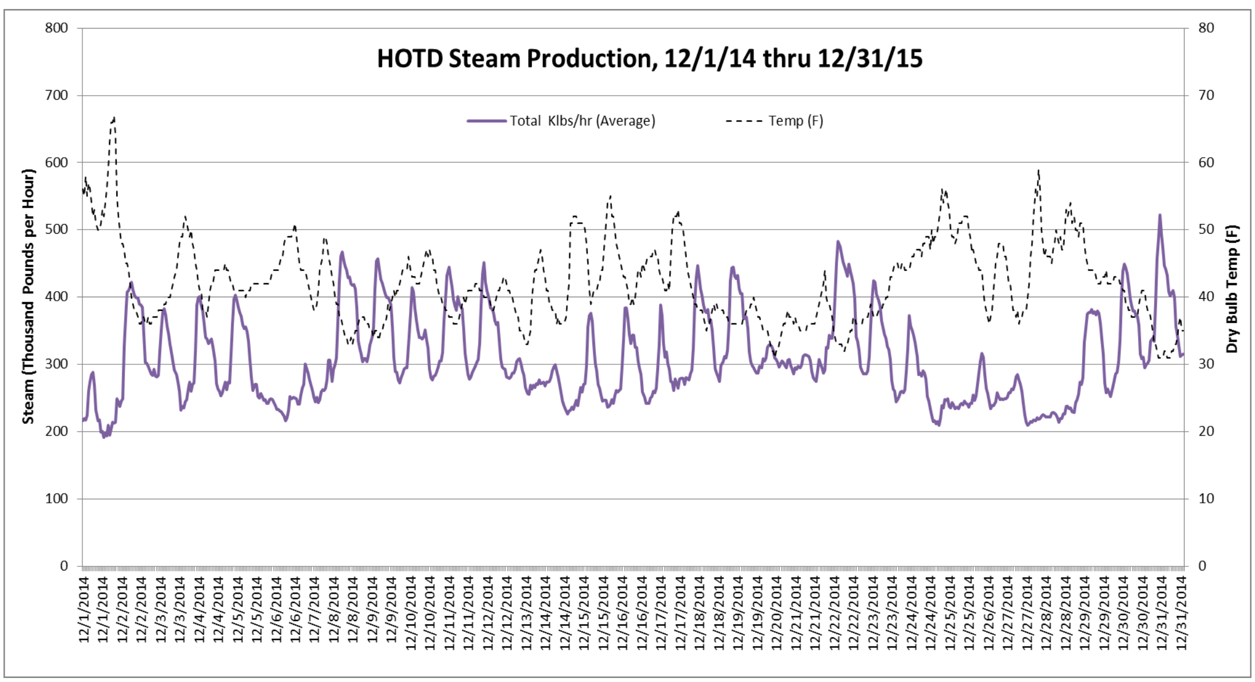

Figure 13 HOTD Steam Production and Ambient Temperature, December 2014

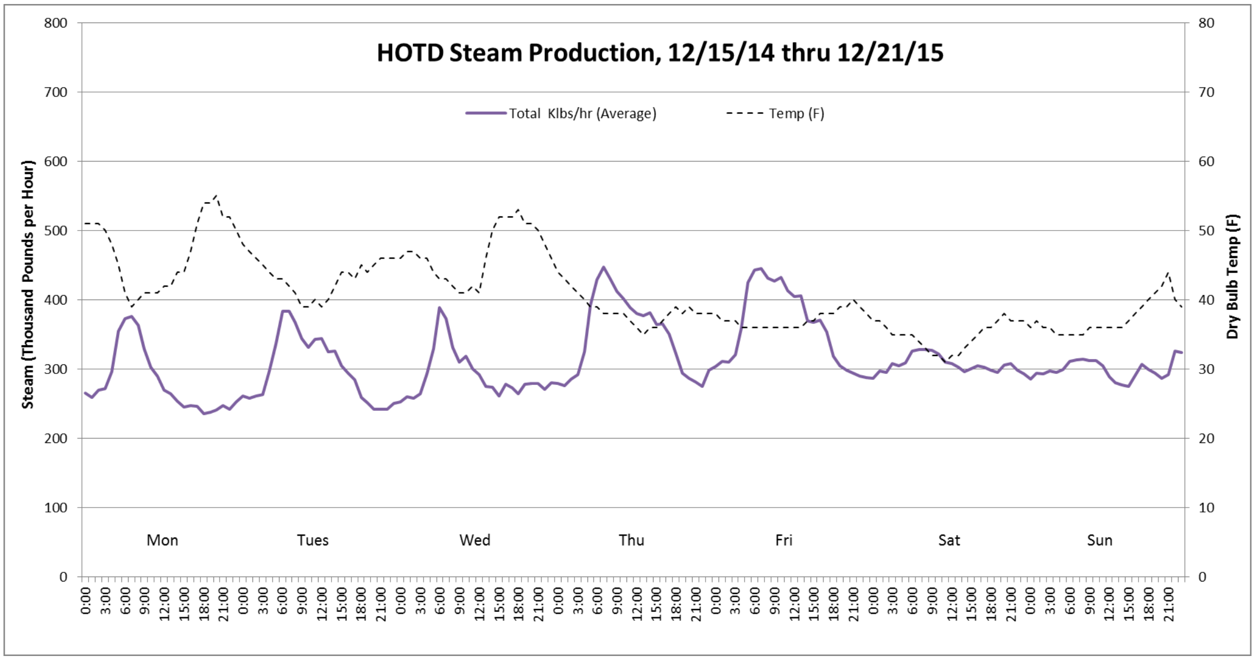

Figure 14 HOTD Steam Production and Ambient Temperature, 12/15/14 through 12/21/14

Chilled Water Plant

The existing chilled water plant consists of eight chillers with a total nominal capacity of approximately 17,000 tons. Six of the chillers are electric motor driven and two of the chillers are steam turbine driven. The chilled water plant consisting of chillers, cooling towers, distribution pumping and ancillary devices is the highest electric demand item within the HOTD plant.

While the monthly chilled water sales profile provided in Figure 4 exhibits a typical profile for space cooling, it does not describe the daily or hourly variations in chilled water usage which are necessary to properly understand the plant performance and capacity. Given that the summer electric demand is mainly driven by electric chiller demands to meet customer cooling requirements there is a correlation between power demand and cooling demand. Based on the total chilled water billing data and the hourly electric profile, and using a HOTD total plant base load of 750 kW and an overall chiller system efficiency of 0.85 kW per ton, Figure 15 provides a representative cooling profile that matches monthly total billing data. Figure 16 provides the estimated load for July 2014 together with the hourly ambient dry bulb temperature. This data again points to the major influence of occupancy at client buildings on load as well as the impact of night and weekend setback operation of many buildings. Based on the plant electric profile the above assumptions, the estimated total load in July was 3,985,965 ton-hours (92% of billing value), the peak demand was 13,205 tons, the average demand was 5,357 tons and the minimum demand was 1,864 tons. This calculates as a 41% load factor based on peak demand which is low for mid-summer and is mainly due to the customer operating profile. Again, this is not a reflection of the plant operation but rather a statement of client facility operation.

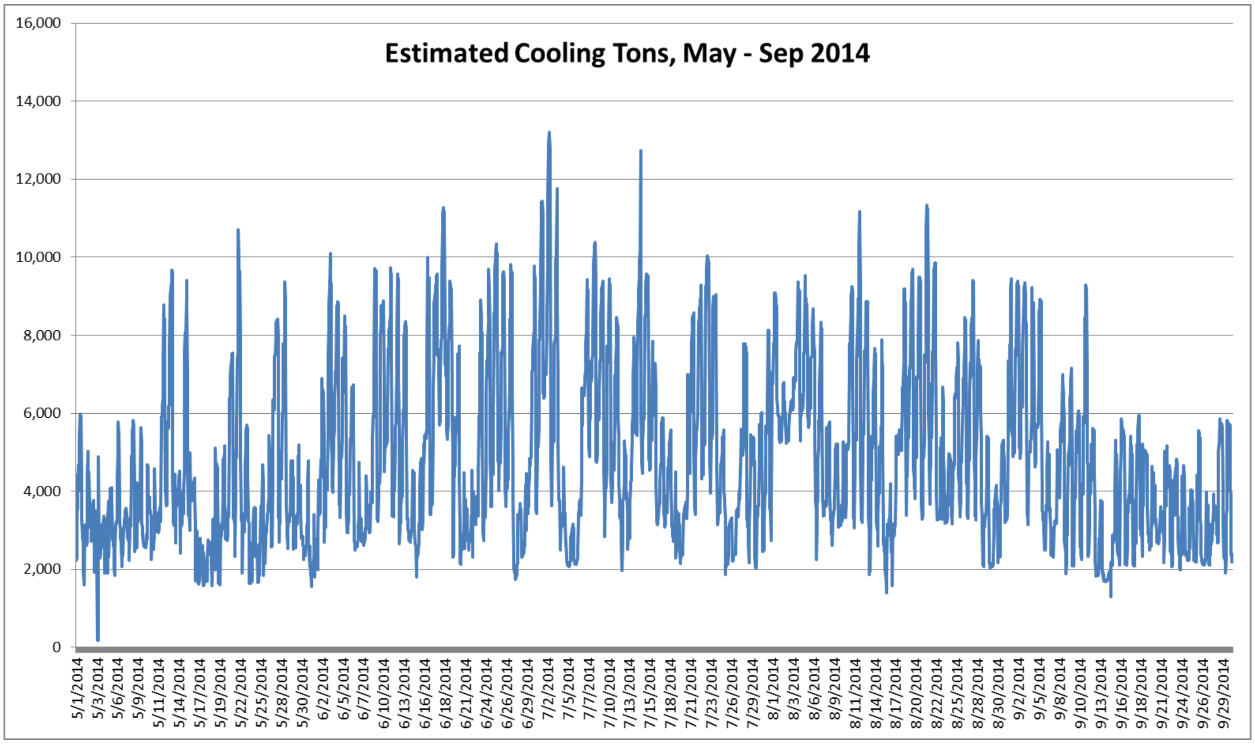

Figure 15 Estimated Cooling Load Profile in Tons per Hour, May through September 2014

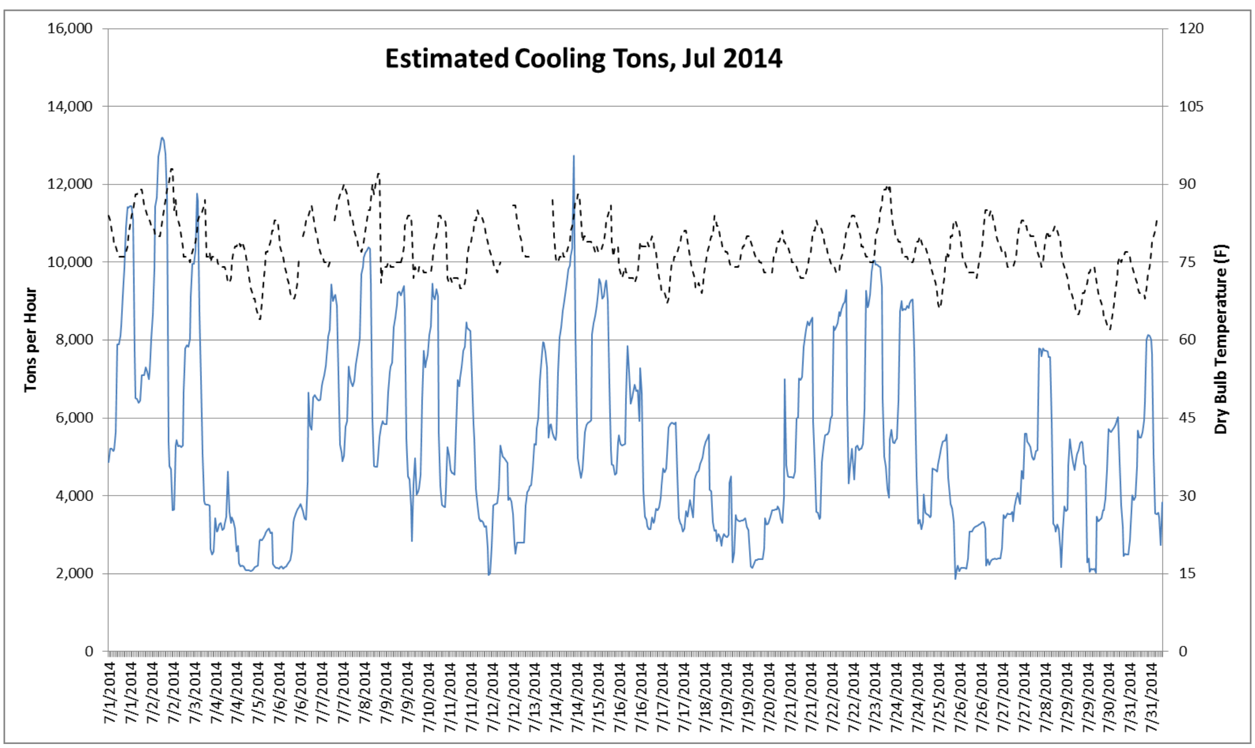

Figure 16 Estimated Hourly Cooling Load and Ambient Temperature, July 2014

CHP Plant

HOTD installed two 5.2 MW gas/oil combustion turbines that typically operate together during all available hours. Excess power that is not required by the plant is exported to PJM through the utility wires. Figure 17 provides a profile of the total on-site power produced by the CHP plant together with the total plant power consumption during 2014.

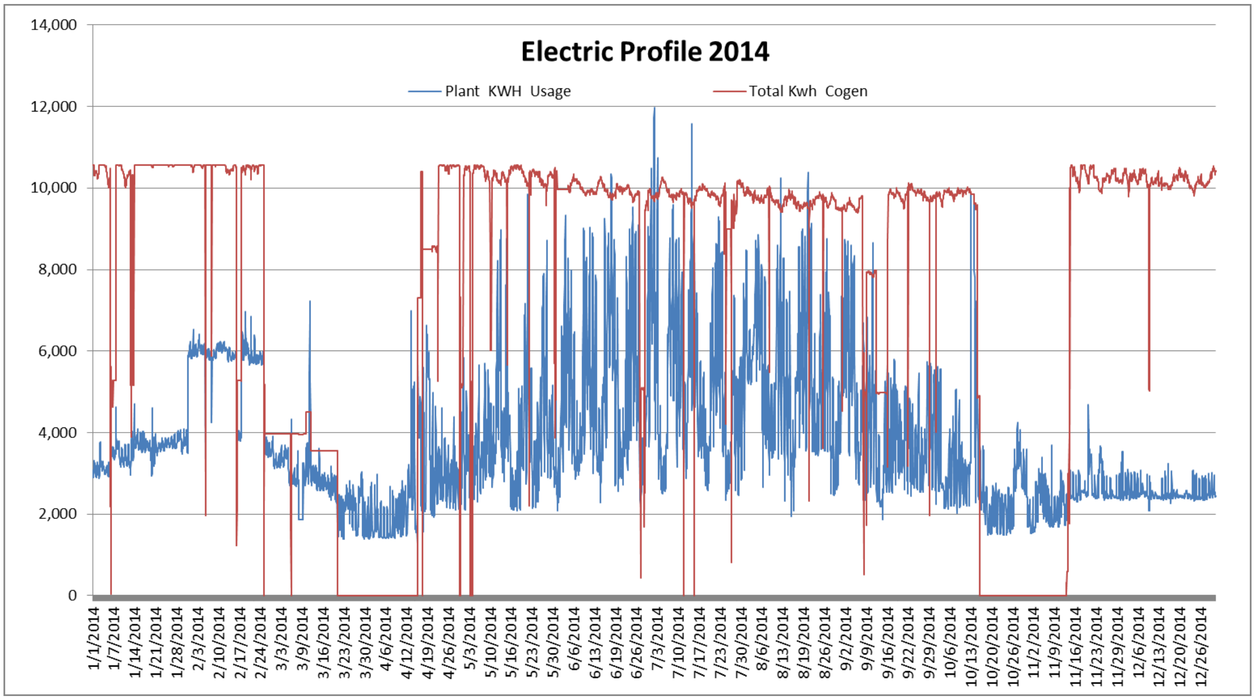

Figure 17 HOTD Plant CHP Power Generation and Total Plant Power Demand, 2014

During 2014 the CHP plant produced a total of 68,992,064 kWh of which 33,870,263 kWh was consumed internally resulting in an export of 38,186,708 of 55.3% of the plant's total production. Based on the data, the turbines were available 71% of the time which is significantly lower than the expected 95% to 97% availability typical for conbustion turbines. If the plant had an availability more inline with typical norms, then the percentage of exported power would significantly increase as a portion of output given that much of the down time was experienced outside of cooling season when internal plant power demand is low. If the CHP plant operated at 95% availability, it is extimated that the export volume would increase to 65% of CHP plant output. It is also noted that apart from the long-term maintenance related CHP plant outages, there were multiple short-term CHP plant outages which resulted in utility demand spikes in most months as shown in Figure 9 above.

Based on nominal specifications for the Solar Turbines 5.2 MW unit (Taurus 60), the electric efficiency is 28% higher heating vlaue (31% lower heating value) and the heat recovery to steam efficiency is 42% higher heating value. The high temperature exhaust produced by the turbines is directed to boiler #6 which acts as a heat recovery steam generator. At nominal conditions, the combined CHP units will produce approximately 52 million Btus for steam generation which is well below the approximately 100

Mlb per hour base load on the steam system during non-heating season, allowing the units to be fully thermally loaded during normal operation.

Given that the CHP plant can be thermally loaded whenever it is operational, the operating economics for exporting power are based on gas cost, maintenance cost and offset steam and power value. The offset steam value is estimated to be the cost of natural gas divided by a boiler efficiency of 80% while CHP system maintenance is assumed to be $0.01 per kWh. For the scenario where most of the power is exported, Table 4 provides a simple review of the net revenue associated with various export values for the portion of plant dedicated to export. It should be noted that 'net export value' is the total credit received for export sales and does not include any utility fees for access to the export mariket.

		Scenario A	Scenario B	Scenario C	Scenario D
Total Export	kWh	38,186,708	38,186,708	38,186,708	38,186,708
Net Export Value	**$/kWh**	**$0.030**	**$0.040**	**$0.050**	$0.040
Total Export Value	$	$1,145,601	$1,527,468	$1,909,335	$1,527,468
Fuel Input	MMBtu	462,601	462,601	462,601	462,601
Thermal Output	MMBtu	194,292	194,292	194,292	194,292
Fuel Cost		$4.50	$4.50	$4.50	**$6.00**
Total Fuel Cost		$2,081,705	$2,081,705	$2,081,705	$2,775,607
Steam Value		$1,092,895	$1,092,895	$1,092,895	$1,457,194
Maintenance Cost		$381,867	$381,867	$381,867	$381,867
Net Export Revenue		$(225,076)	$156,791	$538,658	$(172,812)

Table 4 Value of Power Export

Table 4 suggests that at the current typical monthly export rates of $0.03 to $0.04 per kWh and a natural gas cost of $4.50 per Decatherm, exporting power from the CHP plant does not produce any significant economic benefit and certainly does not contribute towards capital cost buy down. Only If the net export value was $0.05 per kWh, would the plant generate significant positive operating revenue, assuming a gas cost of $4.50 per Decatherm. If gas costs were $6.00 per Decatherm and net export value was $0.04 per kWh, the CHP plant would also lose revenue by exporting. Only when used to offset retail power purchases, or during months of market upset such as the polar vortex in January 2014 when wholesale electric prices are significantly higher, can the CHP plant generate net revenue.

Distribution System

Based on summary data provided, the total steam produced by the boiler plant during FY2015 was 1,901,649 while the total steam sales measured at the customers building was 1,249,868 which represents 65.7% of the total steam produced. Some of the steam produced is used to drive the existing steam turbine chillers which produce chilled water from steam. It is unknown how much of the steam is used to produce chilled water and how much steam is lost in the distribution system. Based on statements from facility personnel, the condensate return was 60% to 70% which is a very high percentage for such a large loop. The high rate of condensate return is an indication of good quality of the distribution system.

Strengths/weaknesses of current physical assets

Apart from the obvious age of the boiler plant and the significant maintenance effort and expense required to keep the boilers in operation, there appears to be no major weakness in the existing system. The strength of the existing HOTD plant is the facility personnel who have provided exceptional service in maintaining the current boiler plant operational despite its age. It is clear that HOTD contains a significant and very valuable knowledge base in relation to large steam/chiller plants and district energy distribution systems which is a valuable resource to GSA. While many plants of this age have been replaced, HOTD continues to provide highly reliable service with the existing 80-year old infrastructure.

Planned energy conservation measures including pump variable frequency drives (VFD), condensate return improvements, water harvesting, etc. will provide improved boiler and chiller system performance. Ultimately replacement of boiler stock and underground piping needs to be carried out if the plant is to maintain long-term operations.

SCOPE FOR IMPROVEMENT

As recognized throughout this report, the most significant improvements to plant operation are related to customer operating strategies. The customer base is not diverse with all major client loads operating in a similar fashion which is dominated by high occupancy during week day working hours. The cost of providing space conditioning to most of these facilities is high due to the relatively high ratio of peak to average load which requires high capacity be made available while average utilization is low. Figure 18 provides a view of steam load factor for all customers whose annual steam use exceeds 20 million pounds and indicates the relatively low load factor for most of the major customer base. Steam load factor is calculated as annual steam use divided by the maximum monthly use multiplied by 12 months.

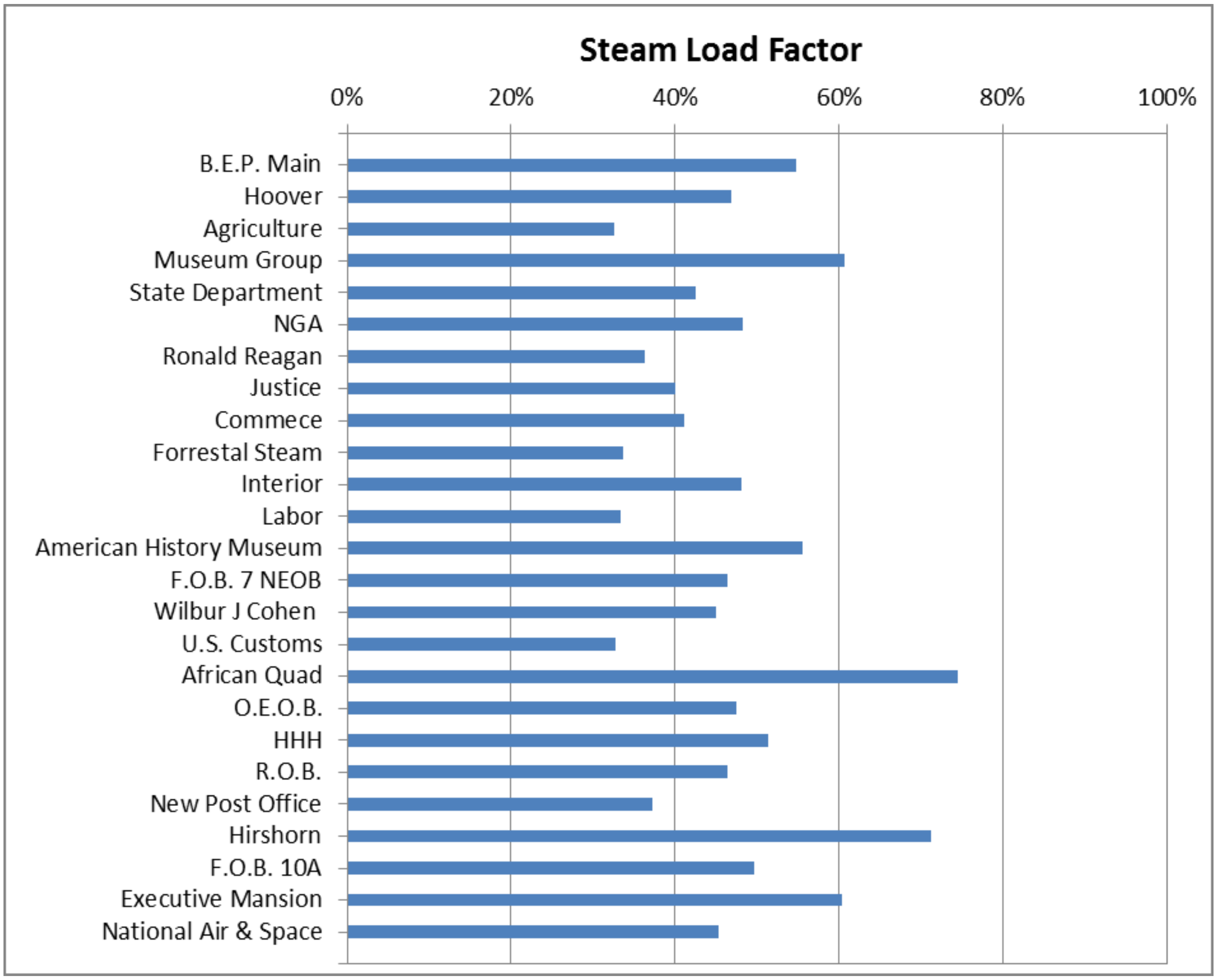

Figure 18 Monthly Steam Load Factor, FY2014

While these relatively low load factors are a burden on the HOTD plant cost base, they are typical for buildings with ‘9 to 5’ type schedules. However, it should be understood that such low load factors cause a high cost of service and will also make competitive on-site boiler plants equally costly. Improvement in communication with customers both in working with them to help improve load factor as well as understand the costly nature of their loads is needed. There may be opportunity with large clients to improve their operation schedule and a study relating night setback to cost of service should be undertaken. For customers such as the Department of Agriculture whose steam load factor as defined here is 33%, this means that if they were to consider implementing their own independent system, they would need a plant that is a minimum of 3 times bigger than their average load and in fact would more likely require a plant that is five to six times the average load in order to meet hourly peaks and maintain redundancy for reliability. In addition, comparisons with other district energy systems are not entirely valid as most of these other district systems serve a more diverse customer base including institutional facilities such as hospitals and multi-family residential facilities that significantly help to improve overall system load factor. HOTD is unique among typical district energy systems in that it serves commercial facilities only and includes no significant hospitals or residential type facilities.

Apart from replacement of the boiler plant with new boilers that would provide more reliable capacity, there are no significant efficiency improvements to be obtained from any upgrades to the existing boiler plant. It has been well maintained and operates at an acceptable efficiency but is well past its expected service life. Planned improvements to the condensate return system and replacement of buried piping will provide minimal operational improvements but are necessary in order to maintain reliability and current plant performance. Planned improvements such as adding VFDs to major pumps will generate savings on related costs but will have small impact on overall plant costs. Given the highly variable nature of customer loads, pump VFDs should provide significant savings on pumping costs as well as allow better control of customer loads.

Electric chillers are the major electric load at the facility with the chilled water system being responsible for approximately 80% of the facility peak power demand. It is apparent from the plant power demand profile (Figure 8) that power demand in summer is very peaky causing a higher cost for power delivery when the CHP plant is not operational (see imported power profile, Figure 9) as well as presenting a 'difficult' profile for either on-site power generation or 3rd-party purchases. Figure 19 shows the chilled water load factor for all customers and demonstrates that many customers have high variability in demand resulting in a high cost of service. Chilled water load factor is calculated as annual ton-hours use divided by the maximum monthly use multiplied by 12 months.

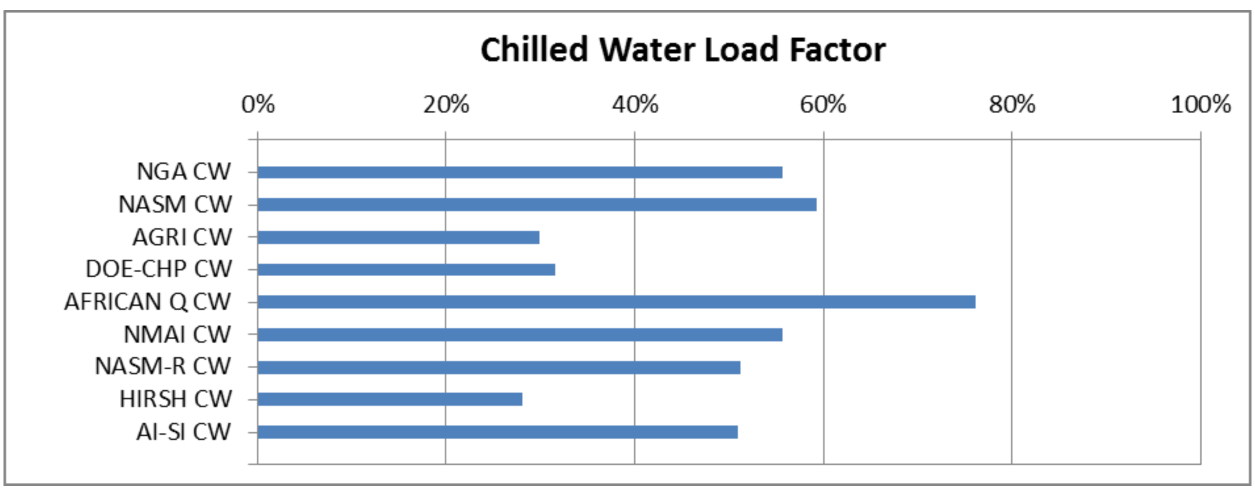

Figure 19 Monthly Chilled Water Load Factor

For both steam and chilled water customers, a study of specific usage patterns and demand profiles should be undertaken to identify high and low load factor clients. Results of this study would provide a better basis for customer charges than that currently used which is a flat rate for all customers. Customers with poor load factors could be assessed a capacity charge apart from an energy charge which would better represent the cost basis for each customer. Under this approach, high load factor clients would be charged less per unit of energy delivered while low load factor clients would be charged more per unit. This would also serve to provide a proactive defense against customer defections. Under the current scenario, high load factor clients (good customers) are subsidizing low load factor clients which creates an opportunity for defection of good customers. This sets up the potential for a 'death spiral' whereby loss of good customers results in the need for higher charges to remaining customers which encourages even bad customers to defect. The identification of customer loads and particularly for large customers with poor load factors will help make a sound business case on the need for the existing cost levels and give them a better basis for comparison of separate boiler/chiller plants.

While the site walk through indicated that the existing chillers were in good condition and well maintained, data was not obtained on chiller operating efficiencies. Given that the plant consists of 8 each approximately 2,000 ton chillers and that, except in non-cooling season the plant load is above 2000 tons, there is probably limited scope for addition of VFDs to improve plant performance. The plant could probably benefit from the addition of one or two VFD to designated 'peaker' chillers but otherwise chillers will operate at full load. While the addition of VFDs on the electric chillers generally improves plant performance, due to the short lived high load demands, it is expected that VFDs would have little impact on reducing monthly plant power demand. Depending on the future source of power and utility tariff, the low load factor of customer loads may mitigate much of the savings anticipated from the addition of VFDs if these savings are based on typical ASHRAE load profiles.

While the dispatch sequence for electric versus steam driven chillers is not known at this time, it is possible that better use of the steam turbine chillers could be made in order to mitigate the high electric demand for power at the facility. In the eventuality of the CHP system not being available, the steam turbine chillers would serve to reduce demand costs at the facility. As already stated, the current electric profile and resultant poor load factor increases the cost of electric delivery or on-site generation.

Another cost mitigation strategy is the addition of thermal energy storage – specifically chilled water storage. This would significantly help with reducing peak demands on the plant resulting in lower demand charges. Chilled water storage would have higher value in a scenario where all power was being imported from the utility.

As stated above, it is doubtful that the existing CHP plant provides any significant economic benefit since most of its output is exported to PJM at wholesale rates. In order for this plant to provide significant economic benefits, the output electric energy should be valued at retail rates rather than wholesale rates. The HOTD plant has an annual base load electric need of approximately 2.5 MW while the plant produces over 10 MW and even in summer when electric needs are highest due to electric cooling, the CHP plant still exports much of its output. Based on July 2014 calendar month data, the CHP plant produced 7,216,307 kWh of which 3,946,070 kWh was used internally and 3,270,237 or 45% was exported. While the steam output from the CHP plant can be used all operating hours, the export at wholesale value of most of the electric energy severely undercuts the economics of the plant. Other than providing a resiliency option for the plant which currently has no additional value, unless a way is found to obtain retail value for most of the plant output, there is no expectation that the existing CHP plant would actually provide significant energy cost savings. Given the nature of combustion turbines, the plant cannot be varied with internal load so that the best operating strategy may be to operate only one of the CHP plants from mid-April to mid-October and stop running the full plant to provide export.

In all scenarios, the HOTD plant should consider equipment dispatch based on expected load conditions, ISO peak demand schedule, wholesale market power costs and hourly utility tariff rates. It is unknown if the plant has implemented a dispatch sequencing program but if not, this should be investigated. Given the high demand during PJM peak hours, the existence of on-site generation and the availability of steam driven chillers, there may be good opportunity for HOTD to use equipment to manage grid load rather than operate CHP all the time and reacting only to customer load. As demonstrated in Figure 20, while the CHP plant did operate most of the time, it did not succeed in reducing annual plant demand from the grid by as much as would have been expected. The peak plant demand in 2014 was 11,974 kW without CHP and the actual grid demand with CHP was 8,591 kW. Operating only one CHP unit at the time and alternating between plants during service intervals may provide improved reliability with resulting reduced annual plant demand and better economics.

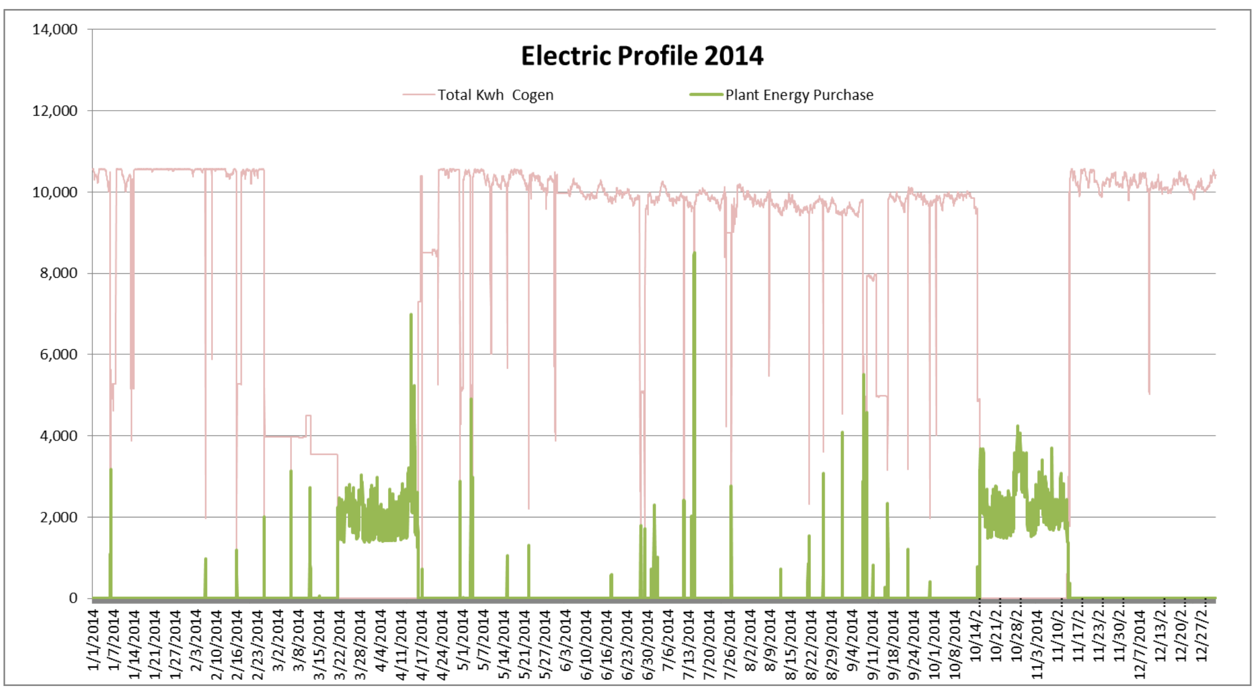

Figure 20 CHP Plant Output and Plant Import Profiles

Another approach may be to provide existing thermal customers with electric power and sell this power at retail rates. The ability to offset utility purchases at a separate facility is typically not allowed according to utility regulations but there may be some opportunity to explore this avenue. If CHP power could be sent to existing clients such as the Department of Agriculture for example, at $0.09 per kWh, it could result in adding annual revenue of $1.5MM to the operation. In order for this approach to be feasible, the regulatory environment needs to allow supply of energy to existing thermal customers. It is also assumed that the existing thermal tunnels could be used to run the electric connection. This approach would also provide a higher level of resiliency to the customer site that they currently have. If the utility were amenable or if regulations could be made to allow wheeling of power, net metering or direct energy supply, there should be sufficient room in the current retail rates to allow some revenue flow to the utility.

Alternatively, if electric energy sales were not allowed, supply of emergency only capacity may be an option that would help generate revenue from the existing plant. In this scenario, energy from the CHP plant would only be provided to the customer site if the utility were unavailable. While this would not require full operation of the CHP plant, it could provide additional revenue to HOTD. It should also be noted that if the CHP plant is configured to black start and given that it has the capacity to meet HOTD's peak electric demand (with some minor curtailment in peak summer), in the event of a long term utility outage HOTD can provide resilient power heating and cooling to its customer base. This HOTD advantage is currently not marketed as a 'bonus' feature for the customer base.

Given the relatively small footprint taken by the HOTD plant and the nature of existing buildings, it is thought that there is little opportunity to develop any significant amount of solar PV at the site.

While the steam header operates at 250 psig, the boiler plant is rated for 400 psig and an opportunity may exist to integrate a back-pressure steam turbine generator that would take the high pressure steam from the boilers and reduce it to 250 psig and produce electric power in the process. Based on existing steam flow rates, a steam turbine generator may be able to meet most or all of the internal plant electric needs in winter and provide approximately 1 MW of power in summer when steam flow rates are lowest. The ability to reduce the header pressure requirements would facilitate such a project and turbine output should be dedicated to internal use only without power export.

The HOTD plant incorporates a center of excellence for steam and chiller plant operations. This is currently provided to GSA as well as many system clients at no additional charge. In order to properly account for these costs, a separate engineering cost center should be considered. While most existing thermal clients will expect this service to be embedded in their energy cost, costs related to non-thermal energy clients such as GSA facilities outside the loop should be separated out as a non-energy related cost. While it is encouraged that this engineering service be maintained and is of high value it most probably should be identified as a cost center separate from the energy rates.

COG and its member governments and other stakeholders in the National Capital Region (NCR) are currently evaluating the feasibility of advanced microgrid systems in different facilities in the National Capital region. This will cover the engineering and financial feasibility of advanced microgrid system options, and to evaluate and optimize design and operational plans

Since heating and cooling loads will constitute bulk of the energy demand in many of these facilities, any microgrid solution will have to address this in addition to other electrical loads. This provides an opportunity to HOTD to position itself at the center of these efforts as a key provider of reliable supplier of steam and chilled water to these facilities. Having a reliable supplier/solution for meeting heating and cooling loads will drastically reduce the size, complexity and cost of such microgrids making them economically viable

Another opportunity could be the formation of a cluster microgrid comprising HOTD and adjoining facilities like department of agriculture. In this configuration HOTD could also become the provider of electricity to these facilities in addition to steam and chilled water. If regulatory constraints could be overcome this approach would significantly help make these microgrids economically viable instead of setting up large captive generation in each and every facility

DER-CAM MODEL SUPPORT

The Distributed Energy Resources Customer Adoption Model (DER-CAM) is a techno-economic optimization tool that delivers holistic decision support of the deployment and operation of distributed energy systems, including district energy systems of the scale of HOTD [6]. DER-CAM was initially developed for analysis of cogeneration systems. Relevant technology models such as thermal storage [7,8] and district energy systems [9] have been added to model and validated. These models allow for a detailed representation of the HOTD system to be examined in detail. We suggest modelling the current HOTD operations using DER-CAM to evaluate the potential for improvement under the following scenarios:

Scenario A: Intelligent dispatch of resources through real time optimization software

Utilities normally schedule and dispatch their different resources based on demand and supply to achieve minimum cost of operation. This process is called unit commitment and economic dispatch. Current operations and energy purchasing strategies are essentially based on manual control without real-time reference to customer loads, distribution utility tariff schedules or wholesale market conditions. This can be automated using intelligent energy management software like DER-CAM Operations from LBNL. Modelling of the base case scenario using DER-CAM Planning can help identify potential for improvement prior to actual implementation of the system.

Scenario B: Improving capacity utilization through addition of customers with different load profiles such as hospitals, multi-family residential or hotels.

One of the key issues affecting economic operation of HOTD is the poor load factor of its client operations due to its customer profile being predominantly large office or commercial facilities with few or no institutional type clients. Existing facilities have high demand during the day with low demand at night and during weekends. This situation could be improved if HOTD is able to serve a more diverse customer profile. DER-CAM modelling of this scenario with varying levels of diversity should help validate this assumption and quantify its impact.

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Lawrence Berkeley National Laboratory

One Cyclotron Road | Berkeley, California 94720

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