STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. __________

DIRECT TESTIMONY
OF
DANIEL HANSEN

VICE PRESIDENT, CHRISTENSEN ASSOCIATES
ENERGY CONSULTING, LLC

January 12, 2018
P-10

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
DANIEL HANSEN

VICE PRESIDENT, CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

I. INTRODUCTION AND PURPOSE OF THE TESTIMONY

Q. Please state your name, affiliation and business address.

A. My name is Daniel Hansen and I am a Vice President at Christensen Associates Energy Consulting, LLC. My principal place of business is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705. My credentials are set forth in the attached Schedule DGH-1.

Q. Please describe your involvement in this proceeding.

A. I have been retained by Public Service Electric and Gas Company ("PSE&G" or "the Company") to assist them in developing and supporting their Green Enabling Mechanism ("GEM") proposal. The GEM aligns utility and customer incentives to promote conservation and energy efficiency.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to introduce and support PSE&G's proposed GEM.

II. THE PURPOSE OF PSE&G'S PROPOSED GREEN ENABLING MECHANISM

Q. What is the purpose of PSE&G's proposed GEM?

A**.** The GEM is intended to remove the disincentive to promote conservation and energy efficiency that PSE&G faces because of its retail distribution rate designs. Specifically, PSE&G recovers its distribution costs through a combination of fixed service charges (*i.e.*, \$/month), volumetric energy rates (*i.e.*, \$/kWh or \$/Therm), and demand charges (*i.e.*, \$/kW or \$/Demand Therm). These rates are set periodically, typically in a rate case, to collect a specific amount of revenue (the revenue requirements) based on an agreed-upon test year number of customers and weather-normalized sales and/or demands from those customers. Actual revenues recorded by PSE&G will vary as the number of customers and their usage varies from the values used to set rates. When customers reduce their energy use or demand, PSE&G experiences a reduction in revenue that is not matched by a reduction in distribution costs. Consequently, PSE&G currently has a disincentive to encourage customers to reduce usage.

The GEM would remove this disincentive by creating a deferral tracking account in which the difference between allowed and actual distribution revenue is recorded. Allowed revenue will be determined in this rate case proceeding and is reflective of each customer class's allocated cost of service. As explained in detail later in my testimony, the GEM will establish the monthly amount of total allowed revenue ("GEM revenue") by multiplying the per-customer allowed revenue by the actual number of customers served in the current month. The difference between the GEM revenue and actual distribution revenue from customers will be booked to a GEM deferral account. Over-recovery of allowed revenue (when GEM revenues are lower than actual revenues) results in a rate decrease in a future period. Conversely, under-recovery of allowed revenues (when GEM revenues are higher than actual revenues) results in a rate increase in a future period. Through these rate adjustments, the GEM would make PSE&G indifferent to its customers' consumption decisions.

Q. Why is it important to remove PSE&G's disincentive to promote conservation and energy efficiency?

A**.** By removing PSE&G's disincentive to promote conservation and energy efficiency, the GEM helps align the interests of the Company and its ratepayers. This is particularly relevant given PSE&G's intention to implement a large set of energy efficiency programs. PSE&G's interest in implementing and successfully running energy efficiency programs, like any other utility recovering fixed costs through volumetric rates, is affected by a conflict between the success of those programs and the resulting detriment to the Company's financial health.

Q. Is there any evidence that mechanisms like the GEM are associated with improved conservation and energy efficiency outcomes?

A**.** Yes, two recent articles have discussed the relationship between revenue decoupling (the generic term for mechanisms such as the GEM) and electric energy efficiency. First, an article in *The Electricity Journal* examined five decoupled utilities (Idaho Power Company, Portland General Electric, Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison), concluding "In each instance, the utility significantly increased both its efficiency program spending and its energy savings in the years following adoption of decoupling."[1]

[1] Nissen, Will and Samantha Williams. "The link between decoupling and success in utility-led energy efficiency." *The Electricity Journal*, 29 (2016) 59-65.

Second, an article in *The Energy Journal* analyzed data from January 2001 through December 2010 and found that "decoupling is historically associated with significant residential electricity consumption reductions, augmented DSM [Demand Side Management] spending levels, and increased DSM investment efficacy."[2]

Q. Is there any related evidence in favor of applying revenue decoupling to natural gas utilities?

A. Yes, I conducted two independent evaluations (conducted on behalf of all stakeholders[3]) of natural gas revenue decoupling mechanisms. The first evaluation was of Northwest Natural Gas's mechanism,[4] while the second evaluation covered the Conservation Incentive Programs ("CIPs") in place at both South Jersey Gas and New Jersey Natural Gas.[5] For all three utilities, I concluded that the mechanism should be continued, in part because changes in utility behavior were consistent with the incentive changes decoupling is intended to produce.

Q. Would the GEM reduce the Company's incentive to operate efficiently?

A. No, the GEM would not reduce PSE&G's incentive to operate efficiently. The GEM affects only the distribution revenue collected from applicable customers. It does not affect cost levels or guarantee a rate of return. The benefits the Company can expect to realize from operating efficiently are not changed by implementing the GEM.

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[2] Kahn-Lang, Jenya. "Effects of Electric Utility Decoupling on Energy Efficiency." *The Energy Journal*, Vol. 37, No. 4, pp. 297-314, 2016.

[3] Both evaluations were required by the order approving the mechanism. While the utilities paid for the evaluations, they were independently conducted with input from all stakeholders.

[4] "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural." March 2005.

[5] "An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas." March 2009.

Q. Would the GEM reduce a customer's incentive to conserve?

A**.** No. With the GEM in place, a customer who is evaluating whether to engage in a conservation activity can expect an immediate benefit that is the same as it would have obtained under standard rates. That is, the customer can expect a bill reduction in the amount of the full volumetric rate, including the commodity cost and all riders and fees, multiplied by the amount of saved energy (*i.e.*, kWh or Therms). The portion of this bill reduction that is associated with distribution revenues is then placed in the GEM deferral account for the utility to recover in the following year. Because each customer uses a very small percentage of the total group-level usage, a conserving customer pays back essentially none of its own lost revenues. Therefore, a customer's decision to conserve should not be affected by the presence of the GEM because the customer cannot conserve enough energy to affect the rate it pays in the following year.

Q. Have other regulators acknowledged that decoupling does not affect a customer's incentive to conserve?

A**.** Yes. The Oregon Public Utility Commission concluded that decoupling does not affect customer incentive to conserve in Order No. 09-020 for Docket UE-197,[6] which approved the Sales Normalization Adjustment, or SNA, for Portland General Electric. The order stated the following:

> Staff also argues that the SNA would create a disincentive for customers to improve their energy efficiency because the SNA would increase rates and reduce the bill savings. We believe that the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient. (Page 28)

[6] http://apps.puc.state.or.us/orders/2009ords/09-020.pdf.

Q. Have other organizations preferred decoupling to alternatives because it does not reduce a customer's incentive to conserve?

A**.** Yes. The Natural Resources Defense Council ("NRDC") has supported revenue decoupling as a means of addressing utility disincentives to promote conservation because decoupling preserves the customer's incentive to conserve.[7]

III. <u>PSE&G'S PROPOSED GREEN ENABLING MECHANISM</u>

Q. What topics will you address in this section?

A**.** In this section of my testimony, I provide a detailed description of PSE&G's proposed GEM.

Q. At a conceptual level, how would the proposed GEM function?

A**.** In the proposed GEM, PSE&G records the monthly difference between allowed, or "GEM revenue," and actual revenue for each of the applicable customer classes. This difference is called the "GEM deferral." These deferrals are accumulated for 12 consecutive months, at which point the annual total is divided by forecast sales to the customer class for the following year to calculate the Green Enabling Charge or Credit ("GEC"). When GEM revenue is less than actual revenue, customers receive a rate decrease or credit in the following year. When GEM revenue exceeds actual revenue, customers receive a rate increase or charge in the following year. The GEM deferral will include the effects of weather (*i.e.*, allowed revenue is based on weather-normalized test-year revenues while actual revenue fluctuates with weather conditions). As described below, total GEM revenue scales with the number of customers served.

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[7] Energy Facts: Removing Disincentives to Utility Energy Efficiency Efforts. https://www.nrdc.org/sites/default/files/decoupling-utility-energy.pdf.

Q. How would the proposed GEM affect the total amount of revenue from distribution base rates?

A**.** As discussed earlier in my testimony, through regulatory proceedings, PSE&G establishes rates to collect a specific amount of revenue from customers (the utility's revenue requirement) based on the test-year number of customers and energy usage (volumes and demand) by those customers (referred to as "billing determinants"). Currently, the actual revenue PSE&G records varies from the revenue requirement set in the last rate proceeding due to both changes in the number of customers served and their energy use. Changes in energy use may be due to variability in weather, increases in appliance and home energy efficiency, and variations in economic conditions in and around PSE&G's service territory. PSE&G's GEM proposal is to record the difference between actual revenues and GEM revenues, which are a product of allowed revenue per customer (to be established in this base rate case proceeding and adjusted in future rate proceedings) and the actual number of customer served. By recovering or refunding the difference between GEM revenue and actual revenue, the GEM eliminates the variability in revenue due to variations in customer usage levels, regardless of the cause, but retains variability in revenue due to the number of customers served. Because the GEM severs the link between PSE&G's sales and revenues that exists via its rate designs, the GEM removes PSE&G's disincentive to promote conservation and energy efficiency. In addition, the GEM removes PSE&G's incentive to *increase* usage per customer.

Q. How will GEM deferrals be calculated?

A**.** Each month, PSE&G will compare GEM revenue and actual revenue from distribution base rates, with the difference entered in the GEM deferral account. The calculation of the deferral for customer group g in month m ($Deferral_{m,g}$) is shown in Equation 1. The equation has the same form regardless of the service (gas or electric) or customer class to which it is applied; only the parameter values (*e.g.*, the allowed revenue per customer) change when the GEM is applied to different customer classes.

Equation 1: $Deferral_{m,g} = C_{m,g} \text{ x } Allowed\ RPC_{m,g} - Actual\ Revenue_{m,g}$

where

$C_{m,g}$ = The number of customers served for customer class g served during month m.

$Allowed\ RPC_{m,g}$ = The allowed weather-normalized revenue per customer for customer class g served during month m, as determined each time base rates change, based on the revenue requirements and billing determinants established in each proceeding.

$Actual\ Revenue_{m,g}$ = The distribution base rate revenue booked to customer class g served during month m.

The first term of Equation 1, $C_{m,g}$ x $Allowed\ RPC_{m,g}$, represents the total allowed revenue under the GEM, or GEM revenue, calculated as the allowed revenue per customer multiplied by the number of customers currently served during month m for customer class g. This term shows that total allowed revenue changes with the number of customers served. The second term of Equation 1 ($Actual\ Revenue_{m,g}$) is the revenue booked from the base rates during month m for customer class g. GEM deferrals (whether positive or negative) will earn interest, with the applicable rate being the 2-year U.S. Treasury rate plus 60 basis points. The interest rate will reset based on the current method for PSE&G's Universal Service Fund rate, specifically resetting each month using the 2-year Treasury rate as of the first business day of the month. Because the $Allowed\ RPC_{m,g}$ values are based on weather-normalized usage while the $Actual\ Revenue_{m,g}$ includes the impacts of weather, the resulting GEM deferral will include the effect of weather on revenue. That is, the GEM weather normalizes PSE&G's distribution revenue, and also adjusts for any other factors that result in a change in usage per customer versus the test-year usage per customer used in setting the base rates.

Q. How will PSE&G determine the value of $C_{m,g}$, or the number of customers served?

A. The value of $C_{m,g}$ is based on the number of full-month customers, which is calculated as the service charge revenue divided by the service charge rate. This definition is used in place of the number of customers billed, which can include more than one customer for the same meter in a given month due to move outs/move ins. Customers that move out/move in during a billing cycle receive a prorated service charge, which is reflected in PSE&G's service charge revenues. Therefore, PSE&G's proposal to use the number of full-month customers provides an accurate number of meters receiving service for the month and prevents double counting of customer premises in the calculation of allowed revenue.

Q. How will PSE&G determine the values for *Allowed* $RPC_{m,g}$, or the allowed revenue per customer?

A. The *Allowed* $RPC_{m,g}$ values will be based on the distribution revenues and full-month number of customers established through this rate case in each customer class. That is, the same inputs used to calculate the Delivery Charges through this proceeding will be used to calculate the RPC values. Each month's RPC is calculated as that month's allocated revenue requirement divided by the test-year number of customers in the class for that month. The resulting values will reflect the pattern of RPC across months, such as the fact that electric RS customers have higher RPC during summer months than in winter months. For those customers, if the GEM used a single RPC value across the whole year in place of the proposed month-specific values, it would tend to produce refunds during summer months (when GEM revenue would tend to be less than actual revenue) and charges during winter months (when GEM revenue would tend to exceed actual revenue). The use of monthly RPC values results in GEM revenue values that better reflect the actual revenue for PSE&G each month. Schedules DGH-2E and DGH-2G (for electric and gas service, respectively) contain an example of PSE&G's RPC calculations for each customer class and month of year, including the underlying data. The data submitted is based on current rates and test-year billing determinants. Note that the RPC values will be updated whenever base rates change (*e.g.*, at the conclusion of this rate case, due to infrastructure programs, and subsequent rate cases), as illustrated in Schedules DGH-3E and DGH-3G.

Q. Can you provide simple examples of how the calculations outlined above would work?

A**.** Yes. Let's assume that through a rate case PSE&G establishes that it needs to collect $1,300 from 10 customers with a fixed service charge of $10 per customer per year, or $100 in total per year. The remaining $1,200 will be collected from sales volumes, or $120 per customer. Assuming sales to each customer is 2,400 kWh during the test year, the rate to collect the $1,200 will be $0.05 per kWh ($1,200 / (10 customers x 2,400 kWh)). The RPC in this example is $130 ($1,300 / 10 customers, which can also be calculated from the rates as $10 per year + $0.05 x 2,400 kWh).

Suppose that in the year after the rate case, the number of customers stays at 10 and use per customer increases to 2,500 kWh. Actual revenues for the year will be $1,350, which is $100 from the service charge plus $1,250 from energy sales (2,500kWh/customer x

$0.05/kWh x 10 customers). Under current ratemaking methods (in the absence of the GEM), PSE&G would gain $50 compared to the revenues set in the rate case due to increase in sales.

In contrast, under the GEM the $50 gain would be refunded to customers in the following year. That is, actual revenue would still be $1,350, but the GEM revenue would be $1,300 (the $130 RPC multiplied by the 10 customers served). PSE&G would record a deferral of ($50) for the year and give it back to customers in the following year through a rate decrease (of $50 divided by the expected sales during the year).

The previous example shows what happens when sales increase but the number of customers served stays the same. Now suppose that the number of customers served increases, but use per customer remains the same. Specifically, the number of customers served increases by 1 and use per customer remains 2,400 kWh. Actual revenue would be $1,430, with $110 in service charge revenue and $1,320 in sales revenue (2,400 kWh/customer x $0.05/kWh x 11 customers). Without the GEM, PSE&G would gain $130 compared to the rate case. With the GEM in place, GEM revenue would be $1,430 (11 customers times $130 RPC), which exactly matches the actual revenue. Thus, there would be no GEM deferral for that year. The general point from these examples is that the GEM will only affect Company revenue due to changes in use per customer. If the only thing that changes relative to the test year is the number of customers served, the GEM will have no effect.

Q. How would the proposed GEM deferral be converted to a charge or credit?

A. Every twelve months, the cumulative GEM deferral for each customer group would be converted to a dollar-per-kWh (for electric service) or dollar-per-therm (for gas service) charge or credit (the GEC) by dividing the deferral amount by the annual forecasted sales to the customer group. A positive cumulative deferral would result in a charge while a negative cumulative deferral would result in a credit. Separate GEC calculations will be made for each affected customer class, which prevents the GEM from causing inter-class cross-subsidies. Schedules DGH-4E and DGH-4G provide examples of the deferral calculation and Schedules DGH-5E and DGH-5G show the associated calculations of the GEC. Schedules DGH-6E and DGH-6G provide details on the deferral interest calculations.

Q. What would be the typical reason for the GEC to be a charge or a credit?

A. The primary purpose of the GEM is to remove the Company's disincentive to promote conservation and energy efficiency. If it is successful in doing so, I would expect the GEM to produce charges on average. These charges would reflect recovery of the reduced revenue from conservation. The effect of weather on customer usage could lead to a charge or credit in a given year. Mild weather (reducing sales from cooling or heating) would tend to produce charges, while severe whether (especially hot summers or cold winters) would produce credits.

Q. What administrative schedule does PSE&G propose for the GEM?

A. For electric service, the proposed administrative schedule for the GEM aligns with the timing of the annual BGS rate adjustments. Specifically, GEM deferrals will be calculated from January through December. PSE&G will file the deferral-induced rate adjustment by the following March 1st with the resulting rates going into effect on June 1st. The rate adjustment will be in place from June 1st through the following May 31st.

For gas service, the proposed administrative schedule for the GEM aligns with the timing of the typical annual BGSS rate adjustment. Specifically, GEM deferrals will be calculated from May through April. PSE&G will file the deferral-induced rate adjustment by the following July 1st with the resulting rates going into effect on October 1st. The rate adjustment will be in place from October 1st through the following September 30th.

PSE&G will implement the GEM when new rates from the rate case go in effect, which may result in the first-year deferral beginning prior to or after January 2019 for electric and May 2019 for gas.

Q. What portion of the electric and gas rates will be included in the GEM?

A**.** The GEM only applies to revenue collected from the following Delivery Charges: Service Charge, Distribution Demand Charges (per peak kilowatt or average therm), and Distribution Volumetric Charges (per kilowatt-hour or therm). It does not apply to any supply charges or non-base rate charges such as the Social Benefits Charge, Solar Pilot Recovery Charge, Green Programs Recovery Charge, or the Margin Adjustment Charge.

Q. How does the GEM relate to PSE&G's current Weather Normalization Charge ("WNC")?

A**.** As described above, the allowed revenue per customer is calculated using weather normalized billing determinants. Since the GEM will defer the difference between actual revenues and the weather-normalized GEM revenues, the deferral will include the effects of weather (*i.e.*, all else equal, if it's a colder than normal winter and therm sales increase, customers will receive a credit because actual revenues will be higher than GEM revenues,). Because the impacts of weather are included in the GEM, the WNC deferral calculation would be suspended once the GEM is in effect. The collection/credit of the WNC deferred balance through the tariff would continue until the balance is close to $0. Any small remaining balances will be rolled into the GEM. Also, as discussed later in my testimony, the GEM continues the customer protections established in the WNC, namely through a cap on bill increases and an earnings test.

Q. What are the applicable electric service classes for the GEM?

A**.** The GEM will apply to the following electric service classes, comprising four distinct groups:

- Residential customer classes: those taking service on the Residential Service ("RS") and Residential Heating Service ("RHS") rates;
- Residential Time-of-Use ("TOU") customers: those taking service on the Residential Load Management Service ("RLM") rate;
- General Light and Power Service Measured Demand and Estimated Demand ("GLPMDED") customers; and
- Large Power and Lighting Service customers served at secondary distribution voltages ("LPL-S").

The GEM excludes all other customers, including: General Light and Power Traffic and Signal (GLPTS) customers, General Light and Power Night Use (GLPNU) customers, Large Power and Lighting Service customers served at primary voltage ("LPL-P"), High Tension Service ("HTS") customers, Water Heating Service ("WH") customers, Water Heating

Storage Service (“WHS”) customers, Building Heating Service (“HS”) customers, and all street lighting customers.

Q. What are the applicable gas service classes for the GEM?

A**.** The GEM will apply to the following gas service classes, comprising three distinct groups:

- Residential customer classes: Residential Service (“RSG”), including heating (“RSGH”) and non-heating (“RSGNH”);
- General Service (“GSG”) customers; and
- Large Volume Service (“LVG”) customers.

The GEM excludes all other customers, including Firm Transportation Gas Service (“TSG-F”), Non-Firm Transportation Gas Service (“TSG-NF”), Contract Service (“CSG”), Cogeneration Interruptible Service (“CIG”), and Street Lighting Service (“SLG”).

Q. How did you determine which classes to include in the GEM?

A**.** Within electric service, the Residential, Residential TOU, GLPMDED, and LPL-S customers were chosen as the GEM-eligible customers because they account for the vast majority of the distribution base rate revenue from volumetric and demand charges. Table 1 summarizes the share of electric base revenue from each of the three rate types, by customer class, based on weather-normalized billing determinants filed in the rate case. Column 1 contains the share of revenue from volumetric rates; column 2 from demand charges; and column 3 from fixed service charges. For example, the first row of column 1 shows that 90 percent of RS base rate revenue comes from volumetric rates. Column 4 shows the share of PSE&G’s electric base revenue by customer class (*e.g.*, RS customers account for 44 percent of PSE&G's base rate revenue). Column 5 shows the share of PSE&G electric base rate revenue from volumetric rates or demand charges by customer class. It is calculated as the sum of columns 1 and 2 multiplied by column 4 (*e.g.*, for RS customers, (90% + 0%) x 44% = 40%). The total in the bottom right-hand corner of the table shows that 83 percent of PSE&G electric base rate revenue comes from volumetric rates or demand charges. The highlighted cells show that the GEM-eligible customer classes account for 78 of that 83 percent (where 78% = 40% + 0% + 0% + 21% + 16%). The important point to note is that, through the proposed GEM, PSE&G can remove 94 percent of its current link between customer usage and revenue (where 94% = 78% / 83%), thereby removing the Company's disincentive to promote energy efficiency to the customers that most impact distribution revenues.

Additionally, the included customer classes have a large enough number of customers such that the deferral associated with any one customer's usage change is *de minimis* when spread across the entire class for recovery or refund. The Residential class (RS and RHS) has approximately 1.9 million customers, the Residential TOU class has approximately 12,000 customers, GLPMDED has approximately 265,000 customers, and LPL-S has approximately 9,000 customers.

Table 1: Share of Electric Base Rate Revenue from Variable Charges

Customer Class	Share of Base Rate Revenue by Charge (1) Volumetric Rate	(2) Demand Charge	(3) Fixed Service Charge	(4) Share of PSE&G Base Rate Revenue	(5) % of Base Revenue from Volumetric or Demand Rates
Residential (RS)	90%	0%	10%	44%	40%
Residential Load Management (RLM)	73%	0%	27%	1%	0%
Residential Heating (RHS)	93%	0%	7%	0%	0%
Water Heating (WH)	100%	0%	0%	0%	0%
Water Heating Storage (WHS)	2%	0%	98%	0%	0%
Building Heating (HS)	94%	0%	6%	0%	0%
General Lighting and Power Measured Demand (GLPMDED)	18%	78%	5%	22%	21%
General Lighting and Power Night Use (GLPNU)	13%	52%	34%	0%	0%
General Lighting and Power Traffic Signal (GLPTS)	25%	60%	16%	0%	0%
Large Power and Lighting – Secondary (LPL-S)	0%	84%	16%	20%	16%
Large Power and Lighting – Primary (LPL-P)	0%	92%	8%	3%	3%
High Tension Service – Sub-transmission (HTSST)	0%	85%	15%	2%	2%
High Tension Service – High Voltage (HTSHV)	0%	86%	14%	0%	0%
Street Lighting	0%	0%	100%	7%	0%
Total	**44%**	**39%**	**17%**	**100%**	**83%**
Total in GEM				**86%**	**78%**

Q. Does a similar argument hold for the gas service classes included in the GEM?

A**.** Yes. In the case of gas service, the Residential, GSG, and LVG customers were chosen as the GEM-eligible customers because they account for the vast majority of the base rate revenue from volumetric (*i.e.,* per-therm) rates and demand rates. Table 2 provides the same information as Table 1, but for gas service instead of electric service. Also, it excludes customers whose revenue collected is treated as a pass-through to suppliers or non-base rate charges (customers in TSG-F, TSG-NF, CSG, and CIG). The total in the bottom right-hand corner of the table shows that 81 percent of PSE&G gas base rate revenue comes from volumetric or demand rates. The highlighted cells show the GEM-eligible customer classes. Through the proposed GEM, PSE&G can remove its current link between customer usage and revenue for the included gas customer classes.

Additionally, as with electric service, these classes have a large enough number of customers such that the deferral associated with any one customer's usage change is *de minimis* when spread across the entire class for recovery or refund. The Residential class has approximately 1.6 million customers, GSG has approximately 140,000 customers, and LVG has approximately 18,000 customers.

Table 2: Share of Gas Base Rate Revenue from Variable Charges

Customer Class	**Share of Base Rate Revenue by Charge**			**(4) Share of PSE&G Base Rate Revenue**	**(5) % of Base Revenue from Volumetric or Demand Rates**
	(1) Volumetric Rate	**(2) Demand Rate**	**(3) Fixed Service Charge**		
Residential (RSGH, RSGNH)	81%	0%	19%	73%	59%
General Service (GSG)	78%	0%	22%	12%	9%
Large Volume Service (LVG)	24%	58%	18%	15%	13%
Street Lighting	0%	0%	100%	0%	0%
Total	**72%**	**9%**	**19%**	**100%**	**81%**

Q. Why are some customer classes excluded from the GEM?

A. Street lighting classes are excluded because all revenues are obtained from fixed charges, so there is no link between sales and revenue to remove. The remaining excluded customer classes (*e.g.*, GLPNU, GLPTS, LPL Primary, HTS, and water heating services within electric service; and TSG-F, TSG-NF, CSG, and CIG within gas service) contain too few customers and contribute relatively little to PSE&G's disincentive to promote conservation and energy efficiency.

Q. Why did you put Residential TOU customers in their own GEM class rather than combining them with the RS and RHS customers?

A. The Residential TOU customers (served on RLM) receive their own GEM deferral because their rate design is significantly different from those of RS and RHS. Specifically, the monthly service charge is higher (currently $13.07 versus the $2.27 monthly service charge in RS and RHS) and the energy charges are comparatively low in all but the summer On-Peak pricing period. These rate differences create the possibility of cross subsidies if the RLM customers were pooled with the RS and RHS customers for purposes of the GEM.

Q. Does PSE&G propose to place limits on the GEM charge or credit?

A. PSE&G does not propose any limits on GEM credits. In contrast, PSE&G proposes to limit GEM charges in two ways. First, the GEM charge is capped at 6.5 percent of allowed distribution revenue, as calculated in the GEM. Deferrals in excess of 6.5 percent of allowed distribution revenue will remain in the deferral account for recovery in a future year. Note that 6.5 percent of *distribution revenue* is equivalent to a lower percentage of the customer's *total bill*, which includes supply charges, taxes, and other charges (*e.g.*, the Societal Benefits

Charge). The equivalent percentage based on the total bill depends on the levels of supply charges and other rates, which can vary over time, and are outside the purview of the GEM. At current rates as of November 1, 2017, the 6.5 percent cap in distribution revenue is equivalent to approximately 1.4 percent of the total bill for electric service and 2.5 percent of the bill for gas service. The 6.5 percent cap will be assessed on a class-by-class basis (*i.e.*, separately for Residential, Residential TOU, GLPMDED, and LPL-S electric service customers and Residential, GSG, and LVG gas service customers). The second limit on GEM charges is accomplished through an earnings test, which will match the test set forth in the Board's recently adopted Infrastructure Investment and Recovery mechanism. Deferrals in excess of the amount allowed by the earnings test will remain in the deferral account for recovery in a future year.

IV. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. Please summarize your testimony.

A. I have described PSE&G's proposed Green Enabling Mechanism (GEM), which would remove PSE&G's disincentive to promote conservation and energy efficiency to its electric (Residential, Residential TOU, GLPMDED, and LPL-S) and gas (Residential, GSG, and LVG) customers. The GEM accomplishes this task through a tracking account that removes the link between customer usage decisions and Company distribution revenue, with the resulting deferrals being collected from (or refunded to) customers through a dollar-per-kWh or dollar-per-therm charge (or credit) in the following year. The GEM is an important part of PSE&G's larger efforts to expand its energy efficiency programs. It aligns Company and ratepayer interests, ensuring PSE&G's presence as a partner in promoting conservation and energy efficiency with its customers. In addition, it maintains the Company's incentive to promote economic growth and operate efficiently.

Q. Please summarize your recommendations.

A. I recommend that the New Jersey Board of Public Utilities approves the GEM as described in my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

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Daniel G. Hansen

RESUME

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Academic Background:

PhD, Michigan State University, 1997, Economics
MA, Michigan State University, 1993, Economics
BA, Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Assisted a utility in forecasting the load impacts from a new residential peak-time rebate program.

Evaluated residential demand response pilot programs with programmable-controllable thermostats.

Developed long-term forecasting models for an electric utility.

Conducted a review of an electric utility's load forecasting methods.

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2017.

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark and Nick Crowley, 2017.

"2016 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2017.

"2016 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates," with Steven D. Braithwait and Michael Ty Clark, 2017.

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2016.

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2016.

"2015 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark, 2016.

"2015 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2016.

"Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report," with Steven Braithwait and David Armstrong, 2015.

“2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: *Ex-post* and *Ex-ante* Load Impacts,” with Steven Braithwait and David Armstrong, 2015.

“2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report,” with Steven Braithwait and David Armstrong, 2015.

“2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report,” with Tim Huegerich, 2015.

“2014 Load Impact Evaluation of Southern California Edison’s Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: *Ex-post* and *Ex-ante* Report,” with Marlies Patton, 2015.

“2014 Load Impact Evaluation of Pacific Gas and Electric Company’s Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: *Ex-post* and *Ex-ante* Report,” with Marlies Patton, 2015.

“FirstEnergy’s Smart Grid Investment Grant Consumer Behavior Study,” with EPRI (B. Neenan) and Marlies Patton, 2015.

“An Evaluation of Portland General Electric’s Decoupling Adjustment, Schedule 123,” with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

“Meeting Commonwealth Edison’s Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467,” with Michael O’Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

“A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation,” June 2007.

“Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007,” May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Arizona Public Service Company, Arizona Docket No. E–01345A–16–0036: Testimony supporting residential demand charges and a revenue decoupling mechanism on behalf of the Arizona Investment Council, 2017.

Black Hills/Colorado Electric Utility Company, Colorado Docket No. 16A-0436E: Testimony supporting energy and demand forecasting models on behalf of Black Hills/Colorado Electric Utility Company, 2016.

UNS Electric, Inc., Arizona Docket No. E–04204A-15-0142: Testimony supporting a residential demand charge proposed by UNS Electric on behalf of the Arizona Investment Council, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 15-00261-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 14-00332-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2014.

Xcel Energy, Inc., Minnesota E002/GR-13-868: Testimony supporting a revenue decoupling mechanism on behalf of Xcel Energy, 2013.

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an “Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources”, on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: “Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007,” May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: “Evaluation of the Klamath Project Alternatives Analysis Model,” March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

EXHIBIT P-10
Schedule DGH-2E
GEM Revenue per Customer Calculation Example
Based on current rates and test-year billing determinants

ELECTRIC

	(A)	(B)	(C)	(D)	(E)	(F)
				= (B x 1000) / C	= (A x 1000) / D	= Month's Value / Total
Month	Base Distribution Revenue ($000s)	Base Service Charge Revenue ($000s)	Base Service Charge Rate ($)	Base # of Customers	Base Revenue per Customer ($)	Base Monthly % of Annual
RS, RHS						
Jan-18	41,249	4,221	2.27	1,859,621	22	8%
Feb-18	35,466	4,208	2.27	1,853,618	19	7%
Mar-18	34,820	4,237	2.27	1,866,537	19	7%
Apr-18	29,328	4,223	2.27	1,860,513	16	6%
May-18	35,131	4,223	2.27	1,860,324	19	7%
Jun-18	58,562	4,258	2.27	1,875,840	31	11%
Jul-17	71,048	4,259	2.27	1,876,061	38	14%
Aug-17	66,826	4,235	2.27	1,865,502	36	13%
Sep-17	42,344	4,251	2.27	1,872,503	23	8%
Oct-17	29,990	4,252	2.27	1,873,168	16	6%
Nov-17	32,387	4,251	2.27	1,872,865	17	6%
Dec-17	40,727	4,240	2.27	1,867,805	22	8%
Total, Average	517,878	50,858	*2.27*	*1,867,030*	277	100%
RLM						
Jan-18	431	153	13.07	11,733	37	6%
Feb-18	381	153	13.07	11,687	33	6%
Mar-18	391	155	13.07	11,863	33	6%
Apr-18	330	152	13.07	11,593	28	5%
May-18	498	152	13.07	11,622	43	7%
Jun-18	980	154	13.07	11,762	83	14%
Jul-17	1,162	162	13.07	12,397	94	16%
Aug-17	1,163	158	13.07	12,114	96	16%
Sep-17	557	160	13.07	12,213	46	8%
Oct-17	333	151	13.07	11,549	29	5%
Nov-17	342	160	13.07	12,247	28	5%
Dec-17	425	152	13.07	11,650	36	6%
Total, Average	6,994	1,862	*13.07*	*11,869*	586	100%
GLPMDED						
Jan-18	12,450	1,080	3.96	272,611	46	5%
Feb-18	12,074	1,069	3.96	269,848	45	5%
Mar-18	13,022	1,086	3.96	274,328	47	5%
Apr-18	12,568	1,078	3.96	272,221	46	5%
May-18	22,400	1,074	3.96	271,319	83	8%
Jun-18	39,970	1,081	3.96	272,985	146	15%
Jul-17	39,541	1,021	3.96	257,795	153	16%
Aug-17	41,552	999	3.96	252,289	165	17%
Sep-17	26,993	1,022	3.96	258,157	105	11%
Oct-17	12,455	957	3.96	241,625	52	5%
Nov-17	12,439	998	3.96	252,009	49	5%
Dec-17	13,285	1,069	3.96	270,065	49	5%
Total, Average	258,748	12,534		*263,771*	986	100%
LPLS						
Jan-18	11,040	3,152	347.77	9,064	1,218	5%
Feb-18	10,803	3,163	347.77	9,094	1,188	5%
Mar-18	11,267	3,166	347.77	9,102	1,238	5%
Apr-18	11,245	3,179	347.77	9,140	1,230	5%
May-18	19,630	3,147	347.77	9,048	2,170	8%
Jun-18	31,550	3,141	347.77	9,031	3,493	14%
Jul-17	35,341	3,080	347.77	8,856	3,991	15%
Aug-17	36,476	3,089	347.77	8,883	4,106	16%
Sep-17	22,778	3,035	347.77	8,727	2,610	10%
Oct-17	16,353	2,911	347.77	8,370	1,954	8%
Nov-17	11,212	2,831	347.77	8,140	1,377	5%
Dec-17	10,721	3,033	347.77	8,721	1,229	5%
Total, Average	228,415	36,925	*347.77*	*8,848*	25,804	100%

EXHIBIT P-10
Schedule DGH-2G
GEM Revenue per Customer Calculation Example
Based on current rates and test-year billing determinants

GAS

	(A)	(B)	(C)	(D)	(E)	(F)
				= (B x 1000) / C	= (A x 1000) / D	= Month's Value / Total
Month	Base Distribution Revenue ($000s)	Base Service Charge Revenue ($000s)	Base Service Charge Rate ($)	Base # of Customers	Base Revenue per Customer ($)	Base Monthly % of Annual
RSG						
May-18	27,371	8,838	5.46	1,618,709	17	5%
Jun-18	21,678	8,901	5.46	1,630,164	13	4%
Jul-17	18,366	9,354	5.46	1,713,242	11	3%
Aug-17	17,748	8,685	5.46	1,590,692	11	3%
Sep-17	18,780	8,927	5.46	1,634,904	11	3%
Oct-17	28,371	8,852	5.46	1,621,191	18	5%
Nov-17	52,969	8,924	5.46	1,634,354	32	9%
Dec-17	84,287	8,840	5.46	1,619,032	52	15%
Jan-18	100,490	8,827	5.46	1,616,717	62	18%
Feb-18	88,455	8,818	5.46	1,615,003	55	15%
Mar-18	74,821	8,858	5.46	1,622,310	46	13%
Apr-18	42,796	8,849	5.46	1,620,664	26	7%
Total, Average	576,133	106,672	*5.46*	*1,628,082*	355	100%
GSG						
May-18	4,501	1,717	12.22	140,495	32	5%
Jun-18	4,019	1,728	12.22	141,420	28	4%
Jul-17	3,793	1,706	11.59	147,194	26	4%
Aug-17	3,386	1,587	11.59	136,895	25	4%
Sep-17	3,501	1,624	11.64	139,506	25	4%
Oct-17	5,588	1,630	11.64	140,009	40	6%
Nov-17	7,775	1,631	11.64	140,153	55	8%
Dec-17	12,676	1,629	11.64	139,986	91	14%
Jan-18	15,156	1,713	12.22	140,147	108	16%
Feb-18	14,184	1,700	12.22	139,104	102	15%
Mar-18	12,279	1,723	12.22	140,973	87	13%
Apr-18	6,546	1,715	12.22	140,363	47	7%
Total, Average	93,404	20,102	*11.92*	*140,520*	666	100%
LVG						
May-18	3,084	1,878	100.12	18,756	164	2%
Jun-18	3,208	1,850	100.12	18,482	174	3%
Jul-17	2,880	1,868	100.12	18,662	154	2%
Aug-17	2,825	1,785	100.12	17,829	158	2%
Sep-17	2,758	1,762	100.12	17,603	157	2%
Oct-17	9,906	1,820	100.12	18,181	545	8%
Nov-17	17,944	1,789	100.12	17,866	1,004	15%
Dec-17	18,643	1,799	100.12	17,968	1,038	16%
Jan-18	21,055	1,864	100.12	18,621	1,131	17%
Feb-18	20,898	1,861	100.12	18,589	1,124	17%
Mar-18	15,179	1,883	100.12	18,808	807	12%
Apr-18	4,159	1,881	100.12	18,783	221	3%
Total, Average	122,537	22,041	*100.12*	*18,346*	6,678	100%

EXHIBIT P-10
Schedule DGH-3E
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

ELECTRIC

Month	(A) DGH-2E Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2E Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
RS, RHS						
Jan-19	8%		0	0	1,859,621	0.0
Feb-19	7%		0	0	1,853,618	0.0
Mar-19	7%	3,000	3,000	202	1,866,537	0.1
Apr-19	6%		3,000	171	1,860,513	0.1
May-19	7%		3,000	204	1,860,324	0.1
Jun-19	11%		3,000	338	1,875,840	0.2
Jul-19	14%		3,000	410	1,876,061	0.2
Aug-19	13%		3,000	388	1,865,502	0.2
Sep-19	8%	3,000	6,000	489	1,872,503	0.3
Oct-19	6%		6,000	346	1,873,168	0.2
Nov-19	6%		6,000	374	1,872,865	0.2
Dec-19	8%		6,000	472	1,867,805	0.3
Jan-20	8%		6,000	480	1,859,621	0.3
Feb-20	7%		6,000	414	1,853,618	0.2
Mar-20	7%	3,000	9,000	606	1,866,537	0.3
Apr-20	6%		9,000	512	1,860,513	0.3
May-20	7%		9,000	613	1,860,324	0.3
Jun-20	11%		9,000	1,013	1,875,840	0.5
Jul-20	14%		9,000	1,229	1,876,061	0.7
Aug-20	13%		9,000	1,163	1,865,502	0.6
Sep-20	8%	3,000	12,000	979	1,872,503	0.5
Oct-20	6%		12,000	693	1,873,168	0.4
Nov-20	6%		12,000	748	1,872,865	0.4
Dec-20	8%		12,000	944	1,867,805	0.5

EXHIBIT P-10
Schedule DGH-3E
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

ELECTRIC

Month	(A) DGH-2E Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2E Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
RLM						
Jan-19	6%		0	0	11,733	0.0
Feb-19	6%		0	0	11,687	0.0
Mar-19	6%	40	40	2	11,863	0.2
Apr-19	5%		40	2	11,593	0.2
May-19	7%		40	3	11,622	0.3
Jun-19	14%		40	6	11,762	0.5
Jul-19	16%		40	6	12,397	0.5
Aug-19	16%		40	7	12,114	0.5
Sep-19	8%	40	80	6	12,213	0.5
Oct-19	5%		80	4	11,549	0.3
Nov-19	5%		80	4	12,247	0.3
Dec-19	6%		80	5	11,650	0.4
Jan-20	6%		80	5	11,733	0.4
Feb-20	6%		80	4	11,687	0.4
Mar-20	6%	40	120	7	11,863	0.6
Apr-20	5%		120	6	11,593	0.5
May-20	7%		120	9	11,622	0.8
Jun-20	14%		120	17	11,762	1.5
Jul-20	16%		120	19	12,397	1.5
Aug-20	16%		120	20	12,114	1.6
Sep-20	8%	40	160	12	12,213	1.0
Oct-20	5%		160	8	11,549	0.7
Nov-20	5%		160	8	12,247	0.6
Dec-20	6%		160	10	11,650	0.9

EXHIBIT P-10
Schedule DGH-3E
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

ELECTRIC

Month	(A) DGH-2E Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2E Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
GLPMDED						
Jan-19	5%		0	0	272,611	0.0
Feb-19	5%		0	0	269,848	0.0
Mar-19	5%	1,500	1,500	72	274,328	0.3
Apr-19	5%		1,500	70	272,221	0.3
May-19	8%		1,500	126	271,319	0.5
Jun-19	15%		1,500	223	272,985	0.8
Jul-19	16%		1,500	233	257,795	0.9
Aug-19	17%		1,500	251	252,289	1.0
Sep-19	11%	1,500	3,000	318	258,157	1.2
Oct-19	5%		3,000	157	241,625	0.6
Nov-19	5%		3,000	150	252,009	0.6
Dec-19	5%		3,000	150	270,065	0.6
Jan-20	5%		3,000	139	272,611	0.5
Feb-20	5%		3,000	136	269,848	0.5
Mar-20	5%	1,500	4,500	217	274,328	0.8
Apr-20	5%		4,500	211	272,221	0.8
May-20	8%		4,500	377	271,319	1.4
Jun-20	15%		4,500	668	272,985	2.4
Jul-20	16%		4,500	700	257,795	2.7
Aug-20	17%		4,500	752	252,289	3.0
Sep-20	11%	1,500	6,000	636	258,157	2.5
Oct-20	5%		6,000	314	241,625	1.3
Nov-20	5%		6,000	300	252,009	1.2
Dec-20	5%		6,000	299	270,065	1.1

EXHIBIT P-10
Schedule DGH-3E
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

ELECTRIC

Month	(A) DGH-2E Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2E Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
LPLS						
Jan-19	5%		0	0	9,064	0.0
Feb-19	5%		0	0	9,094	0.0
Mar-19	5%	1,500	1,500	72	9,102	7.9
Apr-19	5%		1,500	72	9,140	7.8
May-19	8%		1,500	126	9,048	13.9
Jun-19	14%		1,500	203	9,031	22.5
Jul-19	15%		1,500	232	8,856	26.2
Aug-19	16%		1,500	239	8,883	26.9
Sep-19	10%	1,500	3,000	303	8,727	34.8
Oct-19	8%		3,000	227	8,370	27.1
Nov-19	5%		3,000	160	8,140	19.7
Dec-19	5%		3,000	143	8,721	16.4
Jan-20	5%		3,000	142	9,064	15.6
Feb-20	5%		3,000	138	9,094	15.2
Mar-20	5%	1,500	4,500	216	9,102	23.7
Apr-20	5%		4,500	215	9,140	23.5
May-20	8%		4,500	378	9,048	41.8
Jun-20	14%		4,500	609	9,031	67.5
Jul-20	15%		4,500	696	8,856	78.6
Aug-20	16%		4,500	716	8,883	80.6
Sep-20	10%	1,500	6,000	607	8,727	69.5
Oct-20	8%		6,000	454	8,370	54.3
Nov-20	5%		6,000	320	8,140	39.3
Dec-20	5%		6,000	286	8,721	32.8

EXHIBIT P-10
Schedule DGH-3G
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

GAS

Month	(A) DGH-2G Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2G Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
RSG						
May-19	5%		0	0	1,618,709	0.0
Jun-19	4%		0	0	1,630,164	0.0
Jul-19	3%	3,000	3,000	91	1,713,242	0.1
Aug-19	3%		3,000	94	1,590,692	0.1
Sep-19	3%		3,000	97	1,634,904	0.1
Oct-19	5%		3,000	148	1,621,191	0.1
Nov-19	9%		3,000	274	1,634,354	0.2
Dec-19	15%		3,000	440	1,619,032	0.3
Jan-20	18%	3,000	6,000	1,051	1,616,717	0.6
Feb-20	15%		6,000	926	1,615,003	0.6
Mar-20	13%		6,000	780	1,622,310	0.5
Apr-20	7%		6,000	446	1,620,664	0.3
May-20	5%		6,000	286	1,618,709	0.2
Jun-20	4%		6,000	225	1,630,164	0.1
Jul-20	3%	3,000	9,000	272	1,713,242	0.2
Aug-20	3%		9,000	283	1,590,692	0.2
Sep-20	3%		9,000	291	1,634,904	0.2
Oct-20	5%		9,000	444	1,621,191	0.3
Nov-20	9%		9,000	822	1,634,354	0.5
Dec-20	15%		9,000	1,320	1,619,032	0.8
Jan-21	18%	3,000	12,000	2,101	1,616,717	1.3
Feb-21	15%		12,000	1,851	1,615,003	1.1
Mar-21	13%		12,000	1,559	1,622,310	1.0
Apr-21	7%		12,000	893	1,620,664	0.6

EXHIBIT P-10
Schedule DGH-3G
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

GAS

Month	(A) DGH-2G Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2G Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
<u>GSG</u>						
May-19	5%		0	0	140,495	0.0
Jun-19	4%		0	0	141,420	0.0
Jul-19	4%	500	500	19	147,194	0.1
Aug-19	4%		500	19	136,895	0.1
Sep-19	4%		500	19	139,506	0.1
Oct-19	6%		500	30	140,009	0.2
Nov-19	8%		500	42	140,153	0.3
Dec-19	14%		500	68	139,986	0.5
Jan-20	16%	500	1,000	162	140,147	1.2
Feb-20	15%		1,000	153	139,104	1.1
Mar-20	13%		1,000	131	140,973	0.9
Apr-20	7%		1,000	70	140,363	0.5
May-20	5%		1,000	48	140,495	0.3
Jun-20	4%		1,000	43	141,420	0.3
Jul-20	4%	500	1,500	58	147,194	0.4
Aug-20	4%		1,500	56	136,895	0.4
Sep-20	4%		1,500	57	139,506	0.4
Oct-20	6%		1,500	90	140,009	0.6
Nov-20	8%		1,500	125	140,153	0.9
Dec-20	14%		1,500	204	139,986	1.5
Jan-21	16%	500	2,000	325	140,147	2.3
Feb-21	15%		2,000	306	139,104	2.2
Mar-21	13%		2,000	262	140,973	1.9
Apr-21	7%		2,000	140	140,363	1.0

EXHIBIT P-10
Schedule DGH-3G
Revenue per Customer Update Example
Simple example of impact of semi-annual annual revenue requirement roll-ins

GAS

Month	(A) DGH-2G Base Monthly % of Annual	(B) Annual Revenue Requirement ($000s)	(C) Cumulative Revenue Requirement ($000s)	(D) = A x C Monthly Revenue Requirement ($000s)	(E) DGH-2G Base # of Customers	(F) = (D x 1000) / E Revenue per Customer Adjustment ($)
LVG						
May-19	2%		0	0	18,756	0.0
Jun-19	3%		0	0	18,482	0.0
Jul-19	2%	500	500	12	18,662	0.6
Aug-19	2%		500	12	17,829	0.7
Sep-19	2%		500	12	17,603	0.7
Oct-19	8%		500	41	18,181	2.2
Nov-19	15%		500	75	17,866	4.2
Dec-19	16%		500	78	17,968	4.3
Jan-20	17%	500	1,000	169	18,621	9.1
Feb-20	17%		1,000	168	18,589	9.1
Mar-20	12%		1,000	121	18,808	6.4
Apr-20	3%		1,000	33	18,783	1.8
May-20	2%		1,000	25	18,756	1.3
Jun-20	3%		1,000	26	18,482	1.4
Jul-20	2%	500	1,500	35	18,662	1.9
Aug-20	2%		1,500	36	17,829	2.0
Sep-20	2%		1,500	35	17,603	2.0
Oct-20	8%		1,500	122	18,181	6.7
Nov-20	15%		1,500	226	17,866	12.6
Dec-20	16%		1,500	233	17,968	13.0
Jan-21	17%	500	2,000	339	18,621	18.2
Feb-21	17%		2,000	337	18,589	18.1
Mar-21	12%		2,000	242	18,808	12.9
Apr-21	3%		2,000	66	18,783	3.5

EXHIBIT P-10
Schedule DGH-4E
Green Enabling Mechanism Deferral Example
Assumes a 0.5% increase in the number of customers served and 1.0% increase in revenue compared to base

ELECTRIC

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			= (A x 1000) / B	DGH-2E	DGH-3E	= D + E	= F x C / 1000		= G - H	DGH-6E	= I + J
Month	Actual Service Charge Revenue ($000s)	Actual Service Charge Rate ($)	# of Customers	Base Revenue per Customer ($)	Revenue per Customer Adjustment ($)	Allowed Revenue per Customer ($)	Allowed Revenue ($000s)	Actual Revenue ($000s)	Deferral to Collect/ (Credit) excl Interest ($000s)	Interest to Collect / (Credit) ($000s)	Deferral to Collect/ (Credit) incl Interest ($000s)
RS, RHS											
Jan-19	4,242	2.27	1,868,919	22	0	22	41,455	41,661	(206)		
Feb-19	4,229	2.27	1,862,886	19	0	19	35,643	35,820	(177)		
Mar-19	4,258	2.27	1,875,870	19	0	19	35,197	35,168	29		
Apr-19	4,244	2.27	1,869,816	16	0	16	29,646	29,621	25		
May-19	4,244	2.27	1,869,626	19	0	19	35,512	35,482	30		
Jun-19	4,279	2.27	1,885,220	31	0	31	59,194	59,147	47		
Jul-19	4,280	2.27	1,885,442	38	0	38	71,815	71,759	57		
Aug-19	4,256	2.27	1,874,830	36	0	36	67,550	67,494	55		
Sep-19	4,272	2.27	1,881,865	23	0	23	43,047	42,767	280		
Oct-19	4,273	2.27	1,882,534	16	0	16	30,489	30,290	198		
Nov-19	4,273	2.27	1,882,230	17	0	17	32,925	32,711	214		
Dec-19	4,261	2.27	1,877,144	22	0	22	41,405	41,135	271		
Total, Average	51,112		*1,876,365*	277	2	279	523,878	523,057	822	(1)	820
RLM											
Jan-19	154	13.07	11,792	37	0	37	433	436	(2)		
Feb-19	154	13.07	11,745	33	0	33	383	384	(2)		
Mar-19	156	13.07	11,922	33	0	33	396	395	0		
Apr-19	152	13.07	11,651	28	0	29	334	333	0		
May-19	153	13.07	11,680	43	0	43	504	503	0		
Jun-19	155	13.07	11,821	83	0	84	990	990	1		
Jul-19	163	13.07	12,459	94	1	94	1,174	1,173	1		
Aug-19	159	13.07	12,175	96	1	97	1,175	1,174	1		
Sep-19	160	13.07	12,274	46	1	46	567	563	3		
Oct-19	152	13.07	11,607	29	0	29	339	337	2		
Nov-19	161	13.07	12,308	28	0	28	348	346	2		
Dec-19	153	13.07	11,708	36	0	37	432	429	3		
Total, Average	1,871		*11,929*	586	4	589	7,074	7,064	10	(0)	10
GLPMDED											
Jan-19	1,085	3.96	273,974	46	0	46	12,512	12,574	(62)		
Feb-19	1,074	3.96	271,197	45	0	45	12,134	12,195	(60)		
Mar-19	1,092	3.96	275,700	47	0	48	13,159	13,152	7		
Apr-19	1,083	3.96	273,582	46	0	46	12,701	12,694	8		
May-19	1,080	3.96	272,675	83	0	83	22,638	22,624	14		
Jun-19	1,086	3.96	274,350	146	1	147	40,394	40,370	24		
Jul-19	1,026	3.96	259,084	153	1	154	39,973	39,937	37		
Aug-19	1,004	3.96	253,551	165	1	166	42,012	41,968	44		
Sep-19	1,027	3.96	259,448	105	1	106	27,448	27,263	185		
Oct-19	962	3.96	242,834	52	1	52	12,675	12,580	95		
Nov-19	1,003	3.96	253,269	49	1	50	12,652	12,563	89		
Dec-19	1,075	3.96	271,415	49	1	50	13,502	13,418	84		
Total, Average	12,597		*265,090*	986	7	992	261,800	261,335	465	1	466
LPLS											
Jan-19	3,168	347.77	9,109	1,218	0	1,218	11,095	11,150	(55)		
Feb-19	3,178	347.77	9,140	1,188	0	1,188	10,857	10,911	(54)		
Mar-19	3,181	347.77	9,148	1,238	8	1,246	11,396	11,380	16		
Apr-19	3,195	347.77	9,186	1,230	8	1,238	11,373	11,357	16		
May-19	3,162	347.77	9,093	2,170	14	2,183	19,855	19,827	29		
Jun-19	3,156	347.77	9,076	3,493	22	3,516	31,912	31,866	46		
Jul-19	3,095	347.77	8,900	3,991	26	4,017	35,751	35,694	56		
Aug-19	3,105	347.77	8,927	4,106	27	4,133	36,898	36,840	58		
Sep-19	3,050	347.77	8,771	2,610	35	2,645	23,197	23,006	191		
Oct-19	2,925	347.77	8,412	1,954	27	1,981	16,663	16,516	147		
Nov-19	2,845	347.77	8,181	1,377	20	1,397	11,429	11,324	105		
Dec-19	3,048	347.77	8,765	1,229	16	1,246	10,919	10,828	90		
Total, Average	37,110	*347.77*	*8,892*	25,804	203	26,007	231,343	230,699	644	3	646

EXHIBIT P-10
Schedule DGH-4G
Green Enabling Mechanism Deferral Example
Assumes a 0.5% increase in the number of customers served and 1.0% increase in revenue compared to base

GAS

	(A)	(B)	(C) = (A x 1000) / B	(D) DGH-2G	(E) DGH-3G	(F) = D + E	(G) = F x C / 1000	(H)	(I) = G - H	(J) DGH-6G	(K) = I + J
Month	Actual Service Charge Revenue ($000s)	Actual Service Charge Rate ($)	# of Customers	Base Revenue per Customer ($)	Revenue per Customer Adjustment ($)	Allowed Revenue per Customer ($)	Allowed Revenue ($000s)	Actual Revenue ($000s)	Deferral to Collect/ (Credit) excl Interest ($000s)	Interest to Collect / (Credit) ($000s)	Deferral to Collect/ (Credit) incl Interest ($000s)
RSG											
May-19	8,882	5.46	1,626,803	17	0	17	27,508	27,645	(137)		
Jun-19	8,945	5.46	1,638,315	13	0	13	21,786	21,895	(108)		
Jul-19	9,401	5.46	1,721,808	11	0	11	18,549	18,549	(1)		
Aug-19	8,729	5.46	1,598,645	11	0	11	17,932	17,926	6		
Sep-19	8,971	5.46	1,643,078	11	0	12	18,972	18,968	4		
Oct-19	8,896	5.46	1,629,297	18	0	18	28,662	28,655	7		
Nov-19	8,968	5.46	1,642,526	32	0	33	53,509	53,499	10		
Dec-19	8,884	5.46	1,627,127	52	0	52	85,150	85,129	21		
Jan-20	8,871	5.46	1,624,801	62	1	63	102,049	101,495	553		
Feb-20	8,862	5.46	1,623,078	55	1	55	89,827	89,339	488		
Mar-20	8,902	5.46	1,630,422	46	0	47	75,979	75,569	409		
Apr-20	8,893	5.46	1,628,768	26	0	27	43,458	43,224	235		
Total, Average	107,205	*5.46*	*1,636,222*	355	3	358	583,381	581,894	1,487	3	1,489
GSG											
May-19	1,725	12.22	141,198	32	0	32	4,524	4,546	(23)		
Jun-19	1,737	12.22	142,127	28	0	28	4,039	4,059	(20)		
Jul-19	1,715	11.59	147,930	26	0	26	3,831	3,831	0		
Aug-19	1,595	11.59	137,580	25	0	25	3,422	3,420	2		
Sep-19	1,632	11.64	140,204	25	0	25	3,538	3,536	1		
Oct-19	1,638	11.64	140,709	40	0	40	5,646	5,644	2		
Nov-19	1,640	11.64	140,854	55	0	56	7,855	7,852	3		
Dec-19	1,638	11.64	140,686	91	0	91	12,808	12,803	5		
Jan-20	1,721	12.22	140,848	108	1	109	15,395	15,307	87		
Feb-20	1,708	12.22	139,799	102	1	103	14,409	14,326	83		
Mar-20	1,731	12.22	141,677	87	1	88	12,472	12,402	70		
Apr-20	1,724	12.22	141,065	47	0	47	6,649	6,611	38		
Total, Average	20,203	*11.92*	*141,223*	666	5	671	94,587	94,338	249	0	250
LVG											
May-19	1,887	100.12	18,850	164	0	164	3,099	3,114	(15)		
Jun-19	1,860	100.12	18,574	174	0	174	3,224	3,240	(16)		
Jul-19	1,878	100.12	18,756	154	1	155	2,906	2,909	(3)		
Aug-19	1,794	100.12	17,918	158	1	159	2,851	2,853	(2)		
Sep-19	1,771	100.12	17,691	157	1	157	2,783	2,785	(2)		
Oct-19	1,829	100.12	18,272	545	2	547	9,997	10,005	(9)		
Nov-19	1,798	100.12	17,956	1,004	4	1,009	18,109	18,123	(14)		
Dec-19	1,808	100.12	18,058	1,038	4	1,042	18,814	18,829	(15)		
Jan-20	1,874	100.12	18,714	1,131	9	1,140	21,331	21,266	65		
Feb-20	1,870	100.12	18,681	1,124	9	1,133	21,172	21,107	65		
Mar-20	1,892	100.12	18,902	807	6	813	15,376	15,331	46		
Apr-20	1,890	100.12	18,876	221	2	223	4,213	4,201	13		
Total, Average	22,151	*100.12*	*18,437*	6,678	39	6,717	123,874	123,762	111	(0)	111

EXHIBIT P-10
Schedule DGH-5E
Green Enabling Charge or Credit Example
Forecasted sales as calculated by PSE&G

ELECTRIC

		(A)	(B)	(C)
			DGH-4E	= (B x 1000) / A
Month		Forecasted Sales (kWh)	Deferral to be Collected/ (Credited) ($000s)	Rate per kWh
RS, RHS				
	Jun-20	1,322,250,144		
	Jul-20	1,703,943,081		
	Aug-20	1,585,490,050		
	Sep-20	1,122,310,470		
	Oct-20	867,767,489		
	Nov-20	851,034,142		
	Dec-20	1,072,975,530		
	Jan-21	1,114,017,868		
	Feb-21	945,624,293		
	Mar-21	938,871,130		
	Apr-21	752,152,879		
	May-21	865,944,503		
Total		13,142,381,577	820	0.000062
RLM				
	Jun-20	22,627,872		
	Jul-20	28,473,079		
	Aug-20	27,585,931		
	Sep-20	19,723,880		
	Oct-20	14,326,040		
	Nov-20	13,098,871		
	Dec-20	16,402,762		
	Jan-21	18,798,035		
	Feb-21	15,549,881		
	Mar-21	16,082,180		
	Apr-21	11,814,992		
	May-21	14,344,620		
Total		218,828,143	10	0.000046
GLPMDED				
	Jun-20	726,905,982		
	Jul-20	810,484,688		
	Aug-20	808,327,987		
	Sep-20	680,186,000		
	Oct-20	622,108,267		
	Nov-20	570,567,785		
	Dec-20	638,458,769		
	Jan-21	665,231,970		
	Feb-21	628,724,485		
	Mar-21	667,832,183		
	Apr-21	569,262,002		
	May-21	610,637,877		
Total		7,998,727,996	466	0.000058
LPLS				
	Jun-20	1,044,332,297		
	Jul-20	1,178,378,218		
	Aug-20	1,167,718,236		
	Sep-20	984,622,830		
	Oct-20	989,319,794		
	Nov-20	915,579,532		
	Dec-20	986,018,746		
	Jan-21	1,033,869,012		
	Feb-21	961,631,009		
	Mar-21	1,016,256,138		
	Apr-21	862,274,889		
	May-21	1,024,257,024		
Total		12,164,257,725	646	0.000053

EXHIBIT P-10
Schedule DGH-5G
Green Enabling Charge or Credit Example
Forecasted sales as calculated by PSE&G

GAS

Month	(A) Forecasted Sales (Therms)	(B) DGH-4G Deferral to be Collected/ (Credited) ($000s)	(C) = (B x 1000) / A Rate per Therm
RSG			
Oct-20	66,995,138		
Nov-20	160,951,200		
Dec-20	249,703,696		
Jan-21	273,086,988		
Feb-21	245,943,005		
Mar-21	204,044,552		
Apr-21	104,955,599		
May-21	57,894,663		
Jun-21	41,231,041		
Jul-21	30,001,804		
Aug-21	29,322,776		
Sep-21	30,425,557		
Total	1,494,556,020	1,489	0.000997
GSG			
Oct-20	12,390,112		
Nov-20	25,196,833		
Dec-20	43,397,648		
Jan-21	52,230,164		
Feb-21	49,701,717		
Mar-21	42,562,289		
Apr-21	18,991,622		
May-21	10,681,551		
Jun-21	8,818,423		
Jul-21	6,821,999		
Aug-21	6,397,360		
Sep-21	8,129,379		
Total	285,319,097	250	0.000876
LVG			
Oct-20	44,394,748		
Nov-20	63,026,491		
Dec-20	91,379,865		
Jan-21	110,620,667		
Feb-21	109,091,266		
Mar-21	98,192,844		
Apr-21	53,457,224		
May-21	28,007,836		
Jun-21	31,082,494		
Jul-21	21,250,992		
Aug-21	24,627,409		
Sep-21	22,680,364		
Total	697,812,201	111	0.000159

EXHIBIT P-10

Schedule DGH-6E

GEM Interest Calculation Example

Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

ELECTRIC

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5E (Sales*Rate)	DGH-4E	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
RS, RHS										
Jan-19	0	0	(206)	(206)	(206)	(103)	2.20%	(0)		(0)
Feb-19	(206)	0	(177)	(177)	(384)	(295)	2.20%	(1)		(1)
Mar-19	(384)	0	29	29	(355)	(369)	2.20%	(1)		(1)
Apr-19	(355)	0	25	25	(330)	(342)	2.20%	(1)		(2)
May-19	(330)	0	30	30	(300)	(315)	2.20%	(1)		(3)
Jun-19	(300)	0	47	47	(254)	(277)	2.20%	(1)		(3)
Jul-19	(254)	0	57	57	(197)	(225)	2.20%	(0)		(4)
Aug-19	(197)	0	55	55	(142)	(169)	2.20%	(0)		(4)
Sep-19	(142)	0	280	280	138	(2)	2.20%	(0)		(4)
Oct-19	138	0	198	198	337	238	2.20%	0		(3)
Nov-19	337	0	214	214	551	444	2.20%	1		(3)
Dec-19	551	0	271	271	822	686	2.20%	1		(1)
Jan-20	820	0	0	0	820	820	2.20%	2	(1)	2
Feb-20	820	0	0	0	820	820	2.20%	2		3
Mar-20	820	0	0	0	820	820	2.20%	2		5
Apr-20	820	0	0	0	820	820	2.20%	2		6
May-20	820	0	0	0	820	820	2.20%	2		8
Jun-20	820	83	0	(83)	738	779	2.20%	1		9
Jul-20	738	106	0	(106)	631	685	2.20%	1		10
Aug-20	631	99	0	(99)	532	582	2.20%	1		11
Sep-20	532	70	0	(70)	462	497	2.20%	1		12
Oct-20	462	54	0	(54)	408	435	2.20%	1		13
Nov-20	408	53	0	(53)	355	382	2.20%	1		14
Dec-20	355	67	0	(67)	288	322	2.20%	1		14
Jan-21	288	70	0	(70)	219	253	2.20%	0		15
Feb-21	219	59	0	(59)	160	189	2.20%	0		15
Mar-21	160	59	0	(59)	101	130	2.20%	0		15
Apr-21	101	47	0	(47)	54	78	2.20%	0		15
May-21	54	54	0	(54)	(0)	27	2.20%	0		16

EXHIBIT P-10
Schedule DGH-6E
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

ELECTRIC

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5E (Sales*Rate)	DGH-4E	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
RLM										
Jan-19	0	0	(2)	(2)	(2)	(1)	2.20%	(0)		(0)
Feb-19	(2)	0	(2)	(2)	(4)	(3)	2.20%	(0)		(0)
Mar-19	(4)	0	0	0	(4)	(4)	2.20%	(0)		(0)
Apr-19	(4)	0	0	0	(3)	(4)	2.20%	(0)		(0)
May-19	(3)	0	0	0	(3)	(3)	2.20%	(0)		(0)
Jun-19	(3)	0	1	1	(2)	(3)	2.20%	(0)		(0)
Jul-19	(2)	0	1	1	(2)	(2)	2.20%	(0)		(0)
Aug-19	(2)	0	1	1	(1)	(1)	2.20%	(0)		(0)
Sep-19	(1)	0	3	3	3	1	2.20%	0		(0)
Oct-19	3	0	2	2	5	4	2.20%	0		(0)
Nov-19	5	0	2	2	7	6	2.20%	0		(0)
Dec-19	7	0	3	3	10	9	2.20%	0		(0)
Jan-20	10	0	0	0	10	10	2.20%	0	(0)	0
Feb-20	10	0	0	0	10	10	2.20%	0		0
Mar-20	10	0	0	0	10	10	2.20%	0		0
Apr-20	10	0	0	0	10	10	2.20%	0		0
May-20	10	0	0	0	10	10	2.20%	0		0
Jun-20	10	1	0	(1)	9	9	2.20%	0		0
Jul-20	9	1	0	(1)	8	8	2.20%	0		0
Aug-20	8	1	0	(1)	6	7	2.20%	0		0
Sep-20	6	1	0	(1)	6	6	2.20%	0		0
Oct-20	6	1	0	(1)	5	5	2.20%	0		0
Nov-20	5	1	0	(1)	4	5	2.20%	0		0
Dec-20	4	1	0	(1)	4	4	2.20%	0		0
Jan-21	4	1	0	(1)	3	3	2.20%	0		0
Feb-21	3	1	0	(1)	2	2	2.20%	0		0
Mar-21	2	1	0	(1)	1	2	2.20%	0		0
Apr-21	1	1	0	(1)	1	1	2.20%	0		0
May-21	1	1	0	(1)	0	0	2.20%	0		0

EXHIBIT P-10
Schedule DGH-6E
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

ELECTRIC

Month	(A) Prior E - I Under / (Over) Recovery Beginning Balance ($000s)	(B) DGH-5E (Sales*Rate) Revenues Collected / (Credited) ($000s)	(C) DGH-4E Deferral to Collect / (Credit) excl interest ($000s)	(D) = C - B Under / (Over) Recovery ($000s)	(E) = A + D Under / (Over) Recovery Ending Balance ($000s)	(F) = (A + E) / 2 Under / (Over) Average Monthly Balance ($000s)	(G) Interest Rate Annualized	(H) = F * G Interest Income / (Expense) Average Monthly Balance ($000s)	(I) Interest Roll-In ($000s)	(J) = Prior J + H - I Cumulative Interest ($000s)
GLPMDED										
Jan-19	0	0	(62)	(62)	(62)	(31)	2.20%	(0)		(0)
Feb-19	(62)	0	(60)	(60)	(123)	(92)	2.20%	(0)		(0)
Mar-19	(123)	0	7	7	(115)	(119)	2.20%	(0)		(0)
Apr-19	(115)	0	8	8	(107)	(111)	2.20%	(0)		(1)
May-19	(107)	0	14	14	(93)	(100)	2.20%	(0)		(1)
Jun-19	(93)	0	24	24	(69)	(81)	2.20%	(0)		(1)
Jul-19	(69)	0	37	37	(32)	(51)	2.20%	(0)		(1)
Aug-19	(32)	0	44	44	12	(10)	2.20%	(0)		(1)
Sep-19	12	0	185	185	197	104	2.20%	0		(1)
Oct-19	197	0	95	95	292	244	2.20%	0		(0)
Nov-19	292	0	89	89	381	337	2.20%	1		0
Dec-19	381	0	84	84	465	423	2.20%	1		1
Jan-20	466	0	0	0	466	466	2.20%	1	1	1
Feb-20	466	0	0	0	466	466	2.20%	1		2
Mar-20	466	0	0	0	466	466	2.20%	1		3
Apr-20	466	0	0	0	466	466	2.20%	1		3
May-20	466	0	0	0	466	466	2.20%	1		4
Jun-20	466	42	0	(42)	424	445	2.20%	1		5
Jul-20	424	47	0	(47)	376	400	2.20%	1		6
Aug-20	376	47	0	(47)	329	353	2.20%	1		6
Sep-20	329	40	0	(40)	290	309	2.20%	1		7
Oct-20	290	36	0	(36)	253	272	2.20%	0		8
Nov-20	253	33	0	(33)	220	237	2.20%	0		8
Dec-20	220	37	0	(37)	183	202	2.20%	0		8
Jan-21	183	39	0	(39)	144	164	2.20%	0		9
Feb-21	144	37	0	(37)	108	126	2.20%	0		9
Mar-21	108	39	0	(39)	69	88	2.20%	0		9
Apr-21	69	33	0	(33)	36	52	2.20%	0		9
May-21	36	36	0	(36)	(0)	18	2.20%	0		9

EXHIBIT P-10
Schedule DGH-6E
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

ELECTRIC

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5E (Sales*Rate)	DGH-4E	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
LPLS										
Jan-19	0	0	(55)	(55)	(55)	(28)	2.20%	(0)		(0)
Feb-19	(55)	0	(54)	(54)	(109)	(82)	2.20%	(0)		(0)
Mar-19	(109)	0	16	16	(93)	(101)	2.20%	(0)		(0)
Apr-19	(93)	0	16	16	(78)	(85)	2.20%	(0)		(1)
May-19	(78)	0	29	29	(49)	(63)	2.20%	(0)		(1)
Jun-19	(49)	0	46	46	(3)	(26)	2.20%	(0)		(1)
Jul-19	(3)	0	56	56	54	26	2.20%	0		(1)
Aug-19	54	0	58	58	111	83	2.20%	0		(1)
Sep-19	111	0	191	191	302	207	2.20%	0		(0)
Oct-19	302	0	147	147	449	376	2.20%	1		1
Nov-19	449	0	105	105	554	501	2.20%	1		1
Dec-19	554	0	90	90	644	599	2.20%	1		3
Jan-20	646	0	0	0	646	646	2.20%	1	3	1
Feb-20	646	0	0	0	646	646	2.20%	1		2
Mar-20	646	0	0	0	646	646	2.20%	1		4
Apr-20	646	0	0	0	646	646	2.20%	1		5
May-20	646	0	0	0	646	646	2.20%	1		6
Jun-20	646	55	0	(55)	591	619	2.20%	1		7
Jul-20	591	63	0	(63)	528	560	2.20%	1		8
Aug-20	528	62	0	(62)	466	497	2.20%	1		9
Sep-20	466	52	0	(52)	414	440	2.20%	1		10
Oct-20	414	53	0	(53)	361	388	2.20%	1		11
Nov-20	361	49	0	(49)	313	337	2.20%	1		11
Dec-20	313	52	0	(52)	260	286	2.20%	1		12
Jan-21	260	55	0	(55)	205	233	2.20%	0		12
Feb-21	205	51	0	(51)	154	180	2.20%	0		12
Mar-21	154	54	0	(54)	100	127	2.20%	0		13
Apr-21	100	46	0	(46)	54	77	2.20%	0		13
May-21	54	54	0	(54)	(0)	27	2.20%	0		13

EXHIBIT P-10
Schedule DGH-6G
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

GAS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5G (Sales*Rate)	DGH-4G	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
RSG										
May-19	0	0	(137)	(137)	(137)	(68)	2.20%	(0)		(0)
Jun-19	(137)	0	(108)	(108)	(245)	(191)	2.20%	(0)		(0)
Jul-19	(245)	0	(1)	(1)	(246)	(246)	2.20%	(0)		(1)
Aug-19	(246)	0	6	6	(240)	(243)	2.20%	(0)		(1)
Sep-19	(240)	0	4	4	(236)	(238)	2.20%	(0)		(2)
Oct-19	(236)	0	7	7	(230)	(233)	2.20%	(0)		(2)
Nov-19	(230)	0	10	10	(219)	(224)	2.20%	(0)		(3)
Dec-19	(219)	0	21	21	(198)	(209)	2.20%	(0)		(3)
Jan-20	(198)	0	553	553	355	78	2.20%	0		(3)
Feb-20	355	0	488	488	843	599	2.20%	1		(2)
Mar-20	843	0	409	409	1,252	1,048	2.20%	2		0
Apr-20	1,252	0	235	235	1,487	1,370	2.20%	3		3
May-20	1,489	0	0	0	1,489	1,489	2.20%	3	3	3
Jun-20	1,489	0	0	0	1,489	1,489	2.20%	3		5
Jul-20	1,489	0	0	0	1,489	1,489	2.20%	3		8
Aug-20	1,489	0	0	0	1,489	1,489	2.20%	3		11
Sep-20	1,489	0	0	0	1,489	1,489	2.20%	3		14
Oct-20	1,489	67	0	(67)	1,423	1,456	2.20%	3		16
Nov-20	1,423	160	0	(160)	1,262	1,343	2.20%	2		19
Dec-20	1,262	249	0	(249)	1,013	1,138	2.20%	2		21
Jan-21	1,013	272	0	(272)	741	877	2.20%	2		22
Feb-21	741	245	0	(245)	496	619	2.20%	1		24
Mar-21	496	203	0	(203)	293	395	2.20%	1		24
Apr-21	293	105	0	(105)	188	241	2.20%	0		25
May-21	188	58	0	(58)	131	159	2.20%	0		25
Jun-21	131	41	0	(41)	89	110	2.20%	0		25
Jul-21	89	30	0	(30)	60	74	2.20%	0		25
Aug-21	60	29	0	(29)	30	45	2.20%	0		25
Sep-21	30	30	0	(30)	(0)	15	2.20%	0		26

EXHIBIT P-10
Schedule DGH-6G
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

GAS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5G (Sales*Rate)	DGH-4G	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
GSG										
May-19	0	0	(23)	(23)	(23)	(11)	2.20%	(0)		(0)
Jun-19	(23)	0	(20)	(20)	(43)	(33)	2.20%	(0)		(0)
Jul-19	(43)	0	0	0	(42)	(42)	2.20%	(0)		(0)
Aug-19	(42)	0	2	2	(40)	(41)	2.20%	(0)		(0)
Sep-19	(40)	0	1	1	(39)	(40)	2.20%	(0)		(0)
Oct-19	(39)	0	2	2	(37)	(38)	2.20%	(0)		(0)
Nov-19	(37)	0	3	3	(34)	(35)	2.20%	(0)		(0)
Dec-19	(34)	0	5	5	(29)	(31)	2.20%	(0)		(0)
Jan-20	(29)	0	87	87	59	15	2.20%	0		(0)
Feb-20	59	0	83	83	142	100	2.20%	0		(0)
Mar-20	142	0	70	70	212	177	2.20%	0		0
Apr-20	212	0	38	38	249	231	2.20%	0		0
May-20	250	0	0	0	250	250	2.20%	0	0	0
Jun-20	250	0	0	0	250	250	2.20%	0		1
Jul-20	250	0	0	0	250	250	2.20%	0		1
Aug-20	250	0	0	0	250	250	2.20%	0		2
Sep-20	250	0	0	0	250	250	2.20%	0		2
Oct-20	250	11	0	(11)	239	244	2.20%	0		3
Nov-20	239	22	0	(22)	217	228	2.20%	0		3
Dec-20	217	38	0	(38)	179	198	2.20%	0		4
Jan-21	179	46	0	(46)	133	156	2.20%	0		4
Feb-21	133	44	0	(44)	90	111	2.20%	0		4
Mar-21	90	37	0	(37)	52	71	2.20%	0		4
Apr-21	52	17	0	(17)	36	44	2.20%	0		4
May-21	36	9	0	(9)	26	31	2.20%	0		4
Jun-21	26	8	0	(8)	19	23	2.20%	0		4
Jul-21	19	6	0	(6)	13	16	2.20%	0		4
Aug-21	13	6	0	(6)	7	10	2.20%	0		4
Sep-21	7	7	0	(7)	0	4	2.20%	0		4

EXHIBIT P-10
Schedule DGH-6G
GEM Interest Calculation Example
Simple example of two-year cycle to calculate GEM interest and deferral balance; assume 2.20% interest rate (2 Year Treasury + 60 basis points)

GAS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Prior E - I	DGH-5G (Sales*Rate)	DGH-4G	= C - B	= A + D	= (A + E) / 2		= F * G		= Prior J + H - I
Month	Under / (Over) Recovery Beginning Balance ($000s)	Revenues Collected / (Credited) ($000s)	Deferral to Collect / (Credit) excl interest ($000s)	Under / (Over) Recovery ($000s)	Under / (Over) Recovery Ending Balance ($000s)	Under / (Over) Average Monthly Balance ($000s)	Interest Rate Annualized	Interest Income / (Expense) Average Monthly Balance ($000s)	Interest Roll-In ($000s)	Cumulative Interest ($000s)
LVG										
May-19	0	0	(15)	(15)	(15)	(8)	2.20%	(0)		(0)
Jun-19	(15)	0	(16)	(16)	(31)	(23)	2.20%	(0)		(0)
Jul-19	(31)	0	(3)	(3)	(34)	(33)	2.20%	(0)		(0)
Aug-19	(34)	0	(2)	(2)	(36)	(35)	2.20%	(0)		(0)
Sep-19	(36)	0	(2)	(2)	(38)	(37)	2.20%	(0)		(0)
Oct-19	(38)	0	(9)	(9)	(47)	(43)	2.20%	(0)		(0)
Nov-19	(47)	0	(14)	(14)	(61)	(54)	2.20%	(0)		(0)
Dec-19	(61)	0	(15)	(15)	(76)	(69)	2.20%	(0)		(1)
Jan-20	(76)	0	65	65	(11)	(44)	2.20%	(0)		(1)
Feb-20	(11)	0	65	65	53	21	2.20%	0		(1)
Mar-20	53	0	46	46	99	76	2.20%	0		(0)
Apr-20	99	0	13	13	111	105	2.20%	0		(0)
May-20	111	0	0	0	111	111	2.20%	0	(0)	0
Jun-20	111	0	0	0	111	111	2.20%	0		0
Jul-20	111	0	0	0	111	111	2.20%	0		1
Aug-20	111	0	0	0	111	111	2.20%	0		1
Sep-20	111	0	0	0	111	111	2.20%	0		1
Oct-20	111	7	0	(7)	104	108	2.20%	0		1
Nov-20	104	10	0	(10)	94	99	2.20%	0		1
Dec-20	94	15	0	(15)	80	87	2.20%	0		2
Jan-21	80	18	0	(18)	62	71	2.20%	0		2
Feb-21	62	17	0	(17)	45	53	2.20%	0		2
Mar-21	45	16	0	(16)	29	37	2.20%	0		2
Apr-21	29	9	0	(9)	20	25	2.20%	0		2
May-21	20	4	0	(4)	16	18	2.20%	0		2
Jun-21	16	5	0	(5)	11	13	2.20%	0		2
Jul-21	11	3	0	(3)	8	9	2.20%	0		2
Aug-21	8	4	0	(4)	4	6	2.20%	0		2
Sep-21	4	4	0	(4)	0	2	2.20%	0		2