HINGHAM MUNICIPAL LIGHTING PLANT

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Laura M. Burns, Chair
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Tyler Herrald, Secretary

REGULAR MEETING
HINGHAM MUNICIPAL LIGHT BOARD

February 14, 2023

Zoom Meeting
https://www.youtube.com/watch?v=Ge1rMzgKEKg

Meeting Called to Order

A regular meeting of the Board of Commissioners of the Hingham Municipal Light Plant (HMLP) was called to order by the Board's Chair, Laura Burns, at approximately 7:30 am on Tuesday, February 14, 2023, via Zoom.

Present:

Board Members:	Laura Burns, Chair Michael Reive, Vice Chair Tyler Herrald, Secretary
HMLP:	Thomas Morahan, General Manager Mark Fahey, Assistant General Manager Stephen Girardi, Engineering Manager Joan Griffin, Business Manager Ellen McElroy, Customer Service Supervisor Brianna Bennett, Sustainability Coordinator
Guests:	Mark Beauchamp – Utility Financial Solutions, LLC Michael Johnson – Utility Financial Solutions, LLC
Materials:	Utility Financial Solutions, LLC's Power Point Presentation titled: "Hingham Municipal Lighting Plant – Draft Electric Cost of Service Study"

Ms. Burns read the following disclaimer into the record:

This meeting is being held remotely as an alternative means of public access pursuant to Chapter 107 of the Act of 2022 and all other applicable laws temporarily amending certain provisions of the Open Meeting Law. You are hereby advised that this meeting and all communications during this meeting may be recorded by the Town of Hingham in accordance with the Open Meeting Law. If any participant wishes to record this meeting, please notify the chair at the start of the meeting in accordance with M.G.L. c. 30A, § 20(f) so that the chair may inform all other participants of said recording.

Ms. Burns asked if anyone other than HMLP wished to record the meeting. No one responded affirmatively.

Approve Meeting Minutes

Ms. Burns asked the HMLP Board members if they had a chance to review the minutes for the December 13th meeting. Both Mr. Reive and Mr. Herrald replied affirmatively. Ms. Burns wanted to make a few changes to the January 10th minutes:

1. On page 3, in the middle of the last paragraph, in the discussion of implementing the proposed opt-out rate, Ms. Burns commented that the phone survey would be interesting because she does not pick up the phone. Ms. Burns asked to strike that sentence because she was unsure what she was attempting to convey.

2. Under the Municipal Solar Project, in the last paragraph, the second sentence of that section reads that the legal counsel explained that we could not fund studies for things that we would own. It should be for something that we would *not* own.
3. On the next page, under "comments from the public regarding municipal solar," the word counsel is misspelled. It is spelled s-i-l, and it should be s-e-l
4. Mr. Reive made the suggestion to remain consistent when using kWh. And to also add Steve Girardi's name to the minutes.

Motion: Mr. Reive moved to accept the minutes from December 13, 2022 and January 14, 2022 as corrected. Mr. Herrald seconded the motion.

Roll Call Vote:
Mr. Reive: Aye
Mr. Herrald: Aye
Ms. Burns: Aye

Vote to Appoint Paul Hibbard to ENE Board as an outside Director

Ms. Burns then said the next item on the agenda is to place a vote for Paul Hibbard, who has been proposed as an outside Director for Energy New England. She asked if the HMLP Board is voting on this based on their role as the Light Plant being a part owner of Energy New England. Mr. Morahan affirmed that is correct. Ms. Burns asked Mr. Reive and Mr. Herrald if they had a chance to review Mr. Hibbard's CV and if they were prepared to vote. They both responded affirmatively.

Motion: Mr. Reive moved to approve the appointment of Paul Hibbard to the Energy New England Board as an outside Director. Mr. Herrald seconded the motion.

Roll Call Vote:
Mr. Reive: Aye
Mr. Herrald: Aye
Ms. Burns: Aye

Mr. Morahan asked Mr. Herrald to come to the Light Plant to sign this paperwork for Paul Hibbard.

Rate Study – Utility Financial Services

Ms. Burns transitioned to the next agenda item, the discussion cost of service study by Utility Financial Solutions, LLC (UFS). Mark Beauchamp and Michael Johnson were present on the meeting to make the presentation to the Board. Mr. Beauchamp is presenting the results of the Cost-of-Service Study and looking for feedback on three areas:

1. The rate track that UFS has projected. Mr. Beauchamp notes that this includes a costly transmission project and HMLP's preparation to issue bonds for that project.
2. The cost-of-service results, which look at how much it costs to provide service to each rate class of customers and how much the projected revenues are. Mr. Beauchamp says this will identify interclass subsidies and provide guidance on how to move rates closer to cost of service. This is intended to balance the financial health of the utility with customer impacts.
3. The customer charge. Mr. Beauchamp notes that this is a controversial piece of a rate design. He intends to go through what a customer charge consists of and talk about the strengths and weaknesses.

As a part of this discussion, Mr. Beauchamp wants to include industry rate trends and what is happening around the country. He emphasizes that utilities are modernizing their rates and moving forward with more advanced rate structures, like time of use. They are trying to incentivize certain types of usages, like electric vehicles, to move them off-peak to help save them money and help reduce carbon emissions.

[Mr. Beauchamp shared UFS's Power Point, "Hingham Municipal Lighting Plant – Draft Electric Cost of Service Study"]
(What follows is a summary of Mr. Beauchamp's presentation.)

Slide 1: Introduction
UFS was formed in 2001 and has done work in 44 states, including several Caribbean Islands. UFS has done Cost of Service and Financial Planning studies for American Public Power Association. They have about 400 municipal clients in the United States. They have conducted these studies extensively and will discuss trends they see in the U.S.

Slide 2: Objectives
The review revenue requirements determine how much the utility needs to recover in rates to pay their bills. This includes the cost of operations, maintenance, capital expenditures, and debt service. Those items form the revenue requirements, and then the rates need to cover those requirements. Mr. Beauchamp explains that he will then go over the cost-of-service results and the rate adjustment plan.

Slide 3: Technology Impacts on Hourly System Usages
Mr. Beauchamp explains that many things are happening in the industry regarding technology changes like solar, EVs, and electrification. He said the question becomes how to design or develop rates to take advantage of this technology in a manner that is good for HMLP and helps gives customers more control of their electric bills. The presentation slide shows a blue line representing a typical usage pattern for a utility. He notes that the loads are lower in the early evening hours. Most utilities tend to peak at about 7 PM or 8 PM, and residential customers are driving these peaks. Mr. Beauchamp explains that we are building infrastructure to provide service to customers. The more efficiently and consistently customers use the infrastructure, the lower our costs will be because we are getting more sales for the investments that we have made. Utilities are trying to improve their system load factors, and the new technologies can help achieve that. In the example shown by Mr. Beauchamp, the utility peaks are at 7 PM/8 PM. Two things need to happen to improve that usage pattern or load factor: lowering the peak (higher usage times) and filling in the valleys (lower usage times).

Mr. Beauchamp offers a specific example using solar as a new technology on the system. Solar tends to produce energy in the afternoon and lower the utility's load factor. This is because it is producing when the system does not necessarily need the energy production. If solar were to produce during peak hours, it would lower peak demand. To address this, utilities are trying to incentivize battery installation. Mr. Beauchamp notes that batteries can be expensive, but when they are installed, the solar production tends to go into the battery. This thereby increases the sales during this low-usage period of time. Then, batteries are discharged at the time the system peaks, which tends to improve the system load factors.

Another technological example noted by Mr. Beauchamp is residential EVs. By the end of the decade, it is predicted that 20-40% of new car sales will be electric, and 21% of the electric sales will be in the transportation sector by 2050. Sending residential customers, the proper price signal to charge during the off-peak hours will fill the valley periods. But if we do not offer the right price signals, with respect to time of use rates, customers will charge their vehicles during peak hours.

Mr. Beauchamp also mentioned commercial electric charging stations. He notes that Tesla EV charging stations, for example, are 350 kW /port. This can be a substantial load for a utility, and they tend to charge from 5 AM/6 AM to 10 PM at night. Utilities are trying to move to managed charging. Managed charging is when a utility will throttle back the charging from 350 kW to discharging only 170 kW – the customer can still charge their vehicle, but the utility will be able to control when it is being charged. So, during the peak hours of the day, the utility can manage that load by throttling back the charging stations. Many utilities in the U.S. are moving towards managed charging stations. Ms. Burns asks if this means the utilities will make less energy available at the charging stations so that people can charge and it will take longer to charge. Mr. Beauchamp said yes, that is correct.

Energy efficiency programs started in earnest about 20 years ago with energy-efficient appliances, washers, dryers, and thermostats. Energy efficiency lowers a customers' kWh consumption. However, it lowers their usage at the time of the system peak at a greater percentage than it reduces kWh. In other words, it has a greater impact on lowering these demands than it does at reducing kWh. A typical residential customer has a load factor between 17-20%, which is not very good. When energy efficiency programs are implemented, the load factors go into the mid to high 20's. Energy efficiency programs are good for both the customers and the utilities. Utilities are putting rebate programs in place to incentivize customers to implement projects and purchase energy efficient appliances to help reduce usage during these peak hours.

Mr. Beauchamp then discusses dynamic pricing which is time of use rates. Time of use rates will give the customer incentives to use energy during the "valley" hours rather than during "peak" hours/high-cost periods. When utilities implement time of use rates, they send a certain price signal. Usually this is a 2 -1 ratio between on-peak and off-peak (for example, charging 20 cents on peak and 10 cents off peak), and utilities get anywhere from a 6-12% reduction from those customers during the peak hours of the day. This is all part of price elasticity. It is not so much an immediate response by customers, but a long-term response. When you start sending these price signals, customers will start to react to the price signals and purchase devices that enable them to conveniently shift their usage to lower cost time periods. Mr. Beauchamp believes that this price elasticity of demand will more than double over time, 5 to 10 years, between when it is implemented to when you see the full effect of time of use.

Then, Mr. Beauchamp describes the impact of the electrification of buildings and how several states, including some MA communities, are setting requirements that new builds (residential and commercial) cannot extend the natural gas lines. Utilities around the country are offering electrification programs for things like, heat pumps, to promote electrification, because there are lower carbon emissions with electricity than natural gas. Promoting electrification gets back to proper incentivization with price signals and time of use. When buildings move to electric heat, they tend to improve the usage during these "valley" periods. And it is during these valley periods that renewables, like wind, tend to be generating and more efficient generating units are operational. During peak hours, less efficient units are operating which produce more carbon because the heat rates in those units are not as good.

Mr. Beauchamp reflects that this slide is very technical, but it shows how the different technologies and rates can comingle together to lower customers' costs, give them more control over their bills, and help the environment.

Slide 4: Historical Establishment of Rates
Previously, customers were placed into rate classes based on similar usage patterns and customer requirements:

- Customer Load factors
- When energy was used
- Metering requirements
- Service levels

Back in 1890 customers were billed for electricity by counting the number of appliances and light bulbs in their homes. Then, utilities installed meters that recorded how much a customer used and billed on usage. In 1906, they developed demand recording meters which recorded a customers' peak usage over a month. These mechanical meters were very expensive so they were only used for very large customers, because of the cost. In 1970, Solid State metering was introduced and developed where we could record a customers' hourly usage pattern. However, when Solid State metering was first offered, it was very expensive. Only until the last 10 years did the solid-state metering become more economical to install for most customers. Right now, in the U.S. 73% of residential homes have these meters.

Ms. Burns asked Mr. Beauchamp to explain demand/demand charges. Mr. Beauchamp explained that when customers use energy throughout a month, sometimes they draw only a little, sometimes they draw more. Demand metering records a customer's peak usage during that month, which is the peak draw or demand they have created on the system. It is usually called an integrative demand which is an averaging over a 20-30-minute time period. That peak represents the impact the customer is having on the distribution infrastructure. We have to have a transformer sized to handle that customer's peak usage/demand.

The demand charge that you bill upon consists of three components.
1. Recovery of your distribution infrastructure, because it is an indication of their impact on distribution
2. It recovers transmission impacts, because transmission is charged to us based on the utility's peak that occurs
3. Power supply capacity requirements

These three components are recovered through demand charges.

Ms. Burns asked, "when you look at capacity charges, our capacity charges are based on the size of our entire rate base, but really only these large commercial customers are actually being billed for as a separate item?' Mr. Beauchamp replied, "Correct." She asked, "Did cost of service tend to assign all the capacity to the industrial customers, because you could meter them, or was there an assumption about the other customers and you would assign some of the capacity to them?" Mr. Beauchamp said some of the capacity is assigned to all customers. In the cost-of-service study, they use load research, where we identify how each customer class uses how and when they use electricity.

About 20 years ago we started to see changes in usage patterns, especially with residential. Residential customers are between a 17 and 20% load factor but what we noticed is when they put in place energy efficiency programs, their load factors went into the high 20's. We were actually over charging them because the rate was developed based on that 17-20% load factor, but they have a higher load factor, so it costs less per kWh to provide them with service.

The definition of load factor is a ratio between a customer's average usage in a month. It is the average divided by the peak. So, the higher the load factor, the more efficiently they are using infrastructure.

Ten years ago, we started putting in solar and solar had the opposite effect. Solar lowered the customer's load factors down to below 12%. Their usage pattern did not fit with the typical residential load profile. Then, with EVs we had the opportunity to improve our system load factors and to send them the appropriate price signals to use that energy during off peak time periods. What time of use rates do is charge customers more accurately. Let's say the cost-of-service study appropriately recovers costs from the residential class. All that means is that the total class is recovering the revenue requirements, but within the class you may be having inter-class subsidies. In other words, some customers are undercharged and some customers are overcharged. Time of use rates corrects that inter-class subsidization that is occurring.

Slide 5: Major Rate Design Changes
What we are seeing around the United States as far as trying to make the rate structures more accurate with demand charges, we try to put more customers on demand charges especially the smaller commercial customers. Some utilities use real-time pricing rates for very, very large customers. Real -time pricing looks at how much that customer is using at the time of your transmission peaks and that amount is passed on directly to them. Real-time pricing rates are probably the most accurate. Utilities are moving towards these real-time pricing by primarily the time-based rates, time of use.

Inverted Block rate structures are rates that increase with increased usage. For example, the first 500 kWh are priced at 10 cents, anything above that is priced at 15 cents.

Customer Charges based on size of service – you have customers that have single phase service and some that have three phase and when they have three phase service, it is more expensive to do the metering. They have higher minimum requirements on the distribution system. Utilities are trying to set these customers' charges based on size of service.

Review Line Extension Policies: When you add new customers to your system, the question becomes, how much should the utility pay for that extension and how much should the customer pay. When the system grows, you want growth to be good for everyone but you want to be fair to the new customer – so you need to look at contribution margin or identify the value of a customer.

Ms. Burns asked Mr. Morahan if HMLP has a line extension policy. Mr. Morahan said we charge the customer for line extensions.

Mr. Reive asked about the time of use rates across the country, and asked when is it less expensive, when is it more expensive? Mr. Johnson said HMLP's peak hours are from 9am to 8pm for winter and for summer months, 2:00pm to 7pm.

Slide 23: Utility Costs Compared with Utility Rates
Mr. Beauchamp said when it comes to time of use rates you have to be careful as it is really difficult to go from where you are with the flat rate structures directly to the full time of use rates. You don't want to create customer dissatisfaction so we developed a plan where we adjust the peak and off-peak rates in 3 phases to try to slowly move customers to the time of use rate. This gives customers time to react and understand that price signal and to purchase the enabling devices to help them to shift their usage.

Utilities generally have small, medium, and large general service rates and they are looking at reviewing these rates to be more accurate within those rates. This would mean setting a small commercial rate that has a demand charge, but a demand charge that fits their usage profile, to be more accurate to try to reduce the inter-class subsidization that can be occurring in certain rate structures. These are the trends that are happening around the United States.

Mr. Reive asked: The Interval Block rate structures, is that common for residential type usage? We have a similar type system for our water where your first number of gallons is one price and then you slightly pay more for more over that. Mr. Beauchamp said it is becoming more common; "I think 90% of utilities in California have inverted block rates structures." It is becoming more common throughout the United States and there is a cost-based reason for it. Mr. Beauchamp says he will address this more in depth when he gets to the customer charge.

Slide 6: Significant Assumptions
One of the things UFS does as part of our studies is to develop a long-term financial plan. We are just showing 5 years, here. When you start projecting cost you have to base it on certain assumptions. Inflation was running about 8.6 last year and it is down around 7 % now but for 2023 we have assumed an inflation rate of 5%, 5 % in 2024 and then a more normalized inflation rate closer to the historical averages around three percent. We also assumed a slight growth rate a half percent. This is the projected change in purchased power cost now. Purchased power cost changes do not really affect HMLP financially because of the power cost adjustment. Any changes in power supply costs are passed on to customers. There is a timing difference that occurs, but it is passed on to rate payers automatically. Basically, we could make this number 3% or 10%, it would not affect our recommendations.

The capital plan is what is driving most of what you are seeing coming up. Your capital plan is about 5.6 million in 2023, small capital plan in 2024, but in 2025 we are looking at the transmission investment.66 million dollars, and then 7 million dollars in capital expenditures in '26 and '27. In order to fund this 66 million, we are looking at issuing about a 45-million-dollar debt issuance, and in our modeling, we assume the 20-year Bond issuance with a 5 % interest rate.

Slide 7: COS Summary Financial Results
When we modeled HMLP's financials, there are three key financial targets we look at to help ensure that the utility is financially stable.

1. Debt Coverage Ratio. When you issue debt, it is revenue bonds, which are different than General Obligation Bonds that a city may issue. General Obligation Bonds are secured by the property taxes of the community. Revenue Bonds are secured through the revenues of the utility. When you issue Revenue Bonds, they come with bond covenants which require typically that you maintain a coverage ratio of 1.2 times. Coverage ratio is the cash that is generated through your operations (excluding Capital Investments) divided by your debt service payment. If you fall below what is specified in your bond ordinance, you're in technical default on the debt. If this happens, the next time you go to issue debt your bond rating could be affected by that. So, it is important that we maintain the debt coverage ratio. Our target is 1.4 coverage, minimum. We want to make sure a utility stays above a 1.4 coverage. Now, what you see here is that debt issuance your coverage ratios are way below the 1.4, you are at .46 and actually negative '26 and '27, of course this is without any rate adjustments.

2. The second target we look at is cash reserves. We identify the minimum level of cash that the utility should maintain in order to fund your working capital needs, and that is about 14 million in 2023. It goes up each year to about 17 and a half million in '27. In your projected cash reserves, you are very healthy, currently at about 33, 34 million projected. But with the debt issuance and the investment and transmission, your cash would start to drop to about 11 million then it actually falls negative in '26 and '27. We want to make sure that the rates keep your cash reserves above that minimum.

3. Even though a municipal electric system is not-for-profit we still have to make money to break even. And the reason we have to make money to break even is that we are making investments in infrastructure and eventually, we have to replace that infrastructure. And every year the replacement costs of the assets increase. In order to break even we need to recover the inflationary increase in our assets' replacement costs. That amounts to about two million dollars and it goes up to about 4 million. But we use this more as an upper boundary. We do not want to exceed that target operating income because if we

exceed it, that means we are overcharging our rate payers. Here we are establishing a minimum and an upper boundary for operating income. When we set the rate track, we want to stay between the minimum and that upper boundary. Looking at your projected adjusted operating income, there are operating losses projected; a 1.3 million operating loss in '23, increasing to 8.7 million in 2027.

Ms. Burns had a couple of questions referring to the capital plan slide. When you look at a target income how does that relate to HMLP's 8 percent statutory limitations on how much we can make. Mr. Beauchamp said HMLP is well below that. Ms. Burns then commented that we think the transmission line project is going to cost an estimated 66 million or more. We are showing a $45 M bond issuance and if we want to stay flat, we are short 20 million dollars. Ms. Burns asked if this projection includes the use of the depreciation fund and other funds for buying down what we are going to have to borrow. Mr. Beauchamp said, yes, we are funding around 20/21 million dollars with your cash. Ms. Burns continued, so the capital plan is probably going to be driving these rate increases and the vast bulk of that is the transmission project. I'm not qualified to look at the capital plan and say, yes, we need to do this and no we don't need to do that. That is the job of Mr. Morahan and his staff to make those decisions, but the capital plan was developed without any context of what rate increases might be required to fund that capital plan. So, it is possible that we might want to go back to that capital plan, if we're looking at 6 % rate increases over the next few years and say, and ask if there any of this we can postpone so as to smooth out the rate increase. Mr. Morahan said it is something we can look at. He went on to say that this year we have some major projects with the transmission line. We have to replace the insulators, which was an unplanned event. We have to replace three wooden poles for woodpecker damage, which is a significant cost. Another significant project is our SCADA project -- we are installing a SCADA system with the new fiber installed by the town. We are going to utilize that fiber. Mr. Morahan suggested that we can look at the Capital projects this year and see if there is anything we might want to delay. Mr. Beauchamp said it is really easy to model any sensitivities HMLP may have, so if you did delay the capital plan, we can easily model that and redevelop the rate track. It is quite an easy process.

Slide 8: Debt Coverage Ratio
Mr. Beauchamp went on to explain that the debt coverage ratio is the amount of cash that is generated through operations divided by projected debt service payments. In 2023, that cash generated by operations was 2.2 million and in 2025 it is 1.6 million. The projected debt service payment in that year is 3.6 million. Mr. Beauchamp points out that the cash is not sufficient to fund the debt service payment. This debt coverage ratio is 0.46 and the minimum is 1.4. There are different ways of calculating the debt coverage ratio, but this is the most common way it is determined.

Slide 9: Minimum Cash Reserves
Then, Mr. Beauchamp explains that we want to make sure that the utility has enough working capital to pay its bills in a timely fashion, because there is a working capital lag between when you pay a bill and get money from customers. Pretty much any utility that bills monthly has a 45-day working capital lag and if you took 45 days and divided it by 365 that is 12.3 %. We want to make sure we have 45 days of working capital to fund the operation maintenance of the utility. Then there is purchase power, which fluctuates throughout the year. We want to make sure your highest purchase power bill is in your cash reserves at all times. Your debt service payments: we want to make sure your highest debt payment throughout the years in your reserves – it does not show up here until 2025. Capital improvement program, less any debt proceeds: We want to make sure you have enough cash in your reserves to fund your capital improvement programs that is planned for that year. So, we smooth it out. We take your five-year Capital plan less your debt proceeds and basically divide it by 5. And that means we need to have 8.5 million in reserves to fund our Capital Improvement Program.

When there is an unexpected event, i.e., ice storm, windstorm, hurricane you want to make sure you have enough cash in your reserves to start the repair and replacement process. To recognize this, we look at the age of the infrastructure. If you have a newer infrastructure, you have less exposure to something unexpected occurring to it, compared to an older infrastructure. HMLP has an older infrastructure compared to other Municipal systems so we have assigned you the highest risk rating with respect to something unexpecting occurring to your infrastructure and that is adding about 2.3 million dollars to your cash reserve requirements. Once you get that 66-million-dollar capital investment in service the age of your infrastructure drops to 41 % on average.

Slide 10: Target Operating Income
We are trying to recover the inflationary increase in asset replacement costs. We look at the net book value, 25 million, and adjust it by the 3.2 percent inflation rate and by the age of the infrastructure. HMLP's assets are 66 % depreciated, so the result of that calculation is 9.14%. That is an upper boundary which we don't want to exceed in setting a rate structure.

Slide 11: Projected Rate Track
We are projecting 6% rate adjustments based on the capital plan. The recommended minimum cash is about 14 million and you can see that we are good for the first 4 years. In year 4, we drop below it. When it comes to capital, there is always shifting occurring. Mr. Beauchamp notes that he does not want to be overly aggressive with the increases up front to prepare the utility for that 66-million-dollar project. He set the increases for the first three years at 6%, and in 2026 we will need to evaluate if the 6 percent needs to go up a little higher in order to get the cash reserves above that minimum. The debt coverage ratio in 2026 is projected at 1.05, which is below the 1.4 coverage, but the next year, 2027 we jump back up. Mr. Beauchamp said he is not overly aggressive at it at this time.

When you have increases at less than 5%, customers view this as inflationary adjustments. Increases between 5 – 10 % this tend to be acceptable to residential rate payers but you get some backlash from large users. But what you are trying to avoid in setting a rate track and looking long term are the double-digit rate increases. Those are the ones that get the utilities in trouble. What we are proposing, based on the plan, is 6 % increases for the next three years, based on the direction of the Board and then have the plan updated prior to 2026.

Slide 12: Cost of Service Summary Results
This is how much it costs to provide service to each class of customers. To meet that target operating income, we would have an 18% increase. We are not proposing that, actually we would be getting the 18% over the next three years. But what this slide shows is how each class needs to change to meet its cost-of-service requirements. The residential class shows a need for a 20 increase to meet the cost-of-service requirement but the system averages 18 percent. What that tells me is your residential rate, in relation to all the other rates is actually pretty close. Most of your rates are in pretty good shape, other than street lighting and this is not that unusual. Town street lighting shows the need for an 86 % adjustment, almost a doubling of the rate. But that is a very small rate class. We probably want to give them an 8% increase. Small General Service is close to the system average. Large General Service Customers are even slightly less than the system average. Some of the classes would go up 6 % and some of them less than 6 percent.

Mr. Beauchamp asked the Board, if we get a rate increase like that 6 % how much leeway or bandwidth would you allow me to move these classes closer to cost of service. Usually, we ask for a plus or minus 2%. No class would get an increase greater than 8% and the minimum increase in any class would be 4 percent. And, we would work within that bandwidth in establishing the rates

Slide 13: What is a Customer Charge?
When a customer has a meter installed on their home or facility, the electric utility had the cost to install the meter, and the responsibility to repair it and replace it. Every month they have to read it and send the customer a bill and they have to maintain the service drop going into the home. Those are fixed costs that do not vary based on consumption, when they should be recovered in the customer charge. That part of it is not controversial. The part that is controversial is that we have to have a wire that extends from the substation to the home or the facility and without that wire we cannot deliver electricity. The question becomes, how much of that wire should be recovered through the customer charge and how much should be recovered through the usage component?

In a cost-of-service study, we did a minimum system analysis. We look at the minimum sizing requirement of your utility and how much it would cost to build that minimum sized infrastructure, and we roll that into the customer charge. Obviously, customers use more than the minimum amount. So, we have to have a bigger distribution system than the minimum sizing so that amount, the cost related to oversizing, is recovered through the usage component – for residentials it is kWh and for large industrials, it may be demand. This part is controversial because, when we do a minimum system analysis there is a certain amount of capacity that rolls into that. For example, that minimum sizing may be able to handle 500 kWh a month for residential service. If we roll all of that into the customer charge and we still have a usage charge for oversizing, then we are actually overcharging that customer for the first 500 kWh. In a sense they are being double charged for that infrastructure. They are paying for the minimum sizing that can handle the 500 kWh in the customer charge and they're also paying the oversizing in the first 500 kWh. This is the reason why utilities are trying to move toward inverted rate block structures to prevent overcharging.

Slide 14: Why is a Customer Charge Needed?
Mr. Beauchamp advanced to the next slide and explained why utilities do not keep the customer charge lower. The utility needs an appropriate customer charge for many reasons. One of the driving issues is making sure that year-round customers are not subsidizing seasonal customers. A customer charge stabilizes your revenues and reduces the seasonal subsidies, but it will also adversely impact low-use customers. This will adversely impact some low-income customers, but not all of them, because not all low-income customers are low-use.

Slide 15: Average Residential Usage Compared with Low-Income
The average use for this utility is 500 kWh. Most of the low income use less than that system average. About 1/3 use more than the system average. Governing bodies or the public sometimes say they are opposed to customer charges because low-income customers are adversely impacted. On average, they are, but some are not. Some of them benefit from a higher customer charge because it keeps the energy rate lower so you see 1/3 of these low-income customers actually benefit from setting the customer charge at a higher level. What many utilities do is establish low-income programs to help low-income customers to catch up.

Slide 16: Monthly Customer Charges
The customer charge is currently \$8.86. The Cost-of-Service study shows that it should be \$26.77. Mr. Beauchamp asks how much the Board is willing to increase the customer charge. We are asking for a \$2.00 increase each year, from \$8.86 to \$10.86 to \$12.86 to move towards the \$27.00. These customer charge increases balance the proposed 6% rate increase. Ms. Burns says that presumably UFS has HMLP's annual revenue requirement and if the customer charge is raised for each year, then the amount needed on the usage bill would go down. She asks if that implies that the rates would be changed for usage each year. Mr. Beauchamp responds that it would be, to balance the rate to the 6% increase. There would be a \$2 increase in

the customer charge and then the usage charge would be balanced 2% or so to meet the needs. Ms. Burns and Mr. Beauchamp reaffirm that the usage charge would change each year if the customer charge goes up.

Mr. Herrald asks if we need to be mindful to set the increase of the customer charges above inflation to catch up. He inquires whether these customer charges are increasing with the rate of inflation, or should we assume that they should be, so that if we are trying to catch up to them, we will have our increases higher than that inflationary rate on the customer charge. Mr. Beauchamp said he is correct, but there is more that affects this $27. It reflects not only inflation but also investment in the infrastructure. UFS is asking the Board to increase the charge by $2 each year. By doing this, the energy rate would not see as large of an increase.

Mr. Reive commented that the customer charge is to bring the first kWh to your home, but some homes are much bigger than others and some people's usage is larger than others. He asks if it is fair to appropriate a certain amount equally across the entire customer base when there is a big difference in people's total kWh hour usage in a year. Mr. Beauchamp said the rate design is going to show the increase both in percent and in dollars based on different uses. For example, if it is 200 kWh they might see an eight percent increase which equates to maybe $2.25; at 2000 kWh, they may see a 5% increase, but their bill may go up 10 dollars. We will give the Board that information once we give you the rate design so that the you can make an informed decision**.**

Slide 17: Next Steps
Mr. Beauchamp summarized that they are suggesting a 6% increase with a plus or minus 2%. The largest increase any class would get would get is 8% and the smallest, 4%. Mr. Beauchamp believes that customers are likely going to see increases between five and seven percent. Implementing a low-income discount would the low-income customers and help them out. The Customer Charge would increase it by $2.00 each year, as part of a three-year rate plan. We would suggest a commercial EV charging station rate and a residential all-electric rate. In the next meeting we can discuss time of use rate. Ms. Burns said she has many questions about Time of Use rate, but she wants to be aware of the time left in the meeting. The Board agreed to return to this discussion at the next meeting.

The UFS presentation concluded.

<u>Customer Survey Update</u>

Ms. Burns mentioned the customer survey update and asked when we can discuss that. Mr. Morahan said HMLP is meeting with the survey company next week and will provide the Board with some feedback.

<u>Motion to Adjourn</u>
Ms. Burns concluded the meeting and asked for a motion to adjourn.

<u>Motion</u>: Mr. Reive moved to adjourn the meeting. Mr. Herrald seconded the motion.

<u>Roll Call Vote</u>:
Mr. Reive: Aye
Mr. Herrald: Aye
Ms. Burns: Aye

The meeting adjourned at approximately 9:30am.