STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 18-0974-TF

Tariff filing of Green Mountain Power Corporation requesting a 5.45% increase in its base rates effective with bills rendered January 1, 2019, to to be fully offset by bill credits through September 30, 2019

PREFILED DIRECT TESTIMONY OF

KEVIN J. MARA

ON BEHALF OF THE

VERMONT DEPARTMENT OF PUBLIC SERVICE

August 10, 2018

Summary: Mr. Mara presents the Department's position with respect to the accuracy of Green Mountain Power's cost estimating procedures based on the "known and measurable" standard and questions the necessity of several facilities proposed for construction by Green Mountain Power. Mr. Mara recommends that the Commission adjust GMP's 2019 blanket work orders by $12,158,446 and also disallow $1,482,011 of the transmission and $4,595,459 of distribution projects included in GMP's rate filing.

Mr. Mara Sponsors the Following Exhibits:

Exhibit PSD-KJM–1	Professional Resume of Kevin J. Mara
Exhibit PSD-KJM-2	*Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*
Exhibit PSD-KJM-3	ICE Calculator Results Report for Hartland Line 9 & 901
Exhibit PSD-KJM-4	Transmission Lines - Cost Reductions Summaries
Exhibit PSD-KJM-5	Distribution Lines - Large, Cost Reductions Summaries
Exhibit PSD-KJM-6	Town of Brandon Utility Relocation Agreement
Exhibit PSD-KJM-7	GMP Distributed Resource Interconnection Guidelines
Exhibit PSD-KJM-8	GMP’s Response to PSD Discovery Request DPS1.Q44
Exhibit PSD-KJM-9	Summary of Cost Reduction – Blanket Work Orders
Exhibit PSD-KJM-10	Summary of Modified Cost Reduction – Blanket Work Orders

Direct Testimony
Of
Kevin J. Mara

Q1. Please state your full name, address, and occupation.

A1. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am a Vice President of the firm GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering. I am a registered engineer in Virginia as well as 20 other states.

Q2. Please outline your formal education.

A2. I received a degree of Bachelor of Science in Electrical Engineering from Georgia Institute of Technology in 1982.

Q3. Please state your professional experience.

A3. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services to publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC. In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line

Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am a Vice President of GDS Associates. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

Q4. Have you testified before any regulatory commissions?

A4. I have submitted testimony before the following regulatory bodies:

- Federal Energy Regulatory Commission ("FERC")
- District of Columbia Public Service Commission
- Public Utility Commission of Texas
- Maryland Public Service Commission
- Corporation Commission of Oklahoma

I have also submitted expert opinion reports before United States District Courts in California, South Carolina, and Alabama.

Q5. What are your qualifications to provide testimony before the Commission?

A5. I have more than 30 years of experience as a planning and distribution engineer specializing in electric utility systems. In this capacity as a distribution engineer, I have assisted electric utilities in the design, construction, and planning of their electric distribution systems. This work has included development of distribution system over-current protection, over-voltage protection, reliability improvements, and planned system upgrades. I have worked for electric utilities from Florida to Alaska in many different operating environments, and I have experience in a very diverse array of utility designs and operations. My curriculum vitae are attached as Exhibit PSD-KJM–1.

Q6. Would you please describe GDS?

A6. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; and Madison, Wisconsin. GDS has over 170 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly-owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q7. For whom are you appearing?

A7. I am testifying on behalf of the Vermont Department of Public Service ("Department" or "PSD").

Q8. Were your testimony and exhibits prepared by you or under your direct supervision and control?

A8. Yes, they were.

Q9. Can you explain the difference between the interim period and rate period as they relate to transmission and distribution plant additions?

A9. Yes. Calculation of the rate base value begins with the actual value as of December 2017. There is an adjustment for the interim period (October 1, 2017 – December 31, 2018) for rate base additions. There is also a rate base adjustment for the nine-month rate period 2019 (January 1, 2019 – September 30, 2019). Green Mountain Power ("GMP") used actual costs for the test period January 1, 2017 to September 30, 2017. GMP then made, what GMP deemed, known and measurable changes to these costs so that the net costs reflect the projected level of net costs that will occur in the rate period.[1] Costs for these two periods are provided by GMP and, for some projects, include actual costs through December 2017.

Q10. Do these costs include capital expenditures for growth of plant to serve new customers?

A10. Yes. In the previous rate case, GMP used a methodology to exclude growth from all individual projects and blankets for the interim and rate periods. This is because GMP

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[1] Ryan pf. at 7, lines 3-7.

based the rate period costs on actual costs in a test period and excluded the revenue associated with growth from new customers.[2]

In this filing GMP is using a different methodology. GMP is using a forecast that anticipates future load and includes new revenue associated with new customer growth. Therefore, plant additions for customer growth is included in the rate base.

Q11. Is there a summary of the T&D additions for the interim period and rate period?

A11. Yes. Mr. Fiske's Direct Testimony included Exhibit GMP-JRF-2 which summarizes the transmission and distribution assets additions to plant. This summary is purportedly supported by the individual cost estimates for each T&D project according to the requirements of the Memorandum of Understanding between the Department and GMP that was adopted by the Commission last year in Case 17-3112 (the "17-3112 MOU"). However, the values for the interim period in Exhibit GMP-JRF-2 for transmission lines are $90,000 higher than Mr. Fiske's summary table in his testimony.[3] There appears to be a $90,000 error in his calculations. Summing the values in Exhibit GMP-JRF-2 the total additions requested by GMP for the Interim period is $63,672,000 and $33,612,000 for the rate period as shown in the summary table.

[2] Fiske pf. at 11, Line 12 through Page 12, Line 1.
[3] Fiske pf. at 11, Line 4.

Q12. Explain your understanding of "known and measurable" standard in a traditional rate case before the Vermont commission.

A12. The standard practice is for an electric utility to prepare a cost-of-service filing that is based on an historic test year adjusted for known and measurable changes. For projects that are not complete and in service, it is necessary to document the plant value of the asset to be built/completed in the future during the period in which the rates (effective rate period) will be in effect (the adjusted test year). It is my understanding that based on the 17-3112 MOU, these support documents require a project cost summary that provides an itemization of the cost elements of the project, including supporting documentation (vendor quotes, resource estimates based on similar project, etc.).[4]

The Commission's standard for known and measurable is "changes that are measurable with a reasonable degree of accuracy and have a high probability of being in effect in the adjusted test year."[5] Further the Commission requires some "tangible work-product that shows that the project is likely to actually be completed; examples include work orders, cost-benefit analyses, or other types of written support for a project's cost and completion date."[6]

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[4] 17-3112-INV MOU, Exhibit 2, page 2 of 3.
[5] *GMP Rate Case*, Case No. 17-3112-INV, Order of 12/21/17, at 12.
[6] *Id.*

The documentation and justification of projects are at issue in this rate case to verify that the individual projects are known and measurable for ratemaking purposes and also to demonstrate that the proposed capital investments during the effective rate period will be necessary and reflect appropriate least-cost planning principles.

Q13. Is the rate payer at risk for the "known and measurable" standard?

A13. Yes. Utilities need to strictly adhere to budgets for projects included in the rate period. However, all construction projects are prone to volatility in cost due to uncertainties in the site conditions, weather, customer interaction, etc. Thus, the trend in the utility industry is to capture contingencies that can cause a project to go over budget. Often the use of contingencies result in an estimate that is too high. So, the risk to the rate payer is the need for a known and measurable estimate of the plant to be constructed that is higher than the actual construction cost when the plant is placed in service. Further, there is risk related to the timing of completion of the project. There are obstacles such as environmental permitting, easement acquisitions, material supply delays, etc., which can delay or indefinitely defer a project.

Q14. Is there a standard format to be used by GMP for known and measurable additions to the rate base?

A14. Yes, as I noted above, the 17-3112 MOU sets out documentation requirements for satisfying the known and measurable standard. In relevant part, the 17-3112 MOU reads:

> The MOU Parties agree that Exhibit 2, attached hereto, confirms definitionally clear standards for documentation that is necessary and appropriate for GMP to provide in future traditional cost-of-service rate cases to satisfy the known and measurable requirements for GMP's capital projects or programs. The documentation standards contained in Exhibit 2 shall remain in full force and effect for future GMP traditional cost-of-service rate cases unless or until they are modified by the Commission or by express agreement between the Department and GMP. The MOU Parties further agree that the documentation standards outlined in Exhibit 2 shall also apply in any future alternative or non-traditional rate cases from GMP unless or until a separate documentation standard is established by the Commission or by express agreement between the Department regarding documentation in such cases.[7]

While the 17-3112 MOU required GMP to develop certain documentation, the Department retained the right to raise issues with the adequacy of Project Verification Documents as part of a challenge to any specific GMP capital project or program and to raise issues with the prudency of a project.[8]

Q15. In your opinion is the supporting documentation used for cost estimates sufficient to arrive at a known and measurable value of the capital projects proposed by GMP?

A15. In some cases, the documentation is adequate; in other cases the documentation is insufficient. The MOU required GMP to provide:

> A project cost summary providing an itemization of the cost elements of the project, including supporting documentation

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[7] 17-3112 MOU, ¶26, page 7.
[8] *Id.,* ¶28.

(vendor quotes, resource estimates based on similar projects, etc.);[9]

The cost estimating technique used by GMP is reasonably transparent to show how the costs were built up, but the cost estimating is simplistic in terms of electric utility costing methodologies. I have identified errors in some project cost estimates which I will discuss later.

The adjustments to the projects that I recommend throughout my testimony are required to more accurately reflect the known and measurable costs for consideration to be included in rate base.

Q16. Can you provide examples of the errors that you observed in the project documentation?

A16. Yes. When constructing a power line along a roadway, it is a safety requirement to have flaggers on site to direct traffic for the safety of the motorist as well as for the construction crew. GMP's documentation includes two flaggers hired from a third party at a fixed hourly rate. However, GMP has estimated more hours for the two-man flagging crew than the total hours needed for construction. I have documented specific projects where this has occurred and will address each one later in my testimony.

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[9] 17-3112 MOU, Exhibit 2, page 2 of 3.

Q17. In your opinion can the qualitative and/or quantitative benefits for individual projects by GMP be improved? If so, how?

A17. Yes, I believe there are better metrics available to help GMP prioritize reliability projects. Currently, GMP provides information regarding the cost savings to GMP by tracking the manhours of GMP employees and the associated cost to restore outages on a particular line section before and after the upgrade to the line section. Below is a representative quantitative cost analysis which is provided in Project 130658 Hartland Line 9 & 901;

> The benefits of this project were calculated using our 4-year outage history for this specific line. Two line workers are assumed per event, and we assumed 35.5 crew hours. Take the crew time per hour at the time-and-a-half rate of 64.90/per employee = $4,607.72 labor savings for the events. [10]

The scale of these savings is minor compared to $411,214 for the cost of the system upgrade to the Hartland lines.

In my opinion, a better method to consider reliability benefits is from the customer's perspective. What is the value to the customer to not experience an outage? For commercial customers, value can be lost sales and loss of production. Some commercial processes require extensive re-start time. Many retail businesses must re-boot computer systems and security systems. Even residential customers have provided, via surveys, their opinions of the value of an outage. The Lawrence

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[10] See 130658 Hartland line 9 & 0-1 – Financial Analysis.docx filed as part of the rate case workpapers.

Berkeley National Laboratory developed the *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.*[11] The econometric models from this report were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com) which is an online tool designed for electric reliability planners at utilities, governmental organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements.[12]

The ICE calculator will calculate cost savings from the customer's perspective for reliability improvement projects. Typically, the benefits of an overhead improvement may extend for twenty years into the future whereas the benefits of an undergrounding option may extend for 30 years or 40 years into the future. The reliability models allow the user to compare the net present worth value of reliability improvements over a span of many years.

I ran an ICE model for the Hartland Line 9 & 901 project using historical data provided by GMP and an assumption as to the reliability improvement for the affected residential customers. I used default values for inflation and interest for present worth value calculations and I assumed an improvement period of 20 years.

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[11] Exhibit PSD-KJM-2, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Lawrence Berkeley National Laboratory, January 2015.

[12] Exhibit PSD-KJM-2, Executive Summary, page xi.

The result of the model is that the twenty-year savings is $118,116. This value would have been greater had there been any commercial customers on the affected line section.[13]

I am sharing this information for consideration when comparing reliability options and to help in prioritizing reliability projects. For example, the animal guards being installed in various substations will affect many customers and therefore the ICE calculator will likely show significant benefits for these devices. Unfortunately, there is insufficient data in the record for me to make such a model but this data should be readily available to GMP.

Therefore, I recommend GMP consider using the ICE Calculator tool in the analysis and prioritization of future reliability projects.

Q18. What are your thoughts regarding the use of animal guards in substations?

A18. The use of animal guards in substations can reduce system outages and protect equipment from flashovers during a fault. GMP is proposing to install animal guards on jumpers and exposed bus work in five substations. These substations include Dorset Street, Town Line, Iroquois, Ethan Allen and Mallets Bay. The total cost to purchase and install these plastic covers on jumpers and bus work is $459,852. GMP

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[13] Exhibit PSD-KJM-3, ICE Calculator report for the Hartland Line 9 & 901 project.

has over 185 electric substations.[14] The justification for these devices was only four (4) outages on the transmission system in Chittenden County in the last two years.[15]

While I generally agree that the use of insulators on jumpers and bus work will reduce animal caused outages in a substation, the cost of these mitigation devices cannot and should not be applied wholesale to all 185 substations. In fact, I noted that none of the new substations proposed by GMP includes insulating materials on the bus work or jumpers.

Q19. Please provide your comments regarding the animal fencing GMP is proposing in certain substations.

A19. The animal fences are essentially electric fences that prevent animals such as snakes, racoons, or other climbing animals from entering a substation. Snakes and raccoons often are drawn to substations by the presence of nesting birds and their eggs. This type of deterrent does not prevent outages caused by squirrels and birds. GMP has fifteen (15) substation slated to be equipped with these fences at a total cost of $452,071. This total excludes the costs of the fences proposed in Project 148607 South Poultney transformer replacement, and Project 143993 Barre South End

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14 Otley pf. at 4, line 9.

15 See Project 153799 – Mallets Bay Animal Mitigation.docx financial analysis filed as part of the rate case workpapers.

Rebuild. I note in the next two years that none of the new/upgrade stations include funding for animal fences.

The use of animal fences compared to animal guards is subjective and depends on the local environment. Also, animal fences cannot and should not be uniformly applied to all 185 substations.

GMP states in the project justification that the animal fences require no O&M and have a depreciated life of 40 years. I disagree with these assertions. This animal fence is no different than an electric fence used on farms. Further, there is a gate designed to allow personnel to safely access the substation without being shocked. These controls have a service life closer to 20 years than 40 years. Also, a major drawback to these animal fences is that the line personnel have to remember to turn on the fence when they leave the substation.

Q20. Are you recommending disallowing the animal guards or animal fences as proposed by GMP?

A20. No. However, but I think that it will be important for the Department and the Commission to track substation outages and the effectiveness of these types of deterrents to determine whether such costs will be appropriate in future rate cases. No one deterrent is 100% effective, but for the level of investment, customers deserve to see a measurable reduction in substation outages.

Q21. GMP has proposed several major substation projects, do you have an opinion regarding the known and measurable costs for these projects?

A21. GMP has proposed seven projects that I deem to be major substation rebuilds and/or upgrade projects. These projects are needed for reliability and power quality. GMP's method for estimating the cost of building a substation uses contractor bids for different component parts and builds up a total project cost. However, for larger substation projects a single mobilization is used for construction of the project. There are economies of scale when a single contractor performs multiple tasks, which can facilitate a competitive bid price for a large project. The table below shows the major substation projects with actual costs and forecasted costs. Note that all of these projects are forecasted to be completed by December 2018. On page 8 of his prefiled testimony, Mr. Fiske stated two months were added to the completion of major projects to insure the projects would be completed in the time allotted. Thus, a project projected to be completed in December will likely be completed by the end of October.

Major Substation Projects	Actuals To-Date: Thru Dec 2017	Forecast: Jan 2018 - Dec 2018	Total
143591: South Brattleboro RBLD	2,335,931	290,041	2,625,972
143593: Barre South End	42,042	2,732,058	2,774,100
143595: Barre North End	1,826,685	389,742	2,216,427
148596: Sharron Sub - GMP Portion	320,359	34,101	354,460
148607: South Poultney Xfmr/Fence	250,384	290,078	540,462
148622: East Jamacia Bkr/Rly/RTU/Sec	147,766	386,956	534,722
152949: Sand Road 34kV Regulators	759	436,858	437,617
	4,923,925	4,559,833	9,483,759

Rather than relying on forecasted values for these substation projects, it may be beneficial for the Commission if GMP files updated actual costs through June 2018 (or later date if available) as this case proceeds. I understand that Vermont law has a prohibition on updating in pending rate cases, but based on the proposed schedules for these projects, a significant portion of the actual costs should be known by now. The actual costs should not be permitted to exceed the forecasted values provided by GMP, but seeing the actual data will provide better clarity on the accuracy of the cost estimates and any underlying contingencies.

Q22. Are you recommending any disallowance of transmission line projects?

A22. Yes. GMP has recommended eight projects that include installation of motor operated air break (MOAB) switches on 35kV and 46kV transmission lines which total $2,494,511. These MOAB switches are connected to SCADA which allows for remote operation of the switches. However, to be clear, these switches do not reduce the frequency of outages. Rather, the remote operation helps to reduce the duration of an outage. Most of the projects have existing gang operated air break (GOAB) switches in place that require manual operation but serve the same purpose as the MOAB switches.

The justifications for these projects do not identify past reliability/outage problems that these MOAB switches relieve.

Project 159729- MOAB Newberry and Project 159730 - MOAB Castleton are projected to be complete in 2019. Project 135206 Riverside MOAB, Project 153590 – MOAB Thetford, and Project 153593 – MOAB Jeffersonville are scheduled for completion in 2018. I recommend all these projects be deferred until the next rate period which are summarized in my Exhibit PSD-KJM-4. The reason for the deferment is to balance the increase in reliability spending across several years

Q23. Do you recommend an adjustment on project 126847 RTE 7 Brandon URD?

A23. Yes. The Town of Brandon and the Vermont Agency of Transportation ("AOT") initiated a project to upgrade and beautify Main Street Brandon. This is per the regulatory request of the Town of Brandon and AOT. The request was made to all utilities, including GMP, to relocate their existing facilities along Main Street to underground facilities. An agreement was signed between the Town of Brandon and GMP that stipulated that Brandon would reimburse GMP $203,176 for the differential cost of overhead facilities and Brandon's preference for GMP to underground the electric facilities.[16] This credit to the project is not included in GMP's Exhibit 2 which documents the cost of the project. Also, I noted that in 2016, GMP's estimate to Brandon for the cost of the underground project was $261,875. Now, in just two years, the cost of the project has escalated to $409,051. This error in the original

[16] Exhibit PSD-KJM-6, Utility Relocation Agreement between the Town of Brandon and GMP, Project Number NH 019-3(496), November 19, 2016.

estimate forces the electric consumers to absorb the cost difference between $409,051 and $203,176 to the sole benefit of Brandon.

Exhibit PSD-KJM-5 of my testimony provides for a downward adjustment to this project of $203,176.

Q24. In your opinion are the costs associated with project 141211 Coolidge State Park a justified project?

A24. No. GMP proposes to re-build a single-phase distribution line that provides service to six customers at a cost of $509,837. GMP failed to provide adequate alternate plans for this project. The project calls for replacing all the poles in their current locations because GMP's request to relocate to the roadside was denied by the Vermont Department of Forests, Parks and Recreation. Further, GMP proposes to replace all of the conductor on the line because of the presence of splices.

The investment for this line for the benefit of only six customers is not justified. From the documentation that I reviewed, it appears that GMP failed to adequately consider undergrounding this single-phase line. Because this line is basically in the woods with no other utilities the trenching cost would be below average, no tree trimming required, and no ledge sets for poles. Using GMP's Labor Detail spreadsheet, my estimate for single phase underground through the woods is less than $200,000.

GMP does state that solar and battery resources will be used for a portion of the service at the state park. Although, I am not aware of any capital project for the inclusion of these facilities in GMP's rate base. GMP should have provided a full analysis of a battery system or microgrid for the customers served by the line coupled with a less costly distribution system upgrade.

GMP has failed to provide a thorough alternate plan for this project as required per the MOU. Without such a thorough analysis that truly considers alternatives, this project is not justified and should not be included in rate base.

Q25. In your opinion is project 141961 Spear Street a justified project?

A25. No. This project proposes to construct a tie line between Circuit 32G7 and Circuit 78G2. The justification for this tie line is to reduce the number of outages. However, a tie line does not reduce outages. At best, a tie line provides an alternate feed to accelerate restoration of service to a limited number of customers affected by an outage. GMP notes that this area of the system averages only one outage per year and the average customer hours out of service is only 4,928 per year.[17] This indicates that power is restored quickly (in less than 90 minutes), or the outage affects less than 30 customers per year.

[17] GMP states 4 outage over a 4-year period and 19,713 customers hours for the four-year period. See 141961 Spear St 32G7 & 78G2 – Financial Analysis.docx filed as part of the rate case workpapers.

GMP infers that the project also helps by providing feeder back-up capabilities. Yet there have not been sufficient outages to justify the capital expenditure. A more reasonable and cost-effective course of action is to continue diligent maintenance of circuits 32G7 and 78G2, an option which was not addressed by GMP.

Without the required alternate plan analysis, this project should be excluded from the rate base.

Q26. Do you recommend an adjustment to project 146655 44G2 Williston?

A26. No. However, I did note that the layman's description of the project is incorrect. GMP states that the project would "Install approximately 15,000' of three-phase 477 spacer cable with approximately 5,000' 336 of bare neutral wire."[18] However, a review of the labor estimate and the actual material charged to the job makes it clear that the project actually installed 15,000 feet of 477 tree wire (single conductor, not three phase) and approximately 5,000 feet of 336 ACSR bare neutral wire. In general, a spacer cable can provide greater reliability and reduce O&M for right-of-way maintenance, so it is not clear if the justification has considered the use of tree wire rather than spacer cable.

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[18] See 146655 44G2 rebuild - Financial Analysis.docx filed as part of the rate case workpapers.

Q27. Can you describe the purpose of project 148867 Ottauquechee fiber?

A27. This project replaces poles to allow GMP to install a fiber communication line. The fiber line allows downline reclosers to communication with various "large electric generators (hydro, solar) operating and pushing electrons back on the GMP system."[19] GMP foresees that more generation will be added in this area. GMP describes this type of communication as a direct transfer trip ("DTT") used for preventing islanding of customer owned generators. Islanding creates a safety risk for the public and GMP's employees, and is not permitted by current industry standards.[20]

These costs should be disallowed from rate base. GMP's own interconnection guidelines specifically so that "the Company (GMP) will install, own and operate a Customer billable Direct Transfer Trip (DTT) scheme."[21] If GMP fails to bill or collect the necessary monies for the DDT scheme from current customer-owned generators in accordance with Commission approved guidelines,[22] that cost should not be borne by the rate payers. Further, if new generators are expected in the area as suggested by GMP, the cost of the DTT can be allocated in whole or in part to the next customer-owned generator that will increase the likelihood of islanding the circuit.

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[19] See 148867 Ottauquechee fiber – Financial Analysis.docx filed as part of the rate case workpapers.

[20] IEEE Standard 1547*, Standard for Interconnecting Distributed Resources with Electric Power Systems*, 2018 (Copyrighted material).

[21] Exhibit PSD-KJM-7, GMP *Distributed Resources Interconnection Guidelines*, October 22, 2015, page 4.

[22] Commission Rule 5.500 Interconnection Procedures for Proposed Electric Generation Resources, effective September 9, 2006.

Q28. Can you discuss the upgrades to the Pownal to Bennington tie?

A28. Yes. There are actually two projects; Project 149662 Tie Line L51 & L11 Bennington and Project 149663 Pownal Tie w Bennington. The combined budget of these two projects is $1,975,250.[23] These combined projects install 7,600 of new three phase line along the 28,000 foot route from Pownal to Bennington. The cost per mile for these combined projects is $1,372,654 which is more than GMP's reported cost for undergrounding this power line on a per mile basis.[24] The justification for the new tie line is the Pownal Substation is served on a radial transmission line and provides service to approximately 1,695 customers. There appears to be a non-radial transmission line just north of the Town of Pownal. Note that recent substation re-builds in the current rate base cost about $2,500,000. For the cost of these two projects, GMP could construct a loop-feed substation and eliminate the need for this tie, and reduce system losses. However, GMP did not consider this alternative nor did GMP adequately consider undergrounding which appears to have a lower cost per mile solution. Rather, GMP considered their standard list of four alternatives; hot spot tree trimming, battery storage, undergrounding, and reconductoring on existing poles. A loop-feed substation option would provide greater reliability, lower losses, and be able to support more solar. Based on the information presented by GMP in its support

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[23] See 149662 Bennington to Pownal – Financial Analysis.docx and 149663Pownal - Bennington tie – Financial Analysis.docx filed as part of the rate case workpapers.

[24] See 149663 Pownal Tie – Financial Analysis.docx filed as part of the rate case workpapers.

document, this proposed tie line project appears to be unnecessary and will resulted in unjustified expense for ratepayers.

Q29. Did you analyze the cost estimate for project 149662 tie line Bennington and project 149663 Pownal tie?

A29. Yes. Project 149663 called for 1,600 feet of three-phase 477 spacer cable[25] which would translate to 4,800 feet of wire. However, the wire charged to the project greatly exceeded 4,800 feet. The actual costs charged to the project were provided by GMP and showed a total cost of $62,917 for three-phase 477 spacer cable, which in other projects (Project 146574) the cost per foot is $2.33 yielding 27,000 feet of wire charge out to this project.[26] If this project is not excluded for lack of adequate alternative planning, then the cost of the project should be reduced by the cost of the excess wire.

In addition, I found that Project 149662 and Project 149663 both substantially over estimated the cost of flaggers.[27]

25 *Id.*
26 See 149663 Actual Expenditures.xls filed as part of the rate case workpapers.
27 Exhibit PDS-KJM-5, Distribution Lines – Large, Cost Reductions Summary.

Q30. Did you review project 150420 Hydville? If so, what are your conclusions regarding this project?

A30. Yes, I reviewed GMP's submitted details on this project which calls for 20,000 feet of 3-phase 477 spacer cable and 20,000 feet of 0052 aluminum messenger. This combination is not possible because there should be three feet of 477 space cable for each foot of 0052 aluminum messenger, so it is not clear if this represents 20,000 feet of pole line or only 6,666 feet of pole line.[28] It becomes even more confusing, because the material in the project estimate was 20,556 feet of 477 ACSR bare conductor with 9,800 feet of 4/0 AAAC neutral which is listed as "inactive fall 2013".[29] Yet the project calls for the telephone company to install/replace 60 poles for this project. Typically, 60 poles would support 9,000 to 12,000 feet of line. GMP's documents also indicate this project will have 6,832 feet of 477 bare conductor.[30]

The primary justification for the project is to improve reliability on an older single-phase line (40 years). Yet, GMP says there has been only one outage on this line in four years. Therefore, improving reliability is not a reasonable justification for rebuilding this line. The secondary purpose is to improve the capability to use this circuit as a feeder backup and additional capacity[31] to the Castleton area. GMP is

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[28] Pole line footage is defined as the distance between poles regardless of the number of conductors on the pole.

[29] See 150420 Hydville Line 4 Exhibit 2.xlsx filed as part of the rate case workpapers.

[30] GMP's Response to PSD Discovery Request DPS1.Q42 attachment GMP.DPS1.Q42.4 - 2019 Capital Planning Document 2 16 2018.xls.

[31] See 150420 L4 Hydville – Financial Analysis.docx filed as part of the rate case workpapers.

singularly focused on installing larger wire when alternately, it could install single phase tree wire at a tenth of the cost which would have moved the line to road and reduced outages. Further, GMP provided no information regarding the need for backup capacity in the Castleton area.

This project is not a necessary investment to mitigate a single outage in four years. Further, the backup capacity is not justified in terms of load growth, radial feeds, and reliability problems in the Castleton area that necessitate this backup feeder.

Q31. Did you review project 153711 Stonehedge Rehab? If so, what are your conclusions regarding this project?

A31. Yes, I reviewed this project that calls for the replacement of older underground single-phase cables. Much of this project is complete. However, GMP is estimating 500 hours for flaggers in 2018 when there are only 159 hours of line worker time remaining on the project. Overhead distribution line construction crews are typically four man crews therefore, only 39.75 hours of flagging are required.[32] I recommend an adjustment which reduces the cost of flagging along with associated overheads by $33,820 as shown in my Exhibit PSD-KJM-5.

[32] See 153711 Stonehedge Rehab Exhibit 2.xlsx filed as part of the rate case workpapers.

Q32. Did you review project 153588 line 74 section I and project 153950 line 74 section II? If so, what are your conclusions regarding these projections.

A32. Yes, I did review these two projects which budgeted $1,601,945 to rebuild Line 74. Project 153588 includes using 336 tree wire on a single phase line. A more appropriate design would be to use 1/0 tree wire on a single-phase line. A single-phase line should carry no more than 50 to 70 amps, and a 1/0 single-phase line is rated for over 200 amps. Using 336 tree wire adds to the cost with no benefit to the rate payers. I am recommending a cost reduction for this project of $13,871. Reference my Exhibit PSD-KJM-5 for details.

Regarding Project 153950, GMP has already incurred $69,629 in contractor costs through December 2017 and an additional $130.087 in other costs associated with the project. GMP has obtained a bid price from 3Phase Line Construction for a lump sum price of $589,511 for work in 2018 which includes all labor for installation of poles, anchors, and conductors specified for this project.[33] In addition, GMP estimated another $85,864 for Large Tree Trimming. This total cost remaining on the project $675,375 in contract labor plus $31,822 in material stock which is need to install 20,000 feet of single phase tree wire with poles.

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33 See Ele_18_08_153950.pdf filed as part of the rate case workpapers.

I notice that Project 153588 Line 74 Section I has 16,000 feet of single phase tree wire but the poles are set by the telephone company. GMP's estimated cost for this project is $419,960. Once all GMP's overheads are included in Project 153950 Line 74 Section II, GMP's cost escalates to $1,181,985. The only real difference between Section I and Section II is 62 poles to be installed by GMP in Section II. I recommend the cost for Section II be adjusted lower by $306,894 to the Lump Sum Bid provided by 3Phase Line Construction and including other sub-contractors, design, and material costs to a final cost of $875,091. Reference my Exhibit PSD-KJM-5 for this adjustment.

Q33. Did you review project 155051 Newfane line 6 to line 3? If so, what are your conclusions regarding this project?

A33. Yes, I reviewed this project that calls for the installation of 11,500 feet of 447 spacer cable. GMP is estimating 1,000 hours for flaggers in 2019 when there are only 1,956 hours of line worker time estimated on the project. Most construction crews are four-man crews so only 489 hours of flagging are required.[34] I recommend an adjustment to reduce the cost of flagging along with associated overheads by $35,477 as shown in my Exhibit PSD-KJM-5.

[34] See 155051 Newfane Line 6 to Line 3 Exhibit 2.xlsx filed as part of the rate case workpapers.

Q34. Did you review project 155199 Bethel 28 circuit upgrade? If so, what are your conclusions regarding this project?

A34. Yes, I reviewed this project that calls for the installation of 14,000 feet of 447 spacer cable. GMP is estimating 4,000 hours for flaggers in 2019 when there are only 1,930 hours of line worker time on the project. Most construction crews are four man crews so only 482.5 hours of flagging are required.[35] I recommend an adjustment to reduce the cost of flagging with associated overheads by $244,206 as shown in my Exhibit PSD-KJM-5.

Q35. Did you review project 157361 Westminster RTE 5 - Hendrix? If so, what are your conclusions regarding this project?

A35. Gratton Line Construction provided a labor quote on this project of $438,201[36] for the installation of 5,270 feet of 3-phase 477 spacer cable. GMP included flagging cost for the project, but GMP's contractors are required to provide their own flagging. Therefore I recommended reducing the cost of this project by $16,149 as shown in my Exhibit PSD-KJM-5.

Also, GMP adds 21% to a contractor's price for distribution line work. Thus, this construction project totals $788,615 when the labor and material portion of the work is only $522,969. Excessive adders make it difficult to determine known and measurable

[35] See 155159 Bethel 28Cir Line 5. Exhibit 2.xlsx filed as part of the rate case workpapers.
[36] See Ele_18_09_15736.pdf filed as part of the rate case workpapers.

cost for comparisons. The cost per mile for 477 spacer cable averages roughly $375,000 per mile, but this project, with no obvious irregularities, is closer to $795,000 per mile. Undergrounding this circuit at $1,310,274 per mile would be nearly as cost effective with superior long-term reliability.

Q36. Did you review project 158518 Sheldon line 9 – phase 1? If so, what are your conclusions regarding this project?

A36. Yes, I reviewed this project that calls for the installation of 7,000 feet of 3-phase 447 space cable and 3,000 feet of 3-phase 477 bare conductor. GMP is estimating 1,800 hours for flaggers in 2018 when there are only 2,076 hours of line worker time on the project. Most crews are four man crews so only 519 hours of flagging are required.[37] I recommend an adjustment reducing the cost of flagging along with associated overheads by $94,032 as shown in my Exhibit PSD-KJM-5.

Q37. Did you review project 159358 Barre Conv 37CIR? If so, what are your conclusions regarding this project?

A37. Yes, I reviewed this project; the first in a series of projects to convert the operating voltage at Barre. GMP is estimating 2,296 hours for flaggers in 2019 when there are 5,955 hours of line worker time on the project. Most crews are four man crews so only 1489 hours of flagging are required.[38] I recommend an adjustment reducing the

[37] See 158518 Sheldon Line 9 – Phase Exhibit 2.xlsx filed as part of the rate case workpapers.
[38] See 159358 Barre Conv – 37Cir – Phase Exhibit 2.xlsx filed as part of the rate case workpapers.

cost of flagging along with associated overheads by $56,045 as shown in my Exhibit PSD-KJM-5.

Q38. Is the documentation of actual costs using quotes from vendors adequate to establish known and measurable costs?

A38. No. There are significant problems in GMP's costing model that are not supported by the vendor quotes. Below is a table that compares the vendor quotes to GMP's labor model for distribution projects.

Description	Vendor Quote	Units	GMP Model	Units
Set wood pole - union labor	$ 1,536.00	each	$ 600.38	each
Set wood pole - non-union labor	$ 918.00	each	$ 600.38	each
Install 3Ph Hendrix	$ 29.45	per ft	$ 11.16	per ft

The table shows that the vendor quotes and GMP's costing model are not comparable. Also, GMP provides quotes from construction contractors for three projects. Rather than demonstrate that GMP's labor cost spreadsheet is accurate, GMP simply used the contractor quote in the overall cost estimate. These contractor quotes represented in the range of 40% to 70% of the total project costs, and therefore do not provide greater certainty that the cost estimates of the projects meet the standard of known and measurable.

It would have been better if GMP had used their labor cost estimating spreadsheet to estimate a project and used construction contractor quotes to benchmark GMP's cost estimating methods. As it currently stands, stakeholders are left to *assume* the costs are reasonable because GMP developed a cost estimate which is unsubstantiated and not benchmarked from actual closed out projects.

I recommend that in future filings, GMP provide benchmarking of their estimating program with estimates to actuals and estimates compared to contractor pricing.

Q39. GMP has included blanket work orders for inclusion in the rate base. Can you please describe what these blanket work orders represent?

A39. Yes. Blankets are work order categories that have variable in-service dates and are typically closed monthly or quarterly.[39] Blankets are used to capture construction costs completed during the interim period and the rate affected period. I understand that the Department raised concerns about blankets in last year's GMP rate case, and the 17-3112 MOU calls for any single planned capital project within a blanket work order that exceeds $250,000 to have project-specific documentation.

However, in my opinion, expenditures in blanket work orders are not known and measurable costs. The Commission standard for known and measurable is "changes that are measurable with a reasonable degree of accuracy and have a high probability of being in effect in the adjusted test year."[40] Mr. Fiske describes blankets "as categories of spending where the anticipated level and need for spending is known

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[39] Fiske pf. at 8, lines 9–10.
[40] Case No. 17-3112-INV, Order of 12/21/17, at 12.

based on historical experience, but the exact location of work or individual project that will be required cannot always be known in advance."[41] GMP stated that distribution equipment purchase blankets are to install new or to replace failed or deteriorated equipment to maintain system capability and reliability.[42]

According to Mr. Fiske the work location is not known and therefore, by extension, the cost is unknown. For failed equipment, the location is not known in advance and the repair cost is also unknown. These are the exact opposite of known and measurable. The projects are of unknown locations and unknown size or complexity. The total cost is estimated based on historical values, but the historical values have large variations in annual cost. What I mean is that the changes in cost are not just an inflation increase, but rather are differences of 150% or more per year.[43] Further, GMP used both their own UI Tool for estimating the blanket costs and the 5-year average of the blanket cost category and selected the lessor of the two methods. GMP's estimate was significantly different than the 5-year average which demonstrates the uncertainty in the costs to be incurred each year. Allowing blanket work orders in the rate base eliminates any incentive for the utility to be efficient in design and construction. Rather all projects become cost-plus in nature which, in turn, will increase the net cost of these blankets over time.

41 Fiske pf. at 19, lines 12–15.
42 Exhibit PSD-KJM-8, GMP's Response to PSD Discovery Request DSP1.Q44.
43 See Blanket .xlsx (Meters) filed as part of the rate case workpapers.

In my opinion, the capital expense of blanket work orders should be excluded from rate base because of the inability to satisfy the unknown and measurable requirement. An average of historical costs does meet not this burden. Excluding these expenditures from the rate base, simply means that these expenditures will be added to plant in service at the time of the next rate case. The timing of the next rate case is controlled by the utility. This treatment would be no different than the treatment of a large project, such as generation plant, that which would not be complete within the effective rate period. However, it would be possible to accept actual closed work orders through the second quarter of 2018 assuming the closed amounts do not exceed the budgetary levels provided in the original filing.

Q40. Do you recommend that all dollars in blanket work orders be excluded from rate base?

A40. No. GMP's current rate case is different from prior years in that GMP is basing the rate period revenue off a forecast for anticipated loads, which includes new revenue associated with new customers. Therefore, the cost of new equipment forecasted to serve new customers should be included in a forecasted rate base. A forecasted year of revenue needs to be matched with the capital necessary to connect those new customers. The costs for connecting new consumers can be demonstrated with average historical costs for a set of diverse consumer types (residential, commercial, etc.).

However, maintenance items, undefined material replacements, capital equipment for storm restoration, relocation of lines, etc., should be excluded from rate base treatment for the rate period.

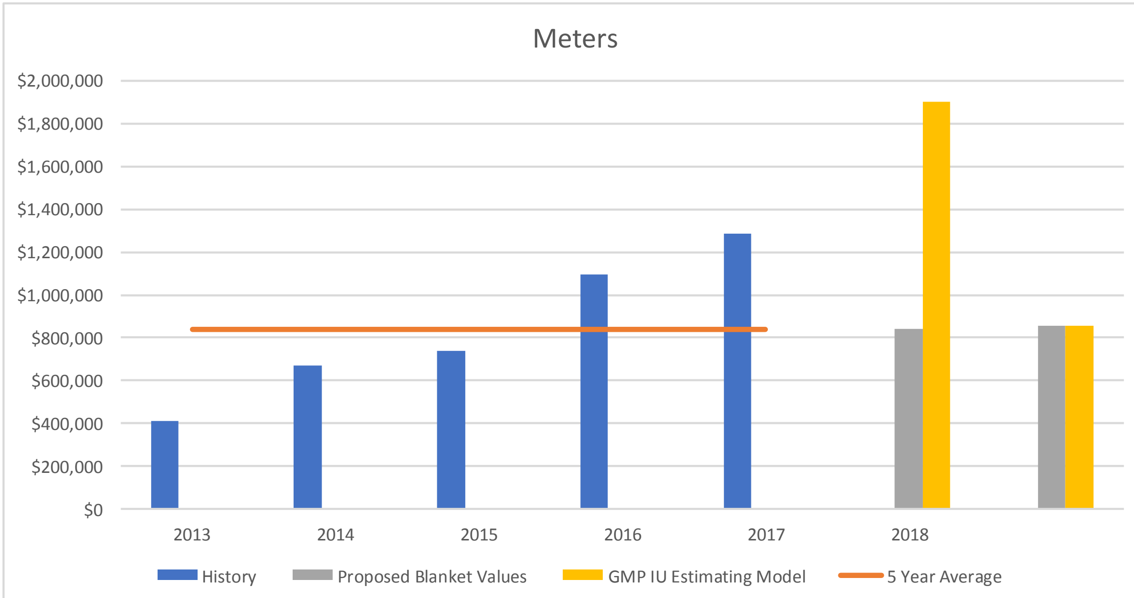
Q41. Can you provide analysis of the blanket work orders for metering?

A41. Yes. The GMP work order budget for meters is summarized in the following table

	Oct 2017 to Sep 2018	Nov 2018 to Sept 2019
Meter $$	$ 861,346	$ 835,066

Mr. Fiske testified that GMP used the Handy-Whitman indices for the inflation factors when developing the budgets for the blankets. The workpapers for meter blankets show a single CPI value for all blankets and not a Handy-Whitman index value for the differing FERC accounts. For example, the Blanket for Meters used a five-year average inflation value of 1.30%, while the Handy-Whitman value is only 0.9% for electric meters. This difference in the inflation factors yields a reduction of $21,181 in the meter budget for 2018.

The following graph is the 5-year history of expenditures for electric meters in 2018 dollars as provided in GMP's work paper for blankets on meters.



The 2017 meter cost was $1,288,270 (2018 dollars) while the 2014 meter cost was $686,839 (2018 dollars). The five-year average in 2018 dollars is $861,346. In just three years the meter costs have nearly doubled. The increase must be viewed in light of the fact that GMP replaced its meters with AMI meters in 2012 and 2013. Thus, GMP has a fleet of new meters which should have a low failure rate early in the service cycle. AMI meters have a service life of 15 years, but this is due to obsolescence of the software and not due to failure of the hardware of the meter itself. Thus, in my opinion, for new meters, a failure rate of 0.5% or less of the total number of meters per year is expected. Assuming GMP has roughly 230,000 meters, that would imply a replacement level of 1,150 electric meters. In addition, this budget would include meters for new services. The projections of additional customers is about 991 new customers per year.[44] The growth rate of new customers is about 0.37% per year. Because this growth rate is consistent, the annual expenditures for new meters should also be consistent, especially when viewing the costs in constant 2018 dollars.

GMP used its UI Tool to estimate the 2018 expenditures for meters and concluded the total cost would be $1,901,149. This value is shown on the previous Graph and reflects the continued uncontrolled increase in meter costs. Then in the following year (2019) GMP's UI Tool estimate for meter costs is $835,063 which is less than the five-year average.

That is a change in predicted expenditures for meters of more than $1.1 Million or 227%. How can a rate payer have any confidence in the validity of GMP's estimates for a category of capital spending that should reflect no growth or changes because the system is brand new and the addition of consumers is consistent from year to year?

I believe it would be appropriate for all meter costs as presented by GMP to be disallowed from rate base. In addition, if GMP can clearly demonstrate the cost of meters for new customers to be added in the rate effected period, then those meters should be included. Reference my Exhibit PSD-KJM-9.

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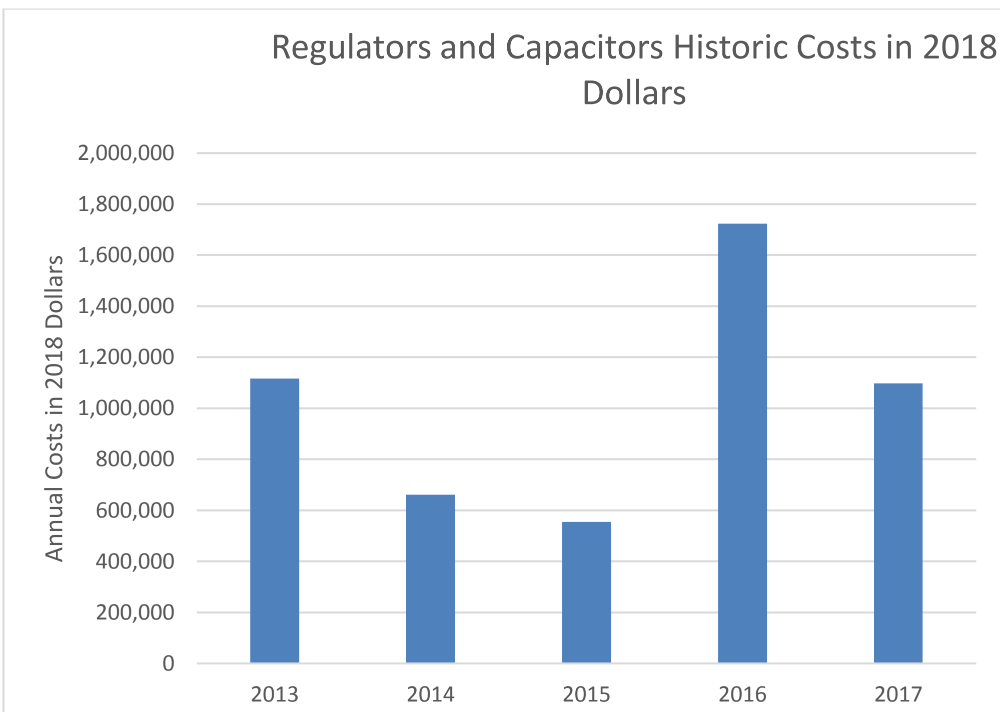
44 See GMP 2019 Budget Forecast Report GMP-ER-14 Table 2 and Table 5. filed as part of the rate case workpapers.

Q42. Do you recommend any changes to the blanket work orders for regulators and capacitors?

A42. Yes. The 2018 and 2019 blanket work orders for regulators and capacitors is based on a 5-year average of capital spending.[45] However, the historical costs for regulators and capacitors have been very erratic as shown in the following graph.[46] Further, GMP has more than doubled the spending on these components in 2016 and 2017. This increase in 2016 and 2017 drives up the five-year average.



45 See FY2018 Regulators and Capacitors.docx Financial Analysis filed as part of the rate case workpapers.
46 See Blanket.xlsx (Regulators – 2018)) filed as part of the rate case workpapers.

The future expenditures related to regulators and capacitors are not known and measurable costs. These costs are for replacement of aged equipment and in some cases to maintain adequate voltage on the system. The adequacy of voltage, or specifically response to changes in voltage that require regulators or capacitors are due to load increases on the distribution system. However, GMP load forecasts show a decrease in energy sales, thus the need for additional regulators and capacitors is very limited.

Since the costs for this blanket work order are not known and therefore cannot be measured, I believe it would be appropriate to disallow the 2018 and 2019 work orders related to regulators and capacitors with a total cost of $1,696,412 from the rate base for this case. Reference my Exhibit PSD-KJM-9.

Q43. Do you recommend any changes to the transformer blanket work orders for 2018 and 2019?

A43. Yes. The financial analysis for the distribution transformers noted that these blanket work orders included new services, replacement of aged equipment, and transformers needed as part of voltage conversion projects.[47] A voltage conversion project occurs when the utility converts the operating voltage from 4kV to 12.5 kV as is the case with Project 159358 Barre Conv 37. This particular project includes the replacement of

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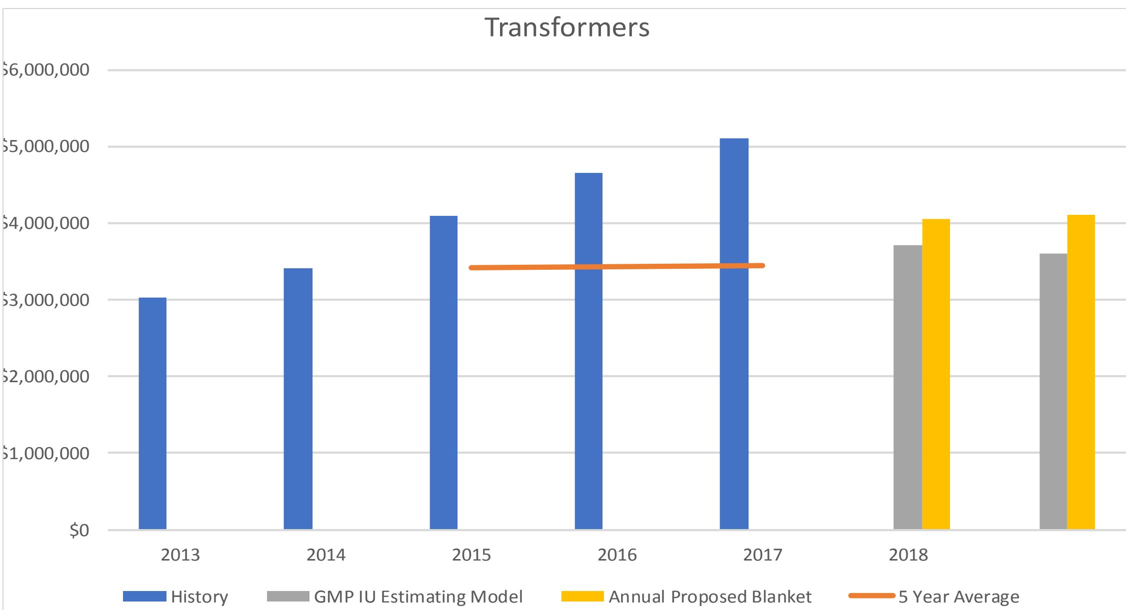
[47] See FY2018 Distribution Transformers.docx financial analysis filed as part of the rate case workpapers.

175 distribution transformers.[48] The transformers are not accounted for in the distribution projects but rather charged to a special transformer account. Therefore, the blanket work orders for distribution transformers would have to include the transformers needed for this conversion project at Barre.

The following graph is the five-year history of expenditures for distribution transformers in 2018 dollars as provided in the GMP work paper for blankets on transformers.



GMP added nearly $1.7 Million in capital to the annual transformer expenditures from 2014 to 2017. The need for this increase is not clear and appears arbitrarily added to

48 See 159358 Barre Conv 37 – Financial Analysis.docx filed as part of the rate case workpapers.

the five-year average similarly to the increases in the meter and regulator/capacitor blankets. GMP used its UI Tool to estimate the cost of new transformers and concluded the annual cost of transformers going forward would be $1.4M less than the amount spent in 2017. Looking at the numbers differently, the UI tool estimate is 27% below the prior year estimate. These large swings in annual budgets erode confidence in the necessity for the dollar amounts provided by GMP.

These wide variances in costs for such a simple component as a transformer confirms my belief that these costs are not known and measurable.

As I stated earlier, distribution transformers that should be included in rate base for the rate effected period are transformers for the projected 991 new consumers per year and transformers for voltage conversion projects. GMP has not provided documentation for new transformers or for transformers associated with voltage conversion. Therefore, I think it would be reasonable that no costs for transformers be included in the rate base until such time as GMP can demonstrate costs. See my Exhibit PSD-KJM-9.

Q44. Do you recommend any changes to the distribution line blanket work orders for 2018 and 2019?

A44. Yes. The Distribution Line Category is all distribution line projects. GMP plans to spend $34,558,320 in the interim rate period and $20,167,952 in the rate period for the

Distribution Line category.[49] Pursuant to the 17-3112 MOU between GMP and the Department, GMP has provided project documentation for each distribution line project with an estimated cost greater than $250,000 in the Distribution Line – Large Category. This change will affect the historical cost of the blanket amount for the Distribution Line category.

GMP workpapers show that all Distribution Line projects including "larger" individual projects were tracked as a group with three separate categories as shown in the following table.[50]

HISTORY FROM SUMMARY OF CONSTRUCTIONS		
Budget Group	**Actual $ 2017**	**%**
Distribution Lines Large Cap	13,441,489	41.91%
Distribution Lines Line Ext	3,450,727	10.76%
Distribution Lines Small Cap	15,179,784	47.33%
Dist Small Cap/Line Ext Total Percentage		58.09%
TOTAL DIST LINES	32,072,000	

To determine the Blanket for the Distribution Lines, GMP projected all Distribution Line costs (Large, Line Ext, and Small Cap.) using a five-year average of actual costs. Then GMP used the ratio of Distribution Lines Line Ext and Distribution Lines Small Cap (58.09%) to the total as the proxy to determine the blanket for Distribution Lines.

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49 Fiske pf. at 22, lines 12–14.
50 See Blanket.Final .xlsm (Distribution Lines 2018) filed as part of the rate case workpapers.

Because of the 17-3112 MOU agreement, in 2018 the Distribution Lines Large Cap will increase, and the Distribution Lines Small Cap will decrease due to the movement of projects larger than $250,000 from one category to the other. Therefore, this ratio would not be applicable.

Further, GMP should include in rate base the Distribution Lines – Line Ext which is the category used to capitalize the cost of new services to new electric customers. The average cost per customer assuming 991 new customers is $3,482 per customer which is a reasonable value to determine known and measurable costs for 2018 and 2019. A better method may be to use a five-year average of the cost per customer.

The Distribution Line – Large category is site specific with detailed cost estimates and justifications which I have previously addressed.

The remaining category is Distribution Lines Small Cap which are projects that GMP has no control of as to timing, size, or complexity in terms of cost. These costs are not known and measurable and could appropriately be excluded from rate base.

Q45. Do you recommend any changes to the substation and transmission blanket work orders for 2018 and 2019?

A45. Yes. The blanket work orders for substation and transmission equipment covers replacement of components such as lighting arresters, batteries, poles, insulators, etc.

These are future replacements that are done on an unplanned basis or replacements that are presently undefined. Clearly, this future work is not used and useful to provide electric service to customers.

From 2013 to 2014 the change in spending on transmission and substation blankets increased 128%, then decreased by 58% the next year and increased again 180% and increased 108% in 2015. Now GMP proposes a decrease of 83%. These are very large swings in the annual budgets, yet GMP expects that the five-year average is a known and measurable cost. Clearly, these future costs are not known and measurable because the replacement components are currently unknown and therefore the cost, by definition, is unknown. I believe that these costs could also appropriately be eliminated from the rate base.

Q46. Historically has the Vermont Commission permitted the use of blanket work orders in rate base?

A46. Based on conversations with Department staff, it is my understanding that these types of blanket work orders have historically been allowed by the Commission in past rate cases as known and measurable costs, but that the Department has raised concerns about continued growth of and overreliance on blankets and documentation in support of the blankets. This is expected because GMP cannot exactly define the expenditures, nor can it define or control when the construction will be completed. GMP admits that it cannot dictate the timing of many of these types of projects.[51] GMP can only guess as to the actual costs with a level of uncertainty.

Q47. Have you had discussed the implications of the 17-3112 MOU on GMP's 2018 blankets with the Department?

A47. Yes. In my discussion with the Department, we considered the application of the 17-3112 MOU to the 2018 interim period. The 17-3112 MOU was used, in part, to settle issues between the Department and GMP in the 2018 Rate Case, including significant reductions in the blanket work orders including the rate affected period which was 2018. Therefore, in accordance with the 17-3112 MOU, I believe it is appropriate to include the blankets as agreed to in Case No. 17-3112 for interim rate period in this case, which is 2018.

Q48. Does a submission of a blanket work order automatically mean that all costs should be included the current rate case?

A48. No. Simply completing a form used by GMP that follows the guidelines of Exhibit 2 to the 17-3112 MOU does not mean automatic acceptance of the blanket costs. In fact, the 17-3112 MOU does not specifically address blanket work orders, but rather only provides specific filing requirements for "major" and "non-major" projects.

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[51] Fiske pf. at 19, line 21.

Q49. Has the Department requested you to consider inclusive of some of the blanket costs?

A49. Yes. I was directed by the Department to take into account the Commission's historical acceptance of blankets and determine costs within the blanket budgets would be appropriate for inclusion in the rate base.

Q50. Please describe the parameters you set for determining inclusion in the rate base?

A50. As I stated earlier, GMP's current rate case is different from prior years in that GMP is basing the rate period revenue off a forecast for anticipated loads, which includes new revenue associated with new customers. Therefore, the cost of new equipment forecasted to serve new customers should be included in a forecasted rate base. This would include new meters, new transformers, new distribution lie extensions, new capacitors to correct power factor for the additional load, and new voltage regulators for the increase load of the new consumers.

In addition, replacement of failed equipment should be included in the rate base. These system components are necessary to maintain service through the rate period. Pole replacements for poles identified as needing replacement would be within my definition of failed equipment. Poles are identified for replacement when the structure no longer meets the requirements for strength as defined by the National Electric Safety Code Rule 261 and therefore have "failed".

GMP is required to do upgrades and relocate joint facilities in order to accommodate joint-use parties on GMP's pole as part of the third-party attachment tariff, and joint-use and joint-ownership agreements that currently exist with the telecommunication companies operating in the state. This this work is required by tariff, in my opinion, it should be included in rate base.

Q51. Please describe the parameters you set for determining exclusion in the rate base?

A51. In my opinion, items to be excluded are projects that GMP plans such as reliability upgrades, relocation of lines to the road, preparing structures for distribution automation, etc. as opposed to reacting due to failed equipment. These projects could be uniquely identified and included in the Distribution Line – Large category. I recognize these projects may not exceed $250,000 as provided in the current 17-3112 MOU, but because rate payers have to pay for these upgrades, it is only proper than the upgrades be used or useful or have known and measurable costs.

Another category I recommend excluding is road relocation to accommodate state and municipal road projects. These relocations still need to be built, however, GMP solely choose to place its facilities in the public right-of-way and took a known risk of future relocation costs. These projects once used and useful can and should be added to the rate base. Further, my experience with these types of road relocation projects is that there uncertainty as to the timing of the project and therefore the likelihood the project will be completed in the rate period.

Q52. Please provide the dollar amounts for the blankets that should be included in the rate base and how you determined those amounts.

A52. The Substation and Transmission blankets are described by Mr. Fiske to only include replacement of failed system components.[52] Therefore all of these costs should be included. Further my review of these costs indicates that the 5-year average would be a reasonable cost based on the data filed by GMP.

For the Metering Blanket, I recommend no change to the budgets proposed by GMP. I did an independent estimate for new meters and replacement of failed meters and found GMP's budget to be reasonable based on the parameters I established.

For the Transformer Blanket, I estimated the number of transformers needed for new services in 2019 including overhead and underground transformers. Based upon my estimate, GMP's budget for the 2019 Transformer Blanket needs to be reduced by $887,326 which is a 24% reduction GMP's proposed Transformer Blanket budget.

[52] Fiske pf. at 25, line 4.

For the Regulator and Capacitor Blanket, I budgeted for new units that may be needed for load growth of new consumers and budgeted for replacement of failed components in 2019. Based upon my estimate, GMP's budget for Regulators and Capacitor Blanket needs to be reduced by $338,605 which is a 16% reduction GMP's proposed Regulator and Capacitor budget.

For the Distribution Blanket. I used GMP's value for distribution line extensions to account for new consumers in 2019. I also developed a budget for pole replacements and a budget for joint-use facilities modifications for 2019. For the unit costs for pole replacements, I developed an average cost leveraging GMP's Labor Detail cost estimator which was included which of the Distribution Line – Large Projects. Based upon my estimate, GMP's budget for Distribution Line Blanket needs to be reduced by $10,932,515 which is a 32% reduction GMP's proposed Distribution Lines budget. While I understand the Department is not prepared to recommend full disallowance of blanket costs based on past Commission precedent, I think that the Commission and the Department should give serious consideration to revisiting the allowance of blanket costs under the known and measurable standard in future proceedings. As the charts above demonstrate, the costs for most of GMP's blankets are increasing at a significant rate. GMP's blankets have also subsumed a significant portion of GMP's overall proposed capital spending. I think that it will be important for regulators to continue to track GMP's blanket spending closely and give serious consideration to revising the regulatory practice of including blankets in rates.

The table below shows my modified cost reductions for the blanket work orders.

Summary of Modified Cost Reductions - Blanket Work Orders

Project Category	Proposed Total Cost	Total Cost Reduction in 2019 Blankets	Final Cost
Meters	$1,696,412	$0	$1,696,412
Regulators and Capacitors	$2,074,865	($338,605)	$1736,260
Transformers	$7,320,969	($887,326)	$6,433,643
Distr. Lines Blanket	$33,814,825	($10,932,515)	$22,882,310
Substation	$1,752,964	$0	$1,752,964
Transmission	$2,770,787	$0	$1,713,630
	$49,430,822	**($12,158,446)**	**$37,272,376**

These adjustments can be found in Exhibit PSD-KJM-10.

Q53. Does this conclude your direct testimony?

A53. Yes.