Exhibit No. IMM-0001
Docket No. ER20-2576-001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Holloman Lessee LLC	)	Docket No. ER20-2576-001
	)	

ON BEHALF OF THE
INDEPENDENT MARKET MONITOR FOR PJM

SUMMARY OF DIRECT AND ANSWERING TESTIMONY OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

The purpose of my testimony in this case is to identify flaws in the reactive capability rate proposed by the applicant and to explain why the generating facilities in these proceedings are not eligible to receive the requested compensation from PJM Interconnection, L.L.C. under Schedule 2 to the PJM Open-Access Transmission Tariff ("Schedule 2"). Schedule 2 is provided as Exhibit No. IMM-0002.

The out of market payment requested by Holloman, $2,092,141.05 per year, or $22,022.54 per MW-Year, or $60.34 per MW-day, is excessive. The *AEP* Method does not apply to solar facilities and should not be used to define the reactive revenue requirement for any unit in PJM markets. The capital recovery factor used by Holloman to translate the capital investment into an annual revenue requirement is incorrect and not adequately supported.

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DIRECT AND ANSWERING TESTIMONY OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

Q 1. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Joseph E. Bowring. I am the Market Monitor for PJM. I am the President of Monitoring Analytics, LLC. My business address is 2621 Van Buren Avenue, Suite 160, Eagleville, Pennsylvania. Monitoring Analytics serves as the Independent Market Monitor (IMM) for PJM, also known as the Market Monitoring Unit (MMU or Market Monitor). Since March 8, 1999, I have been responsible for all the market monitoring activities of PJM, first as the head of the internal PJM Market Monitoring Unit and, since August 1, 2008, as President of Monitoring Analytics. The market monitoring activities of PJM are defined in the PJM Market Monitoring Plan, Attachment M and Attachment M-Appendix to PJM Open Access Transmission Tariff (OATT).[1]

Q 2. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the Market Monitor's position on the proposed annual revenue requirement ("ARR") filed in this proceeding by Holloman Lessee LLC ("Holloman") for its 95 MW solar generating facility located in Aulander, North Carolina ("Holloman Facility").

Holloman proposes an annual revenue requirement of $2,092,141.05 per year, or $22,022.54 per MW-Year, or $60.34 per MW-day. The proposed ARR is excessive.

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[1] *See PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247; 18 CFR § 35.34(k)(6).

The proposed ARR is a disproportionately large share of the total capital costs of the resource. The proposed ARR is significantly higher than the average rate paid for reactive power in PJM. The proposed ARR is greater than the clearing price in the last PJM capacity market auction for the Rest of RTO LDA. The proposed ARR exceeds the $2,199 per MW-year level of the ancillary services revenue offset included in the PJM market rules. The ARR should capped at $2,199 per MWh-Year. The proposed annual carrying charge is incorrect and not adequately supported. The Market Monitor has calculated an appropriate capital recovery factor ("CRF").

Q 3. HAVE YOU PROVIDED TESTIMONY ON COMPENSATION FOR REACTIVE POWER IN OTHER PROCEEDINGS BEFORE THE FERC?

A. Yes. I provided testimony in the *Panda Stonewall* reactive supply capability case (Docket No. ER21-1821-002) and the *Whitetail Solar 3, et al.* reactive supply capability case (Docket No. ER20-1851-004 et al.). I provided an affidavit in support of opposition to an offer of settlement in the Meyersdale Storage, LLC, reactive supply capability case (ER21-864-000).

Q 4. HAVE YOU PARTICIPATED IN OTHER FERC PROCEEDINGS RELATED TO REACTIVE POWER?

A. Yes, I was invited to participate in a Commission technical conference and provided comments to the Commission in a proceeding convened to "discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) within the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)."[2] Specifically, the proceeding explored "types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., Commission-approved revenue requirements, market-wide rates, etc.)."[3]

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[2] *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000. I participated in a workshop convened June 20, 2016. The Market Monitor filed comments on July 29, 2016, and reply comments on September 20, 2016.

[3] *Id*. at 1.

On February 22 and March 23, 2022, the Market Monitor filed comments and reply comments responding to the Commission's Notice of Inquiry in Docket No. AD22-2. The Notice of Inquiry included questions (at P 28 (question no. 5.d)) specifically addressing the over recovery issue. The Notice of Inquiry also included questions (at PP 20–28 (question no. 5) addressing the appropriateness of continuing to use the *AEP* Method in reactive capability proceedings, particularly proceedings to establish ARRs for asynchronous generators.

The Market Monitor has intervened in and actively participated in FERC reactive power cases during the past five years.

The Market Monitor includes analysis and recommendations related to reactive power in the State of the Market Reports for PJM.[4]

I.

Q 5. WHY SHOULD THE PROPOSED ANNUAL REVENUE REQUIRMENT BE REJECTED?

A. The proposed payment to the 95 MW Holloman facility (ARR) of $2,092,141.05 per year, or $22,022.54 per MW-Year, or $60.34 per MW-day is excessive.

The *AEP* Method that is typically used in reactive capability proceedings was developed for use with generating facilities that have very different engineering and operational characteristics.[5] Regardless of whether the *AEP* Method is itself appropriate for use in establishing reactive capability costs, there is no corresponding method for defining the reactive capability costs, if any, associated with solar facilities.

Even by the standards of the *AEP* Method, an ARR of $2,092,141.05 per year, or $22,022.54 per MW-Year, or $60.34 per MW-day, is excessive, has not been

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[4] *See*, for example, *2020 State of the Market Report for PJM*, Section 10 (Ancillary Services Markets), which can be accessed at: <*http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml*>.

[5] *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999); *see also Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) ("Notice of Inquiry").

demonstrated to have a rational basis, has not been demonstrated to be just and reasonable, and should be rejected. The average revenue requirement for reactive capability is about $2,000 per MW-year. The revenue requirement for reactive capability included in the PJM Capacity Market is $2,199 per MW-year.

There is no reasonable basis for such a wide disparity in cost for the same service. This result has not been explained or supported by Holloman. This disparity is inconsistent with competitive markets.

II.

Q 6. HOW DO PJM MARKET RULES PROVIDE THE OPPORTUNITY TO RECOVER REACTIVE CAPABILITY COSTS?

A. The PJM market rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR Curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[6] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve.

Q 7. HOW DOES THE $2,199 PER MW-YEAR NUMBER AFFECT THE DEMAND CURVE FOR CAPACITY?

A. Elimination of the ancillary services revenue offset of $2,199 per MW-Year would mean that the prices on the capacity market demand curve (VRR curve) for each MW level would be higher and the clearing prices for capacity that result from the interaction of the supply curve and the VRR curve, would be higher. The result would be the recovery of additional reactive capacity revenues in the price of capacity for all resources.

Q 8. WHY IS THE DEMAND CURVE RELEVANT?

A. If there were no nonmarket recovery of reactive revenue, there would be no reactive revenue offset to Net CONE and the demand curve would result in higher capacity market prices, all else held constant. If there were no nonmarket recovery of reactive

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6 *See* OATT Attachment DD § 5.10(a)(v)(A).

revenue, the shape and location of the demand curve would give unit owners the opportunity to recover all reactive capability costs in the capacity market.

This is how the capacity market works for all the other costs of a generating plant other than short run marginal costs.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The best approach would be to eliminate cost of service rates for reactive capability and allow for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve net CONE value, currently $2,199 per MW-year.

III.

Q 9. SHOULD THE *AEP* METHOD BE USED TO CALCULATE THE RATE FOR THE HOLLOMAN FACILITY?

A. No. The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so. The *AEP* Method is a cost of service allocation approach designed to assign the regulated revenue requirement for generating units to a regulated generation function and a regulated transmission function. The *AEP* Method was designed to split that cost recovery for generating units in a reasonable way, based on a judgment about what is reasonable. The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power. Cost of service approaches apply allocation factors to accounting line items based on assumptions. The assumptions are that X percent of a type of equipment at a generating plant is associated with reactive power while (1-X) percent is associated with real power. The false precision of the *AEP* Method is entirely based on arbitrary assumptions. Even proponents of the *AEP* Method do not assert that the goal is to recover only the costs associated with a specific portion of a power plant required for the production of reactive power, or, in most cases, that such identification is even possible. That is not what the *AEP* Method was intended to do or is intended to do. The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.

The *AEP* Method is based on the incorrect premise that the capacity costs of an integrated power plant are separable. The capacity costs of an integrated power plant are not separable.

The fundamental flaw in the *AEP* Method approach is the assumption that the costs of providing reactive power are a function of the power factor. The power factor is the ratio of real power (expressed as megawatts or MW) to the total output (apparent power) of a generator (expressed as megavolt-amperes or MVA). The remaining output is reactive power (expressed as megavolt amperes reactive or MVAR). The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is $(1 – (\text{PowerFactor})^2)$. The power factor has superficial attraction as an appropriate allocator. The power factor is the core determinant of the reactive allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power. For a power factor of .95, the allocator is 9.75 percent while for a power factor of .90, the allocator is 19.00 percent, and for a power factor of .70, the allocator is 51.00 percent. For a resource claiming a power factor of .70, does that mean that more than half of the generator's costs were incurred in order to provide reactive power? Does this mean that 51 percent of the costs of the generator, exciter, and electrical equipment should be recovered through a cost of service rate? The answer to both questions is no. But resources have filed for guaranteed reactive revenue requirements on that basis.

The power factor has taken on somewhat mythical significance in the discussion of reactive power. There are frequently long discussions of power factors in reactive cases. The ratio of real to reactive power can vary significantly. The typical actual operating power factor of generators in PJM is determined by their voltage schedule and is usually between .97 and .99. The resultant *AEP* Method power factor allocator consistent with this actual reactive output of PJM generators and the actual tariff defined reactive output to generators is 5.91 to 1.99 percent. The nameplate power factor of thermal generating units is typically .85. But the nameplate power factor stamped on the generator at the factory and not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.

The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power. The power factor has taken on a disproportionate significance in reactive rate cases because it is the single most important allocator in the *AEP* Method. That significance illustrates the fundamental flaws in the *AEP* Method.

The power factor does not measure reactive capability. The power factor does not determine a plant's reactive capability. The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.

IV.

Q 10. WHAT ARE THE ISSUES WITH THE COMPANY'S PROPOSED ANNUAL CARRYING CHARGE CALCULATION?

A. Holloman calculates an annual carrying charge which is a form of capital recovery factor (CRF). This CRF was initially presented in the prepared direct testimony of Donald J. Clayton on July 31, 2020 , and then modified in the testimony of W. Wade Horigan on February 28, 2022 . Both Witness Clayton and Witness Horigan derive a fixed charge carrying rate which is the sum of a CRF and a fixed operating expense rate. The latest CRF presented by Witness Horigan is the sum of a sinking fund depreciation factor and the before tax weighted average cost of capital. Witness Horigan's derivation removed the income tax factor that was originally included in Witness Clayton's derivation. Neither derivation accurately reflects the tax liability and the return on and the return of the capital investment.

The CRF is a rate, multiplied by the relevant investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs include as inputs the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes. The Market Monitor's CRF accurately reflects the tax liability associated with the annual payment. The depreciation used in the calculation of the CRF should reflect the depreciation used for tax purposes. The sinking fund depreciation factor does not reflect the actual depreciation used by Holloman and therefore should not be used in the calculation of the revenue requirement for the Holloman facility.

Witness Horigan did not account for the actual tax treatment of the facility and did not adequately explain his tax treatment, did not account for the actual expected life of the facility, did not adequately explain or support his depreciation method, and did not account for the actual cost of capital of the facility.

Q 11. HOW DO YOU PROPOSE TO CALCULATE THE CAPITAL RECOVERY FACTOR (CRF)?

A. The best approach for calculating capital recovery over a defined period is the Capital Recovery Factor (CRF) used by the Market Monitor. I have attached to my testimony as Exhibit No. IMM-0003, a Capital Recovery Factors (CRF) Technical Reference prepared by the Market Monitor. The technical reference explains in detail the components for accurately and consistently calculating a CRF.

The CRF should be required for use in all cost based ratemaking provisions used in PJM, which now include black start service rates and reactive capability rates.

The CRF as proposed by the Market Monitor provides the necessary and sufficient level of revenue to pay the annual tax liability and the return on and return of the capital investment. The CRF approach proposed by the Market Monitor is based on the weighted average cost of capital (WACC) capital budgeting method. Under the WACC approach, the after tax cash flow is discounted at the after tax WACC rate and the payback of the investment in each cost recovery year reflects the defined capital structure. This approach can be efficiently reduced to a single formula for the CRF. FERC accepted this approach for black start service and directed PJM to include the CRF formula in the PJM tariff.[7] Additional details on the derivation of the CRF formula and examples are available in the MMU's CRF Technical Reference.

The Market Monitor used the CRF approach to determine an annual revenue requirement based on the capital cost data and financing structure provided in the Horigan Testimony. The results are shown in Exhibit Nos. IMM-0004 and IMM-0005. For a 20 year cost recovery period, the Market Monitor's CRF is 0.094123 and the corresponding annual revenue payment is $1,303,545.[8] [9] The Market Monitor's CRF is lower than the CRF proposed by Horigan. The Market Monitor's annual revenue payment in Exhibit No. IMM-0004 reflects a reduction to the

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7 *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080 at PP 43–44 (2021).

8 The formula for the CRF is equation (1.4) in the CRF Technical Reference. The calculation assumes the half year convention for the timing of revenue and tax payments.

9 This value reflects the capital cost recovery and does not include fixed operating expenses to protect confidential information.

reactive capital cost to account for an investment tax credit (ITC). It is not clear from the Clayton or Horigan Testimony if an ITC adjustment was applied. The Holloman Solar plant would have been eligible for an ITC and it should be reflected in the reactive cost recovery. The annual payment for capital cost recovery proposed by Witness Horigan apparently does not reflect an ITC. The Market Monitor's payment is lower than the payment proposed by Witness Horigan. The Market Monitor's CRF calculations in Exhibits Nos. IMM-0004 and IMM-0005 reflect 100 percent bonus depreciation that allows generators placed in service after September 27, 2017, to fully depreciate the capital investment in the first year of operation. Exhibit No. IMM-0005 shows the Market Monitor's proposed capital cost recovery assuming a reduction for an ITC is not warranted.

Exhibit Nos. IMM-0004 and IMM-0005 also show the CRFs and corresponding capital recovery payments for recovery periods exceeding 20 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075600. The corresponding annual payment is $1,047,012 under the assumption that the reduction of the reactive capital cost by an ITC is applicable.[10]

Witness Horigan has not explained why a 20 year life rather than a 30 or 40 year life is appropriate for the Holloman facility. It is my experience that comparable solar units frequently assert that they have useful life well in excess of 20 years. Such longer life should be reflected in the CRF.

Witness Horigan has not explained the actual cost of capital for the Holloman facility or explained why the actual cost of capital should not be used in the calculation of the CRF.

The tables in Exhibits Nos. IMM-0004 and IMM-0005 are included to illustrate the implications of the issues with the company's CRF calculations for the annual revenue requirement, based on the assumptions that the company's allocation of costs to reactive are correct. I do not support using the annual revenue requirements in Exhibits Nos. IMM-0004 and IMM-0005, but include the calculations solely for the purpose of showing the implications of the incorrect CRF calculations proposed by Holloman.

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[10] This value reflects the capital cost recovery and does not include fixed operating expenses to protect confidential information.

Q 12. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit IMM-0002
PJM OATT Schedule 2

Exhibit IMM-0003
Capital Recovery Factors
Technical Reference

Exhibit IMM-0004
CRF and Annual Payment–Capital Reduced for ITC

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Horigan Testimonty	$18,740,775	$18,740,775	$18,740,775	$18,740,775	$18,740,775
Investment Tax Credit[1]	$4,891,342	$4,891,342	$4,891,342	$4,891,342	$4,891,342
Capital Cost to be recovered through Reactive Compensation	$13,849,433	$13,849,433	$13,849,433	$13,849,433	$13,849,433
Capital Recovery Factor	0.094123	0.085862	0.080869	0.077690	0.075600
Annual Payment for Capital Cost Recovery	$1,303,545	$1,189,143	$1,119,989	$1,075,966	$1,047,012

[1] Assumes an investment tax credit of 30 percent was applied to 87.0 percent of the capital cost to be recovered through reactive compensation. The percent applicable value of 87.0 percent is the average capital cost ITC eligibility rate the MMU has encountered in its MOPR review related to the PJM capacity auctions.

Exhibit IMM-0005
CRF and Annual Payment–not reduced for ITC

Exhibit IMM-0005
Docket No. ER20-2576-001

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Horigan Testimonty	$18,740,775	$18,740,775	$18,740,775	$18,740,775	$18,740,775
Investment Tax Credit[1]	$0	$0	$0	$0	$0
Capital Cost to be recovered through Reactive Compensation	$18,740,775	$18,740,775	$18,740,775	$18,740,775	$18,740,775
Capital Recovery Factor	0.094123	0.085862	0.080869	0.077690	0.075600
Annual Payment for Capital Cost Recovery	$1,763,931	$1,609,125	$1,515,547	$1,455,976	$1,416,795

[1] Assumes a reduction for ITC is not applicable.

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DECLARATION

JOSEPH E. BOWRING states that I prepared the testimony to which this declaration is attached with the assistance of the staff of Monitoring Analytics, LLC, and that the statements contained therein are true and correct to the best of my knowledge and belief. Monitoring Analytics, LLC, is acting in its capacity as the Independent Market Monitor for PJM.

Pursuant to Rule 2005(b)(3) (18 CFR § 385.2005(b)(3), citing 28 U.S.C. § 1746), I further state under penalty of perjury that the foregoing is true and correct.

Executed on April May 23, 2022.

Joseph E. Bowring