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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S APPLICATION FOR AUTHORITY TO DECREASE ITS PRICES (2015 PURCHASED GAS COST ADJUSTMENT).	**CASE NO. INT-G-15-02** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Intermountain Gas Company's Application.

BACKGROUND

On August 7, 2015, Intermountain Gas Company (the "Company") filed its annual Purchased Gas Cost Adjustment ("PGA") Application. The PGA adjusts rates each year to reflect changes in the Company's costs to buy natural gas from suppliers—including transportation, storage, and other related costs. *See* Order No. 26019. A change in the PGA does not affect the Company's earnings. But a PGA change can cause customer rates to go up or down. With this Application, the Company proposes to *decrease* overall prices for customers and *decrease* the Company's annualized revenues by $15.3 million (5.69%).

In summary, the Company proposes to pass through to customers gas-related cost changes that would *decrease* the average bill of: (1) residential customers who use natural gas for space heating and water heating, by $3.12/month (6.11%); (2) customers who use gas for space heating only, by $1.36/month (3.56%); and (3) commercial customers by $12.15/month (5.66%). The Company proposes that the new rates take effect October 1, 2015.

The Company explains that its proposed price changes incorporate all changes in costs relating to the Company's firm interstate transportation capacity including, but not limited to, any price changes or projected cost adjustments implemented by the Company's pipeline suppliers as well as any volumetric adjustments in contracted transportation agreements which have occurred since the Company's last PGA filing, Case No. INT-G-14-01.

The Company notes that its Application includes $1.4 million related to the Company's acquisition of more liquefied natural gas ("LNG") storage capacity at its Plymouth facility on Northwest Pipeline's delivery system. The Company acquired incremental Plymouth capacity of 378,900 MMBtu with a daily deliverability of 41,975 MMBtu. The Company states that the Plymouth facility has been a valuable asset given its ability to help ensure supply and delivery to customers.

The Company proposes decreasing the weighted average cost of gas used to calculate its PGA rates ("WACOG") from the currently approved $0.39482 per therm to $0.32764 per therm. The Company explains the existence of significant North American shale reserves and slow growth of the nation's economy contributed to the WACOG decrease, and that natural gas supplies combined with significant storage balances have kept natural gas prices lower than they were just a year ago. The Company states that it has entered into fixed price agreements to lock in the price for significant portions of its underground storage and other winter "flowing" supplies.

The Company seeks to pass through to its customers, as per therm credits, $3.9 million that will be generated from the management of its transportation capacity. The Company also proposes to temporarily adjust prices for 12 months – until September 30, 2016 – to allocate deferred gas costs from its Account No. 191, including: (1) a fixed gas cost debit of $1.1 million; (2) a variable gas cost debit of $0.7 million; and (3) a Lost and Unaccounted For Gas ("LAUF Gas") credit of $76,166.

The Company states that the proposed overall price changes reflect a just, fair, and equitable pass through of changes in gas-related costs to the Company's customers. The Company states that it has notified customers about the Application and price changes through a formal Customer Notice and a Press Release.

STAFF ANALYSIS

Staff examined the Company's Application and gas purchases for the year. Staff confirms that the Company's PGA proposal would not change the Company's earnings, the Company's deferred costs are prudent, and the Company's WACOG is reasonable.

In this PGA filing, the Company proposes lowering customer rates which will decrease the Company's annualized revenues by 5.69% or $15.3 million. The Company explains that the gas-related cost changes result from: (1) transportation costs billed to the Company by Northwest Pipeline GP, an interstate gas transportation provider whose pipeline runs through the Company's service teritory; (2) a decrease in the Company's WACOG, (3) an updated customer allocation of gas-related costs under the Company's PGA provision; (4) the inclusion of temporary surcharges and credits for one year relating to natural gas purchases and interstate transportation costs from the Company's deferred gas cost accounts; and (5) benefits resulting from the Company's management of its storage and firm capacity rights on various pipeline systems. Tables 1 and 2, below, summarize the Application's proposed changes by customer class and their effects on the Company's overall base rates and prices:

Table 1: Summary of proposed changes

Customer Class:	**Revenue Change**	**$ Per Therm Change**	**% Average Change**	**Average Price $/Therm**
RS-1 Residential	$(1,118,517)	(0.03233)	-3.56%	$0.87654
RS-2 Residential	$(8,875,757)	(0.04851)	-6.11%	$0.74522
GS-1 General Service	$(4,580,524)	(0.04146)	-5.66%	$0.69049
LV-1 Large Volume	$(248,722)	(0.04284)	-7.97%	$0.49494
T-3 Transportation	$(117,637)	(0.00152)	-8.28%	$0.01683
T-4 Transportation	$(354,247)	(0.00206)	-4.78%	$0.04101
T-5 Transportation	$(30,876)	(0.00168)	-60.22%	$0.00111
	$(15,326,280)	**(0.02548)**	**-5.69%**	**$0.42256**

Table 2: Effect of proposed changes

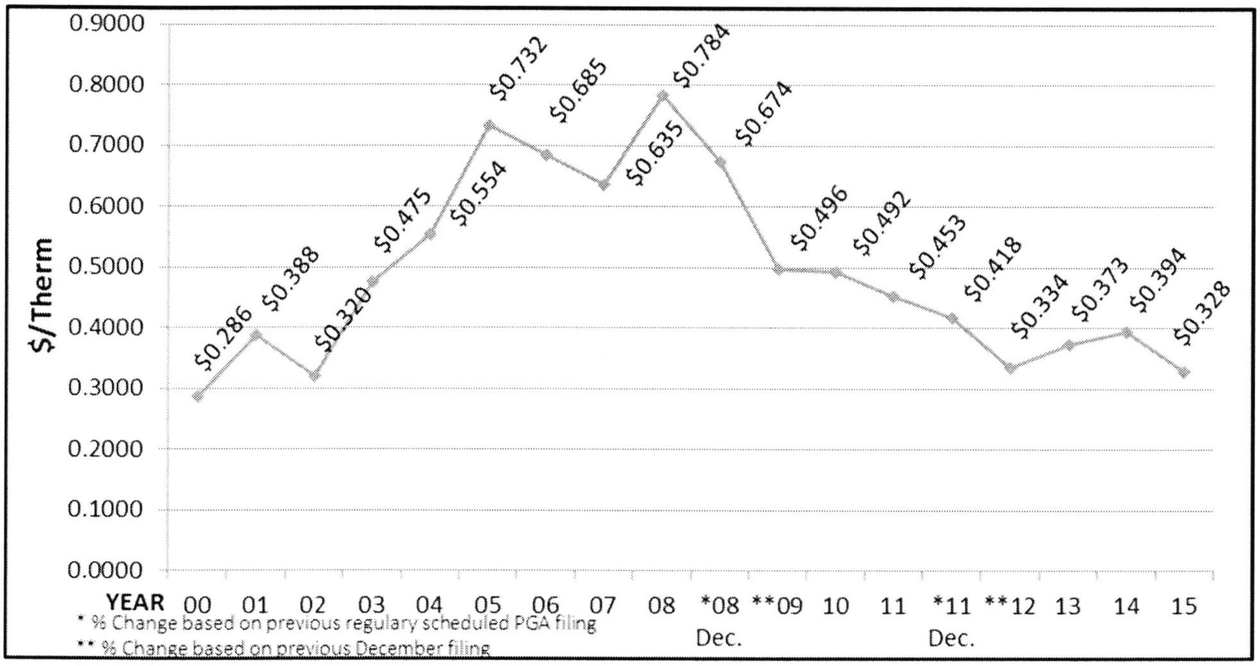
Deferrals:		
Removal of INT-G-14-01 Temporary Credits and Charges		$10,114,746
Additional INT-G-15-02 Temporary Credit and Charges		
Fixed deferred Gas Costs	$(2,889,972)	
Variable Deferred Gas Costs	$696,361	
Lost and Unaccounted for Gas	$(989,783)	
LNG Sales Credit	$(689,367)	
Total Additional Temporary Credit and Charges		$3,872,761
Total Deferrals		***$6,241,985***
Fixed Cost Changes:		
NWP Full Rate Reservation	$1,545,062)	
NWP Discounted Reservation	$(483,850)	
Upstream Full Rate	$(525,768)	
Upstream Discounted	$748,711	
SGS & LS	$1,390,722	
Total Fixed Cost Changes	***$2,674,877***	
Re-allocation of Fixed Costs	$(1,815,042)	
Changes in WACOG	$(22,428,100)	
Total Base Rate Changes		***$(21,568,265)***
Total Annual Price Change		***$(15,326,280)***

Weighted Average Cost of Gas (WACOG):

The WACOG is the Company's average variable cost to buy and transport gas to satisfy its customers' estimated annual gas requirements. The WACOG includes the volumetric interstate transportation rate, city gate costs, IGI Resources administrative fees, and Gas Technology Institute (GTI) charges. It does not include fixed capacity costs for interstate transportation, liquid storage, and underground storage. The WACOG is roughly 68% of the Company's total annual gas cost. The WACOG proposed price is $0.32764 per therm which is $0.06718 per therm lower than the price of $0.39482 per therm reflected in current tariffs.

The Company injects most of its natural gas into storage for use during the following heating season before filing the annual PGA. Consequently, the Company's estimated stored-gas cost when it files the PGA is similar to its actual stored-gas cost, because most of those costs are locked-in and will not fluctuate with the market. The Company maintains that it can withdraw about 28% of its storage injections during the heating season at a WACOG of $0.3413 per therm. Similarly, the Company can obtain about 39% of its weather normalized throughput for the heating season from "flowing gas supplies" that have been hedged at a WACOG of $0.3088 per therm. The supplies that have not been hedged are estimated based upon an independent, third-party price forecast. Chart 1, below, describes the WACOG:

Chart 1: Weighted Average Cost of Gas (Per Therm)



Market Fundamentals & Price Analysis

Although the Company has hedged or stored most of its forecasted throughput at fixed prices, market fluctuations can impact the WACOG. Staff thus analyzed the Company's projected cost to purchase natural gas. Staff compared the Company's forecast to forecasts from national and regional organizations, including the Energy Information Administration ("EIA"), the Northwest Gas Association ("NWGA"), and the Northwest Power and Conservation Council ("NWPCC").

The EIA projects Henry Hub prices will increase from an average of $2.84/MMBtu in 2015 to $3.11/MMBtu in 2016. Additionally, the EIA predicts increased average consumption in 2015 (76.5 Bcf/d) and 2016 (76.6 Bcf/d) over 2014 (73.5 Bcf/d). The increases in 2015 and 2016 are primarily attributed to electricity generation and new industrial projects. However, natural gas consumption is projected to decline in both the residential and commercial sectors.

The NWGA published an abbreviated Outlook for 2015 because trends identified in its 2014 publication continue to be relevant. Additionally, key conclusions and analyses are consistent with current conditions. NWGA's 2015 Gas Outlook key conclusions on the supply side are that shale plays continue to transform the energy landscape, production techniques exceed expectations, and Pacific Northwest natural gas customers benefit from being near two large natural gas producing areas. On the price side, both spot and future commodity prices reflect growth in North American natural gas production, natural gas has a price advantage over diesel and petroleum, and most long-term price forecasts have declined since 2008.

Staff developed its own forecast using the NYMEX/NGX Futures prices at each of the three hubs where the Company buys natural gas. Utilizing the Company's estimated volume allocation percentages for each hub, Staff forecasts the volume-weighted cost of gas to be \$3.184/MMBtu. The Company's forecasted mainline fuel cost of \$3.178/MMBtu is comparable to Staff's forecast. The Company's forecasted delivered fuel cost of \$3.276/MMBtu is higher than its mainline fuel cost because the proposed WACOG includes variable interstate transportation costs, IGI administrative fees, and Gas Technology Institution ("GTI") charges.

Based on Staff's analysis of the market, weighted average cost of the Company's hedges, and estimated cost of forward-looking index Company purchases, Staff believes that the Company's WACOG of \$0.32764 per therm is reasonable. Staff recommends that the Commission accept the proposed WACOG and direct the Company to return to the Commission with a new filing if prices significantly deviate from proposed rates during the forthcoming year.

Risk Management

Staff analyzed the Company's operations and business practices to determine whether the Company purchased gas at market prices and minimized risk to ratepayers. Staff scrutinized how the Company manages price and risk given the Company's market purchases, storage, and interstate transportation capacity.

The Company fulfills its mainline requirement with hedges, spot market purchases, underground storage, and LNG storage. Underground storage enables the Company to purchase gas for the upcoming heating season during the summer when natural gas prices are typically lower. When opportunities are present, the Company manages its interstate transportation capacity, selling surplus in the market. The Company sold LNG from its storage facility providing customers with a $689,367 PGA credit while maintaining LNG to meet peak day gas demands. This is an increase of $283,956 or 70% over 2014 sales of $405,411.

Overall, the Company's strategy and practices associated with managing its resource portfolio provide price stability for customers. The Company's approach is flexible, which allows it to opportunistically buy gas, manage storage, and utilize interstate transportation capacity as market conditions change.

Purchasing

Staff analyzed the Company's purchasing practices to determine if the Company reasonably adapted them to meet current market conditions. When compared to last year, the Company plans to purchase a larger percentage of its mainline throughput requirement using index or spot purchases. About 32% of the Company's total throughput are index or spot purchases, compared to 28.3% last year. The Company's hedged supply went from 44.1% of total throughput last year to 46.7% this year. Including the Company's storage gas, about 68% is essentially hedged which is 4% lower than last year. The Company increased its hedging ratios during the non-summer months, but decreased its hedging ratios in the summer months. This is shown in Table 3, below:

Table 3: WACOG Hedging Ratios

% Locked-in Gas by PGA Year[1]						
	2010	2011	2012	2013	2014	2015
Non-Summer Months (Oct.-Mar.)	68	69	63	79	74	78
Summer Months (Apr.-Sept.)	29	0	45	48	63	22
Full Year	59	52	59	71	72	68

Staff believes the Company's hedging ratio adjustments compliment current market conditions, particularly since natural gas prices declined in the summer. The Company continues to utilize index or spot purchases, but Staff believes the Company can react to upward price risk since most of the Company's hedged volumes are locked-in at reasonable prices.

[1] % Locked-in gas includes storage volumes that are both hedged and index purchases.

Natural Gas Underground Storage

The Company says its management of storage assets benefits customers. Management of the Company's storage assets at Northwest Pipeline's Jackson Prairie and Questar's Clay Basin result in $1.8 million savings. Because gas added to storage is procured during the summer season when prices are typically lower than during the winter, the Company's cost of storage gas is typically lower than what could be procured in winter months. The Company has also entered into various fixed price agreements for portions of underground storage and other winter flowing supplies to further stabilize prices.

Staff analyzed the Company's practices for utilizing underground storage. When compared to last year, the Company plans to withdraw slightly more of its underground storage to meet total throughput. Last year, stored gas served about 27.4% of total throughput, whereas this year it is expected to serve 27.7% of total throughput.

LNG Storage

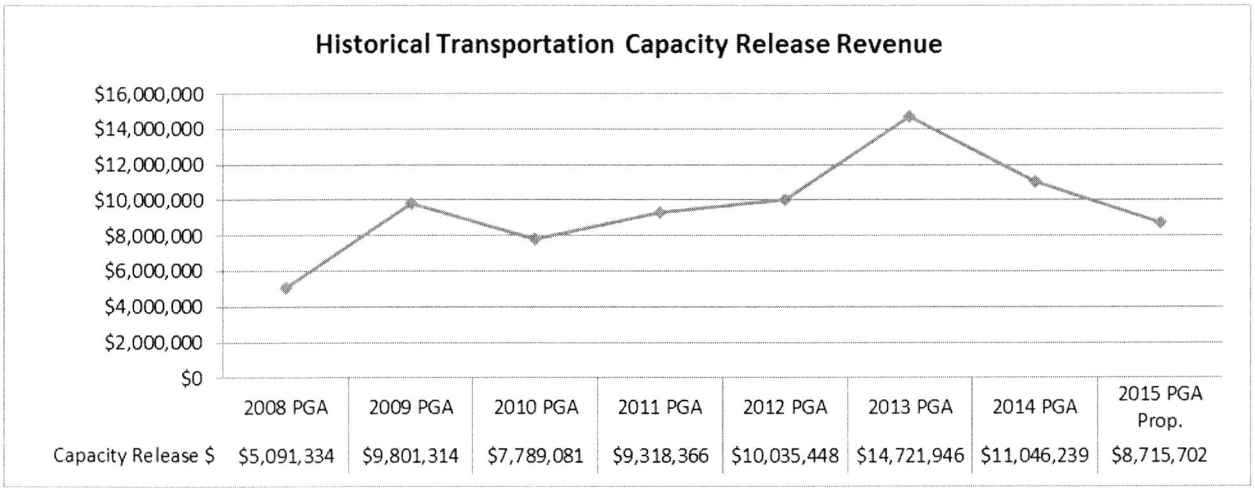
The Company's Application includes $1.4 million for additional LNG storage capacity at the Company's Plymouth facility on the Northwest Pipeline system. The Company acquired incremental capacity of 378,000 MMBtu, with daily deliverability of 41,975 MMBtu. The Company states that: "In addition to the operational and price mitigating benefits this added capacity brings to Intermountain's customers, had this incremental Plymouth capacity not been subscribed to, Intermountain would have been faced with a rise in costs associated with its existing (lower) Plymouth capacity in excess of the costs associated with this incremental acquisition."

Interstate Transportation

The Company delivers domestically produced natural gas to its city gates through Northwest Pipeline. The Company also delivers natural gas from Canada by using capacity on Gas Transmission Northwest (GTN), TransCanada's Foothills Pipeline system (Foothills), and TransCanada's Alberta system known as Nova Gas Transmission (NOVA).

When the Company has excess capacity, it sells the surplus gas at the highest market price available that day. All the benefits made from these sales are credited to customers. Staff analyzed the Company's historical capacity release revenue to determine annual variability. The Company's proposed revenue from capacity releases this year totals $8,715,702, which includes revenues from releases on a segment of Northwest Pipeline and non-segmented releases on pipelines delivering natural gas from Canada. Staff determined that this capacity release revenue is $849,227 below an eight year average of $9,564,929. Staff encourages the Company to aggressively market its surplus capacity when it is available. Chart 2, below, describes the Company's revenue from capacity release:

Chart 2: Transportation Capacity Release Revenue



Lost and Unaccounted for Gas (LAUF Gas):

LAUF Gas is the difference between the volumes of natural gas delivered to the distribution system at the city gate and volume of gas billed to customers at the meter. The Company recovers LAUF Gas amounts through a per therm surcharge if the amount is above what was included in Commission-approved base rates. Conversely, the Company credits customers if the amount is below what was included in base rates.

This year, the Company estimates about 2.3 million therms of LAUF Gas, or 0.394% of total throughput, below the maximum allowable amount of LAUF Gas specified in Commission Order No. 30649.[2] The total normalized level of LAUF Gas embedded in base rates yields $1,055,711 of LAUF Gas already collected.[3] The Company wants to return the difference between the $1,055,711 normalized level of LAUF Gas already collected through base rates and

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[2] The Company uses actual LAUF Gas results through August and estimates the amount of LAUF Gas from October through September. Commission Order No. 30649 caps the Company's allowable LAUF Gas at .85% of throughput.

[3] In 1985, the Commission established $0.00182 per therm as the normalized unit cost that can be collected for LAUF Gas as a part of base rates.

the total estimated October 2014 to September 2015 LAUF Gas of $1,131,877. The difference, or the over-collection, will be a $76,166 credit to customers.

In the past, to retrospectively audit the Company's actual LAUF Gas percentage of overall throughput, Staff requested a modified workpaper to provide a full year view of actual LAUF Gas. Last year, the Company agreed to provide a workpaper in its Application that retrospectively looks at the actual LAUF Gas percentage of overall throughput. Starting with this filing, the Company provided Workpaper No. 7 in its Application which retrospectively looks at the actual LAUF Gas percentage of overall throughput. Actual October 2013 through September 2014 LAUF Gas was 880,946 therms or 0.143% of throughput. Projected LAUF Gas for October 2014 through September 2015 is 2,288,309 therms or 0.394% of throughput.

Line Break-Lost and Unaccounted for Gas

Last year, Staff discovered instances where the Company inadvertently charged the incorrect rate for gas lost due to line breaks. In some instances, the Company used only the WACOG to bill the responsible party. Order No. 33139 states "the Company shall bill a party who is responsible for a line break to price lost gas using the WACOG and the RS-l fixed-cost of interstate transportation and storage." The Company planned to hard code the price of gas into an electronic system, so the price remains fixed throughout the PGA year and need not be manually entered for each occurrence.

Staff audited the Company's LAUF Gas based on Case No. INT-G-14-01 (2014 PGA). Staff concluded that the Company implemented hard coding of the lost gas price into its LAUF policies, operating procedures, and software. Additionally, Staff examined accounting records and Gas Loss Reports from October 7, 2014 through June 30, 2015. Staff concluded that the accounting system and Loss Gas Reports are consistent and reflect the same cost for lost gas.

The current price of LAUF gas includes a fixed-cost component of $0.22841 (Fixed-Cost Collection Rate) per therm and a variable component of $0.39482 (WACOG) for a total of $0.62323 referred to as the Line Break Rate. The Company proposes to decrease the Line Break Rate from $0.62323 per therm to $0.55674 per therm. The proposed Fixed-Cost Collection Rate is $0.22910 per therm and the proposed variable component is the WACOG of $0.32764. Both components of the Line Break Rate are determined annually with the PGA filing. Staff concluded that the Company correctly calculated the proposed Line Break rate.

Demand Allocation Factors

Last year, Staff discovered the Company exceeded the December 2009 peak day usage in December 2013. Staff thus recommended that the Company update its peak demand allocation factors in the PGA filing following a new peak day. Through discovery, Staff learned the Company reviewed peak days before filing. According to the Company, the peak day for 2014 was 58 heating degree days which is warmer than the peak day of 63 heating degree days for 2013. Therefore, the Company continued to use the 63 heating degree days from 2013 as the peak day for this filing.

CUSTOMER RELATIONS

Credit Customer Notice and Press Release

The Company's press release and customer notice were included with its Application. Staff reviewed the documents and determined that both comply with Rule 125 of the Commission's Rules of Procedure, IDAPA 31.01.01.125.

The customer notice was included with bills mailed beginning August 10 and ending September 4. Customers have the opportunity to file comments on or before September 16, 2015.

Customer Billing

The Company recently implemented a new Customer Care and Billing System. Among the resulting changes was a new billing format. The new format provides customers with information previously unavailable on bills, e.g., a 13-month usage history, a calendar highlighting the payment due date, and an improved layout that makes it easier to find account information.

Staff is concerned, however, about changes in how the Company itemizes charges. For example, the residential bill now breaks down the commodity charge into three separate components: (1) WACOG; (2) pipeline costs and temporaries; and (3) distribution charge. Previously, customer bills reflected a commodity charge with no breakdown of components. The Company's tariff provides for a commodity charge, noting that the charge includes the annual PGA adjustment and the WACOG. Staff notes that the residential tariff does not mention pipeline or distribution costs.

The new billing format came to Staff's attention less than two weeks before the Company's scheduled system implementation date of August 3 – too late in the process to make changes. Staff has determined that the three itemized charges add up to the total cents per therm charge authorized by the Commission as stated in its current tariff. The Company has not proposed to change its tariff format to break out charges in a manner that differs from past practice. As it stand now, however, Staff cannot consult the Company's tariff to verify the accuracy of each separately itemized charge as it appears on customer bills.[4] In addition to the inability to verify charges, Staff is concerned about the increased complexity of customer bills.

The Company has agreed to work with Staff to resolve these billing and tariff issues after this case has concluded.

Customer Comments

As of September 16, 2015, the Commission has received no comments from customers.

STAFF RECOMMENDATION

After examining the Company's Application, exhibits, workpapers, and gas purchases for the year, Staff recommends the Commission approve the Company's Application and filed tariffs to decrease the Company's annual revenue by $15.3 million (5.69%) and establish a WACOG of $0.32764 per therm.

Additionally, Staff recommends that the Company and Staff work together to resolve billing and tariff issues resulting from the Company's recent change in bill format.

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[4] The tariff does note the WACOG included in the commodity rate.

Respectfully submitted this 16th day of September 2015.

Karl T. Klein
Deputy Attorney General

Technical Staff: Terri Carlock
Daniel Klein
Kevin Keyt

i:umisc/comments/intg15.2kktcdkksk comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 16th DAY OF SEPTEMBER 2015, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-15-02, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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