Before the Public Service Commission
of Kentucky

Rebuttal Testimony

of

Dmitry Balashov

on behalf of

Liberty Utilities Co.

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LIBERTY UTILITIES CO.
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2021-00481

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dmitry Balashov. My business address is 354 Davis Road, Oakville, Ontario.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Liberty Utilities (Canada) Corp. ("Liberty Canada") as a Senior Director, Grid Modernization.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Liberty Utilities Co.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I hold a bachelor's degree in Political Science from the University of British Columbia in Vancouver, BC, Canada that I completed in 2005. I also obtained a master's degree in Public Administration from Queen's University in Kingston, ON, Canada, in 2008. Finally, I obtained an Executive Master of Business Administration (MBA) degree from the Rotman School of Management at the University of Toronto, Canada, which I completed in 2018. I started my electricity sector career in 2007, at the Transmission and Distribution Policy Division of Ontario's Ministry of Energy, where I held several advisory positions in support of both infrastructure planning and regulatory policy matters. Between 2013 and 2017, I worked for Toronto Hydro Electric System Limited (THESL) – Canada's largest electricity distribution utility, where I worked as a Lead of Process and Analytics. My position primarily entailed identifying, obtaining regulatory approval for, and implementing a variety of operating and capital planning and asset management initiatives aimed at enhancing system reliability and reducing labor expenditures underlying both O&M and capital budgets. Between 2017 and February of 2021, I worked as a Director of Utility Strategy and Economic Regulation at METSCO Energy Solutions – a utility sector engineering and asset management consulting company. My primary area of responsibility was development of risk-based asset management plans that helped T&D utility customers identify, pace, and prioritize the highest-value capital projects and maintenance program enhancements, based on objective quantitative analysis of asset health, connectivity, and reliability performance. I joined Liberty in February of 2021 as a Senior Director of Policy and Strategy and have transitioned to my current role as the Senior Director of Grid Modernization in February of 2022.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY?

A. I have not. I have, however, provided oral testimony as an independent expert in capital planning and asset management before the Manitoba Public Utilities Board, and prepared written testimony for the Alberta Utilities Commission and the Ontario Energy Board. These entities are independent utility sector regulators with mandates similar to those of the Public Service Commission of Kentucky. Aside from the jurisdictions mentioned, I have also authored reports and capital program planning deliverables that have been submitted to electricity sector regulators in Maine, Arizona, Missouri, Nova Scotia, Saskatchewan, and the Yukon.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to several dimensions of Lane Kollen's testimony. First, I address Mr. Kollen's estimation of the claimed cost increases that Kentucky Power will face due to the loss of scale economies that he attributes to its relationship with AEP. I then address Mr. Kollen's evidence that he provides in support of what he characterizes as Kentucky Power's under-investment in the distribution system and the ensuing requirement for a payment to compensate for that under-investment. Finally, I address Mr. Kollen's testimony regarding the alleged cost increases associated with the current lack of agreements related to spare parts sharing and coordination between Liberty's affiliates and supply chain more broadly.

II. MR. KOLLEN'S ARGUMENT ON THE LOSS OF SCALE ECONOMIES DUE TO THE PROPOSED TRANSACTION DOES NOT WITHSTAND CLOSER SCRUTINY.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S ESTIMATE THAT KENTUCKY POWER'S OPERATING EXPENSES WILL INCREASE BY 5-10% DUE TO THE LOSS OF ECONOMIES OF SCALE THAT HE ATTRIBUTES TO THE COMPANY'S RELATIONSHIP WITH AEP AND ITS SERVICE COMPANY?

A. At a minimum, Mr. Kollen's argument is not particularly well supported. First, Mr. Kollen provides examples of two past M&A transactions in Kentucky where participants estimated the *potential* savings at the time of the transactions being reviewed, rather than citing the *actual* savings achieved. While I have not been able to obtain the data that would confirm what (if any) actual savings these transactions have achieved, and Mr. Kollen has not provided it, it is clear that comparing estimates of savings expected to be gained in some transactions to represent the magnitude of savings expected to be lost in another transaction is highly problematic. All other things equal, setting out expectations of savings on the basis of actual savings achieved in comparable transactions is an approach that warrants consideration. When savings expectations are set out based on other transactions' savings expectations, we are actually basing hypotheticals on earlier hypotheticals; and as I show below, hypotheticals are of questionable relevance to the transaction at hand.

I would also be remiss not to point out the double standard that Mr. Kollen exhibits around this issue. While he thinks it appropriate to use the estimates of potential savings from one transaction as the basis for what amounts to a definitive monetary penalty in another, Mr. Kollen is quick to dismiss the estimates provided by others.[1] Meanwhile, Liberty's analysis is far more granular and relevant to the cost structures of both the acquiring entity and the utility being acquired than Mr. Kollen's examples from Kentucky.

Q. DOES MR. KOLLEN PROVIDE ANY INFORMATION ON ACTUAL SAVINGS ACHIEVED THROUGH OTHER MERGERS AND ACQUISITIONS (M&A)?

A. He does, but this information is even more problematic. In his testimony, Mr. Kollen states that studies in other jurisdictions have found that actual M&A savings have ranged from 3-40%.[2] This stated range is very significant, since Mr. Kollen uses it to characterize his own estimate of a 5-10% cost increase due to the loss of scale economies as "conservative."[3] However, an analysis of the sources of Mr. Kollen's "conservative" estimate reveals that his estimate is actually based entirely on unfounded speculation.

Q. HAVE YOU ANALYZED THE SOURCE MR. KOLLEN CITES FOR THIS 3-40% "INDUSTRY ESTIMATE"?

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[1] Kollen Direct, p.26, lines 11-12.
[2] Kollen Direct, p.25, lines 20-21.
[3] Kollen Direct, p.27, line 8.

A. Yes, I have. The source happens to be Mr. Kollen's own testimony from a 2016 M&A proceeding in Utah, which I have attached to my testimony as **Exhibit DB-R1**.[4] A closer look at that testimony reveals that the high end of Mr. Kollen's range of potential savings (i.e., 40%) comes from his own account of just two acquisitions of small *natural gas* distributors by the same applicant seeking to make the acquisition. It is completely inappropriate to compare natural gas utility O&M costs with those of electric utilities, given the range of expenditures associated with above-ground assets that are simply absent in natural gas systems, the reliability standards to which the two types of services are built, and the complexity of the electricity generation-transmission-distribution overall value chain. The 40% savings estimate as Mr. Kollen presents it has no relevance to this transaction.

Q. WHAT ABOUT THE LOW END OF THE ESTIMATE THAT MR. KOLLEN CITES?

A. The low end (i.e. 3%) comes from a study performed by Concentric Energy Advisors in a 2014 Public Service Commission of Wisconsin M&A docket. I have included Concentric Energy Advisors' Chairman and CEO John Reed's direct testimony from that proceeding in **Exhibit DB-R2.** Upon closer review, the Concentric Study that Mr. Kollen relied on in the Utah filing states that the 3-5% range comes from analysis of savings that "were, *or were expected to be*, achieved in recent mergers" (emphasis added) and over a timeframe as long as 6-8 years.[5] Thus, once again. Mr. Kollen is including expected savings. Notably,

[4] Direct Testimony of Lane Kollen before Public Service Commission of Utah in Docket No. 16-057-01.
[5] Direct Testimony of John Reed in support of application by Wisconsin Energy Corporation p. 35 line 3.

Mr. Kollen's Utah testimony that references this study does not acknowledge this important nuance and instead presents the findings as actuals.[6]

Q. WHAT DO THESE FINDINGS ABOUT MR. KOLLEN'S SOURCES OF INDUSTRY M&A SAVINGS MAKE YOU CONCLUDE?

A. A closer look at Mr. Kollen's supporting documentation and analysis shows that they are completely unreliable and should be dismissed without further consideration, along with the ensuing dollar value of between a $76.7 and $153.4 million increase in operating expenses that Mr. Kollen "forecasts" for the present transaction to justify a portion of the payment amount he and Mr. Baron advance as the condition of this deal. To recap:

- The two past Kentucky cases that Mr. Kollen references as examples of positive synergies are in fact based on estimates made at the time of the transactions having been reviewed by the Commission.
- The 5-10% estimated savings range Mr. Kollen uses in this proceeding is not conservative as he claims, given that the high end of his "industry" range of estimates comes from two very specific and inapposite examples of small natural gas utilities.
- The 3-5% range of industry savings that he claimed in his Utah testimony cited in this case as being "actual" savings in fact reflect a mix of actual and estimated values.

To use Mr. Kollen's own words, his effort to calculate the synergies that he believes would be lost through this transaction amounts to "analysis driven by aspirational assumptions, not an actual and realistic study of the Company's cost structure."[7] The Commission should not base its decision on his pure speculation.

Q. IS THERE ANY OTHER INFORMATION THAT CALLS INTO QUESTION MR. KOLLEN'S CLAIM THAT LIBERTY'S ACQUISITION OF KENTUCKY POWER

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[6] Direct Testimony of Lane Kollen before Public Service Commission of Utah in Docket No. 16-057-01 p.37 of 48, line 904.
[7] Kollen Direct, p.26, lines 11-12.

WOULD RESULT IN SIGNIFICANT INCREASES TO THE COMPANY'S NON-FUEL O&M COSTS BECAUSE OF THE LOSS OF SCALE ECONOMIES?

A. There is, namely the cost structures of one of Liberty's own electric affiliates, The Empire District Electric Company (Empire Electric). As mentioned in Witness Landoll's Direct Testimony, Empire is comparable to Kentucky Power on multiple dimensions as highlighted in the following table.

Category	**Kentucky Power**	**Empire Electric**
Customer Count	166,000	177,000
Peaking Season	Winter	Winter
Transmission Line Miles	1,236	1,127
Distribution Line Miles	10,032	6,372
Owned Generation (MW)	1,075	2,025

As the table suggests, the two utilities share a number of key comparable parameters. While Kentucky Power has a larger distribution system, Empire Electric has a larger owned installed generating capacity and a larger customer count, with both companies' transmission systems being of comparable size. An important difference not captured in this table is what Mr. Kollen argues amounts to degree of services centralization. While Kentucky Power is deeply integrated with AEP's centralized operations, Empire Electric is integrated into the comparatively smaller Liberty shared services model to approximately the same degree as Kentucky Power would be should this transaction be approved.

Q. WHAT WOULD MR. KOLLEN'S SCALE ARGUMENT EXPECT FROM THE TWO UTILITIES' COST STRUCTURE GIVEN THEIR DEGREE OF CENTRALIZATION?

A. Based on Mr. Kollen's logic as I understand it from his testimony, Kentucky Power's greater degree of integration with its much larger parent should result in it having lower non-fuel O&M costs than Liberty.

Q. DOES THE ACTUAL COMPARISON OF THE TWO UTILITIES' COSTS SUPPORT MR. KOLLEN'S LOGIC?

A. It does not. In fact, Empire Electric's non-fuel O&M costs are lower than Kentucky Power's on both nominal and unitized basis.[8] Looking at unitized O&M per customer metrics, which Mr. Kollen uses elsewhere in his testimony, Empire Electric's 2020 costs are $91 lower per customer than those of Kentucky Power ($1,528 vs. $1,618).

Recent Years Non-Fuel O&M Costs[9]

	2020	**2019**	**2018**	**Average**
Kentucky Power	$ 268,748,606	$ 303,974,720	$ 323,081,969	$ 298,601,765
Empire Electric	$ 270,442,912	$ 277,843,796	$ 296,633,908	$ 281,640,205

It may also be instructive to compare these metrics a few years back, when Empire Electric was truly a standalone utility and one of the smallest Investor Owned Utilities (IOUs) in the United States. At the time, it was devoid of a corporate parent or service company to share the benefits of scale with. Once again, and contrary to Mr. Kollen's assertion, a standalone Empire, devoid of any corporate scale benefits, has lower non-fuel O&M costs than Kentucky Power in 2015 and 2016 (the last two years before Empire Electric's acquisition by Liberty):

[8] The analysis uses both utilities' FERC Form 1 filings.
[9] These numbers were derived from the utilities' respect FERC Form 1 filings.

Non-Fuel O&M Costs – Standalone Empire Electric

	2015	**2016**
Kentucky Power	$319,430,187	$316,708,452
Empire Electric	$276,309,912	$254,738,995

It is also worth noting that while this analysis uses non-fuel O&M, to mirror the logic used by Mr. Kollen, development of renewable generation into Kentucky Power's generation fleet would work to reduce over time the fuel expense which is a significant and highly fluctuating category of expense.

Q. WHAT DOES THE COMPARISON OF EMPIRE'S AND KENTUCKY POWER'S O&M COSTS SUGGEST ABOUT MR. KOLLEN'S ARGUMENTS ON SCALE AND DEMANDS FOR THE MONETARY COMPENSATION OF THIS SCALE BEING LOST?

A. It suggests that even the most readily available example, which is also highly relevant in the context of this proceeding, contradicts Mr. Kollen's theory that the larger the utility's parent company and the more services it provides, the more scale economies can be expected from that relationship for the customers. Empire Electric and Kentucky Power are similar enough that the scale advantage that Mr. Kollen believes exists would show up in a head-to-head comparison like this one.

Q. ARE YOU SUGGESTING THAT THERE ARE NO BENEFITS OF SCALE ECONOMIES IN KENTUCKY POWER'S CURRENT COST STRUCTURE?

A. No, but I am suggesting that the relationship is far more complex than the simplistic result-oriented argument that Mr. Kollen makes in his testimony. This, in turn, makes his ensuing recommendation of an AEP payment to compensate for the purported scale losses to be without basis. There are certainly some scale benefits across some of the integrated AEP's functions, but they are not as clear-cut as what Mr. Kollen appears to suggest with his self-serving analysis. Utility operations management is a highly complex and often dynamic undertaking that is very different than the controlled world of factory floor operations or software, where scale economies can be expected and controlled. Instead, in the world of electric utilities, scale advantages can be affected by factors such as the size/customer density, elevation, and natural terrain of the service territory, T&D asset strategy adopted by the owner across the asset classes (e.g. "Run to Fail" or "Proactive Renewal"), customer mix, resource availability and exposure, and many others. As my previous answers suggest, it is simply incorrect to state, as Mr. Kollen does, that Kentucky Power's departure from AEP to join another utility company with 30 other subsidiaries will result in lost efficiencies just because this company is smaller in size than AEP.

III. <u>MR. KOLLEN'S ANALYSIS OF THE PURPORTED DISTRIBUTION SYSTEM UNDER-INVESTMENT SHOWS A NUMBER OF FUNDAMENTAL FLAWS.</u>

Q. ARE THERE OTHER AREAS OF MR. KOLLEN'S TESTIMONY THAT OVERSIMPLIFY WHAT ARE MUCH MORE COMPLEX AND NUANCED OPERATING AND CAPITAL DYNAMICS?

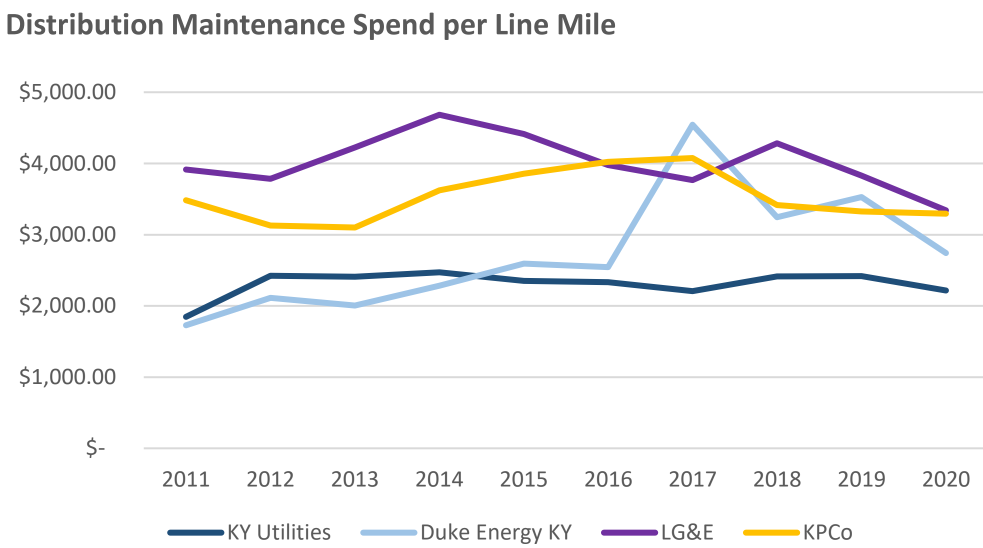
A. There are. One such area is Mr. Kollen's comparison of Kentucky Power's distribution maintenance costs per customer over the past decade with those of the other IOUs in the state – namely Louisville Gas and Electric (LG&E), Kentucky Utilities Company and Duke Energy Kentucky Inc. By unitizing the four distribution maintenance costs over the number of customers and deriving a much higher unit cost for Kentucky Power relative to other three utilities, Mr. Kollen argues that the cost difference is a function of the company's underinvestment in capital. Liberty has challenged the simplicity of the underlying logic and its inconsistency with the core asset lifecycle management principles in our response to DR KIUC-02-29. However, Mr. Kollen appears to have dismissed it and proceeded further with his analysis.

Q. ARE THERE ISSUES WITH MR. KOLLEN'S CALCULATIONS OF MAINTENANCE COST PER CUSTOMER?

A. There are no issues with calculations themselves, but there are serious issues with implications that Mr. Kollen attempts to assign to this one data point. First, customer count is only one of the drivers of distribution system costs, with others being peak demand, system line miles, service area size (and by extension, customer density, and others). If an additional customer chooses to connect to a system in a dense urban area, the resulting maintenance cost will be negligible. Whereas if the same customer decides to connect in a location that is several miles away and requires the system to be expanded (and patrolled, trimmed, etc. over the course of its lifecycle), maintenance costs will increase. This is why cost per customer alone does not tell an accurate story of distribution system operation economics. Other, equally viable, and statistically verified cost drivers exist and should be considered when making distribution capital investment and maintenance analysis.

Q. DID MR. KOLLEN DISCLOSE THAT THERE MAY BE OTHER WAYS TO COMPARE MAINTENANCE UNIT COSTS THAT COULD HAVE DIFFERENT RESULTS THAT WOULD NEED TO BE INCORPORATED INTO THE OVERALL ANALYSIS?

A. No, he did not. I have, however, conducted this analysis for Distribution Maintenance costs per line mile and per square mile of service territory for the same four IOUs that Mr. Kollen uses in his comparison[10] and present the results below.



As the above figure suggests, Kentucky Power's distribution maintenance spend per line mile shows a different story than Mr. Kollen's per customer analysis. First, all four utilities' results are relatively closer together than in the cost per customer analysis. Secondly, Kentucky Power is by no means the worst performer or an outlier on this metric. Its costs are in line with other distribution system operators, and, as such, show no reasons to suggest that Kentucky Power has underinvested in its system as Mr. Kollen does. In fact, the downward trend observed since 2017 could be interpreted as suggesting the opposite of Mr. Kollen's simplistic account of capital-maintenance relationship is to be used as guidance.

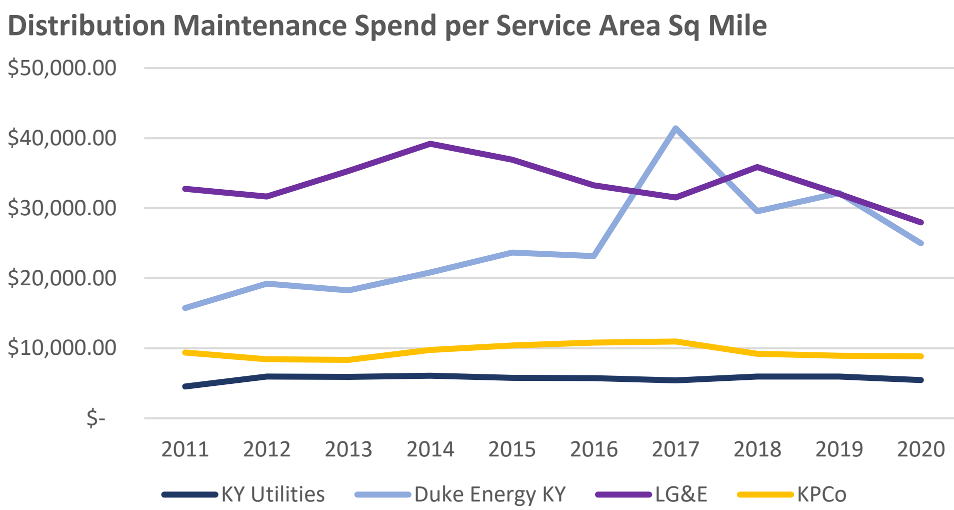
[10] Kollen Direct, p.51.

Q. WHY ARE LINE MILES AN IMPORTANT MAINTENANCE COST DRIVER FOR DISTRIBUTION UTILITIES?

A. Urban utilities tend to have much higher load density – that is more customers concentrated in a smaller geographic area, which requires fewer distribution lines, poles, and by extension, fewer line person and fleet and equipment hours to inspect, maintain, and rectify outages that occur in geographically concentrated areas. There is often a tradeoff in terms of capital investments (denser load areas typically have higher system capacity requirements, create more installation challenges given confined space, etc.), but in general, distribution maintenance expenses tend to be higher the more line length a utility has to service. Being a predominantly rural utility, Kentucky Power's system extends over significant lengths, interacts with more vegetation, and features relatively little underground lines. These factors that are a function of utility's service territory (rather than its management's choices) increase the overall distribution maintenance spend and make the "per line mile" unitization equally, if not more, valid than "per customer."

Q. WHAT ABOUT YOUR ANALYSIS OF MAINTENANCE COSTS PER SQUARE MILE?

A. As the figure below showcases, it paints a similar picture to the maintenance costs per line mile analysis. Kentucky Power is by no means the worst cost performer. In fact, using this metric that can be seen as a direct proxy of driving distance, maintenance of multiple service centers, feeder access difficulties over complex terrain, or vegetation / natural feature density, Kentucky Power has the second lowest maintenance cost per square mile of service territory.



Q. DOES THIS SUGGEST THAT KENTUCKY POWER IS ACTUALLY MORE EFFICIENT THAN OTHER UTILITIES IN TERMS OF ITS MAINTENANCE SPEND?

A. No more than Mr. Kollen's analysis of cost per customer suggests that Kentucky Power is overspending on maintenance due to capital underinvestment. All three dimensions of analysis (and potential other ones) are valid and represent important inputs that should be analyzed holistically through econometric analysis as regulators have done in the UK, Canada, and Australia. It is, however, completely inappropriate and disingenuous to pick just one metric that suits one's narrative as Mr. Kollen has done in his testimony.

Q. WHAT SHOULD THE COMMISSION FIND ABOUT MR. KOLLEN'S ARGUMENT THAT KENTUCKY POWER'S HIGH DISTRIBUTION MAINTENANCE COST PER CUSTOMER IS EVIDENCE OF PAST CAPITAL UNDERINVESTMENT AND A REASON FOR AEP TO PAY MORE THAN $354 MILLION IN COMPENSATION?

A. The Commission should dismiss Mr. Kollen's argument from further consideration as it is based on highly selective analysis of data that is indicative of a deliberate framing of data to suit one's purpose.

Q. WHAT ABOUT MR. KOLLEN'S COMPARATIVE ANALYSIS OF KENTUCKY POWER'S RELIABILITY RELATIVE TO THAT OF OTHER UTILITIES IN THE STATE?[11] SURELY THAT EVIDENCE IS SUGGESTIVE OF PAST CAPITAL UNDERINVESTMENT?

A. Not necessarily, and most certainly not to the magnitude illustrated by Mr. Kollen's analysis. Not all outages are caused by deficiencies in equipment state of wear/tear and repair. Plenty of outages that Mr. Kollen's analysis includes would not be preventable through capital investment unless the lines were buried (usually at least 6-8 times of capital cost of overhead infrastructure). In his analysis, Mr. Kollen compares the "rolled up" system average statistics that include outages that occur for all possible causes. Most, if not all, North American utilities have a standardized system of "outage cause codes" that they use to assign to each outage during the investigation and restoration process. The cause code information records help planners conduct subsequent reliability analysis to define or prioritize the capital or maintenance work locations and magnitudes. Among the typical cause codes are such as:

- Planned Outage;
- Vegetation Contact;
- Defective Equipment / Equipment Malfunction;

[11] Kollen Direct, pp. 49-50.

- Lighting Strike;
- Animal Contact;
- Motor Vehicle Accident;
- Adverse Weather;
- Third-Party Damage (e.g. a dig-in);
- System Operator Error;
- Vandalism.

The exact definitions and lists vary across utilities. However, as the above list hopefully illustrates, not all outages can be prevented through capital investment. I understand that in Kentucky Power's service territory, vegetation issues are particularly problematic causes of outages given the vegetation density and its service territory coverage. Mr. Kollen makes no effort to acknowledge this important fact that would simply qualify his assessment and give it more credibility whether he has access to the underlying cause code data or not.

Q. BUT WASN'T MR. KOLLEN'S ARGUMENT THAT KENTUCKY POWER HAS UNDER-INVESTED IN CAPITAL RENEWAL ULTIMATELY GROUNDED IN LIBERTY'S OWN ANALYSIS OF RATIOS BETWEEN CAPITAL SPEND AND DEPRECIATION CONDUCTED DURING DUE DILIGENCE?

A. It was, and as discussed in response to KIUC-02-29 this was Liberty's working hypothesis based on limited time, data, and preliminary contextual understanding of Kentucky Power's operating and ratemaking circumstances. As discussed in the above-referenced Data Request response, the relationship between capital and maintenance expenditure planning is far more complex than what AG's question assumed, and subsequently Mr.

Kollen's analysis highlighted in his testimony. Utilities can and do defer capital work in favor of preventative maintenance that may prolong the existing (and often fully depreciated) assets' lifecycle by additional years. Alternatively, utilities may decide through asset management analysis that it is more economic for them and their customers from the lifecycle perspective to run certain assets to failure and replace them only after they are no longer functional (particularly when doing so can result in limited or no outages). In this event, incurring an outage may be more economical than replacing the asset prematurely. Once again, there is a great degree of decision-making complexity underlying the capital-maintenance relationship that Mr. Kollen's analysis simply does not acknowledge.

Q. ARE THERE OTHER FACTORS THAT PUT INTO QUESTION THE CONCLUSIONS THAT MR. KOLLEN ATTEMPTS TO DRAW FROM HIS DISTRIBUTION CAPITAL-TO-MAINTENANCE RATIO ANALYSIS?

A. Yes. There are also the issues of Kentucky Power's rates and the need to balance distribution investments with other investment drivers. By focusing his analysis solely on distribution investments, Mr. Kollen conveniently forgets that Kentucky Power also has the generation fleet, transmission system, and intangible assets (plus vehicles, facilities, tools and implements, etc.) to sustain and improve as it sees necessary to address all issues with invariably less capital dollars. Whether it is due to concerns related to increases in Kentucky Power's rates or other matters, it is important to remember that Kentucky Power has a finite capital envelope, which it must distribute by making trade-off decisions across investments in diverse asset classes and categories. As such, isolating the distribution system investments the way Mr. Kollen does in his testimony creates a semblance of

Kentucky Power's investment decision-making being a lot simpler than it is in reality. It is for this reason that I once again suggest that the Commission dismiss Mr. Kollen's argument that the evidence he provided creates a rationale to demand a more than $354 million payout related to this issue from AEP.

Q. WHY IS A LIBERTY WITNESS DEFENDING KENTUCKY POWER/AEP ON AN ISSUE RELATED TO ITS PAST ACTIONS THAT PRECEDE LIBERTY'S INVOLVEMENT IN THE STATE?

A. I am not defending AEP or Kentucky Power. I am responding to Mr. Kollen's unreliable and highly self-serving analysis that ignores multiple technical factors and managerial considerations underlying utility planning and operation. It is especially troubling for me and for Liberty that this quality of analysis comes from an expert who claims that Liberty does not have sufficient technical expertise to operate Kentucky Power merely on account of requiring TSAs.

IV. LACK OF AFFILIATE AGREEMENTS IS NOT A SIGNAL OF INVENTORY AND SPARES SHARING EFFICIENCY LOSSES

Q. ARE YOU FAMILIAR WITH MR. KOLLEN'S ESTIMATE OF KENTUCKY POWER'S INCREASE IN CARRYING COSTS OF SPARES AND INVENTORY DUE TO SEPARATION FROM LIBERTY?

A. I am. Mr. Kollen estimates a 10-year NPV of cost increases driven by the additional inventories and spares financing costs of $13.9 million.

Q. WHY DO YOU THINK MR. KOLLEN IS PURSUING THIS PARTICULAR ISSUE AREA IN THE FIRST PLACE?

A. It is my understanding that he is due to Liberty's data request responses that it does not presently have an affiliate transactions agreement similar to AEP's for the sharing of materials and supplies.[12]

Q. DOES THE LACK OF SUCH AN AGREEMENT TODAY PREVENT LIBERTY FROM CONSIDERING ESTABLISHING SUCH AN AGREEMENT IN THE NEAR FUTURE SHOULD THERE BE AN ECONOMIC RATIONALE TO DO SO?

A. It does not. First, as Mr. Haynes testifies, the continued co-ownership of the Mitchell plant will continue to allow utilization of the existing spare agreements for that plant, to the degree necessary. In addition, Mr. Kollen ignores that Liberty is a company that owns 30 utilities in the United States and as such operates a robust supply chain management function to secure the best arrangements for customers. I am unsure why Mr. Kollen would ignore this fact or assume that the "standalone" Kentucky Power and its local supply chain / warehousing staff would operate in isolation from the rest of the organization once a part of the Liberty family.

Q. DO LIBERTY'S OTHER SUBSIDIARIES UTILIZE THE TYPES OF SPARE EQUIPMENT THAT MAY BE OF VALUE AT KENTUCKY POWER IN THE EVENT OF AN EMERGENCY OR AS A MEANS OF POTENTIALLY LEVERAGING GREATER PROCUREMENT ECONOMIES?

A. Yes, and chief among them is Empire Electric. Looking at long lead time station equipment, Empire Electric's spares fleet presently includes 36 station transformers and six portable station transformers with various nominal high and low voltage ratings, 119

[12] Kollen Direct, p. 33.

CF6 and vacuum circuit breakers, and five circuit switchers. In the event of an emergency, and subject to all legal and regulatory requirements being met, the necessary equipment could be shipped to Kentucky Power. In addition, and as noted in Liberty's response to Staff's KPSC-02-13, Liberty expects to continue participating in at least some of the industry spares sharing arrangements that Kentucky Power has been a member by way of its affiliation with AEP. Speaking of other commonly procured power system components, Liberty will have opportunities to explore supply chain efficiencies, and if these are available, I suspect that the lack of legal agreements would not be a significant impediment to rectify.

Q. HAS MR. KOLLEN INQUIRED ABOUT LIBERTY'S CURRENT SUPPLY CHAIN OR SPARES MANAGEMENT SET UP EARLIER IN THIS PROCEEDING?

A. Not beyond asking as to whether there was an existing affiliate agreement in place.

Q. CAN YOU TRACE MR. KOLLEN'S MATH IN ESTIMATING THE COST INCREASE DUE TO THE LOSS OF AEP'S SHARED INVENTORY AND SPARE PARTS AGREEMENT BACK TO THE COMPANY'S FINANCIALS?

A. I cannot. Mr. Kollen appears to have picked a "round" number of $25 million, and then by grossing it up, calculating the return and deriving the 10-year NPV of the resulting cashflows, arrives at an estimated number of $13.9 million.

Q. SHOULD THE COMMISSION TAKE THIS ESTIMATE INTO ACCOUNT WHEN CONTEMPLATING THE TOTAL VALUE OF THE PAYMENT THAT MESSRS. KOLLEN AND BARON ADVOCATE FOR AS A THRESHOLD FOR APPROVING THIS TRANSACTION?

A. No. For the reasons I mentioned above, this should not be considered.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. It does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF AMERICAN	)	
ELECTRIC POWER COMPANY, INC., KENTUCKY	)	
POWER COMPANY AND LIBERTY UTILITIES CO.	)	**CASE NO. 2021-00481**
FOR APPROVAL OF THE TRANSFER OF OWNERSHIP	)	
AND CONTROL OF KENTUCKY POWER COMPANY	)	

Exhibit DB-R1

DIMITRY BALASHOV

ON BEHALF OF

LIBERTY UTILITIES CO.

Witness OCS-2D

BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE JOINT NOTICE AND APPLICATION OF QUESTAR GAS COMPANY AND DOMINION RESOURCES, INC. OF PROPOSED MERGER OF QUESTAR CORPORATION AND DOMINION RESOURCES, INC.	))))))	**DOCKET NO. 16-057-01**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF CONSUMER SERVICES

CONTAINS REDACTED EXHIBIT SUBJECT TO RULE 746-100-16

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

JULY 7, 2016

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

<u>A. Qualifications</u>

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned both a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts in theology degree from Luther Rice University. I am a Certified Public Accountant, with a practice license, Certified Management Accountant, and Chartered Global Management Accountant. I am a member of several professional organizations.

I have been an active participant in the regulated utility industry for more than thirty years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in various positions in the areas of accounting, auditing, taxes, and planning.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on hundreds of occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified in dozens of utility merger and other restructuring proceedings, including mergers between electric and gas utility holding companies, as is the case in this proceeding. Most recently, I testified in the Southern Company/AGL Resources merger before the Georgia Public Service Commission ("GPSC") on behalf of the GPSC Staff. Most of these merger and restructuring proceedings have been resolved through settlement and the adoption of various conditions that ensure customers are protected from harm and timely benefit from opportunities, notably cost savings. My qualifications and regulatory appearances are further detailed in Exhibit___(LK-1).

Q. Who do you represent in this proceeding?

A. I represent the Utah Office of Consumer Services ("OCS").

B. Purpose

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Joint Notice and Application

("Application")of Questar Gas Company ("Questar Gas") and Dominion Resources, Inc. ("Dominion") (or together, "Applicants") for authorization of a transaction (the "transaction" or "Merger") whereby Dominion will acquire Questar Corporation, the parent company of Questar Gas and other affiliates, including Questar Pipeline Company ("Questar Pipeline") and Wexpro. The Applicants also seek an accounting order authorizing Questar Gas to defer "transition" costs incurred in connection with the Merger for subsequent recovery if deemed appropriate by the Utah Public Service Commission ("Commission").

C. Summary

Q. Please summarize your testimony.

A. I recommend that the Commission deny authorization for the proposed Merger unless it imposes necessary conditions. The proposed Merger does not meet the Commission's established merger standards, which protect customers and the public from harm and ensure that customers and the public timely receive benefits.

The proposed Merger imposes significant risks on customers and the public that are inadequately mitigated through the commitments offered by the Applicants and that are not offset with specific and quantified benefits through rate reductions and/or enhanced service quality. These risks include:

1. Risk of increased costs and customer rates with no certainty of offsetting savings or reductions in customer rates, including the costs due to affiliate agreements and increased credit risks.

2. Risk of diminished service quality and reliability.

3. Risk of liability from unrelated businesses and activities, including nuclear risk.

4. Risk of diminished local governance, decision-making, and autonomy.

5. Risk of diminished local access by regulators to decision-makers, regulatory personnel, books and records.

6. Risk of diminished local employment.

The Applicants have not identified and offer no tangible or quantifiable benefits to customers; the benefits asserted by the Applicants are generalized and incapable of quantification.

It is not in the public interest for the Commission to approve the merger, unless it imposes conditions that significantly expand upon the commitments offered by the Applicants. These conditions are necessary to mitigate the risks imposed on customers and the public, ensure that customers are protected from increased costs and diminished service quality, and ensure that customers benefit from timely reductions in rates and enhanced service quality requirements. The conditions also address local control, decision-making, and autonomy, as well as local staffing.

In the following sections of my testimony, I describe the proposed Merger; expand on the standards applied by the Commission in prior proceedings; describe in greater detail the risks imposed by the Merger on customers and the public; address the appropriate accounting and ratemaking for the purchase costs (goodwill, fair value in excess of net book value, other accounting changes, transaction costs), transition costs, and savings, including the deferred accounting for transition costs sought by Questar Gas; address various affiliate risks and costs, including costs incurred from Dominion Resources, Inc. Service Company ("Dominion Service"), Wexpro, and Questar Pipeline Company

("Questar Pipeline"); expand on the other risks and generalized benefits claims; and finally, propose modified or additional conditions that expand on the commitments offered by the Applicants, including a proposal to timely provide savings to customers. In addition to recommending conditions throughout my testimony, I list these modified and additional conditions in my Exhibit___(LK-2).

OCS witness Mr. Richard Baudino provides separate testimony wherein he addresses the credit quality and service quality risks imposed by the Merger and the conditions necessary to mitigate those risks if the Commission does not deny the Merger.

II. DESCRIPTION OF PROPOSED MERGER

A. Overview

Q. Please provide a description of the proposed Merger.

A. The proposed Merger is described in the Application, a PowerPoint presentation made in a technical conference held on April 28, 2016, and responses to discovery in this proceeding and the Wyoming proceedings. I have attached a copy of the PowerPoint presentation as my Exhibit___(LK-3).

Dominion Resources, Inc. and Questar Corporation entered into an Agreement and Plan of Merger ("Plan") dated January 31, 2016. The Plan was attached to the Application in this proceeding as Exhibit 1.1. On the date of closing, Questar Corporation will become Dominion Questar Corporation, a wholly owned subsidiary of Dominion that will continue to exist as a separate legal entity. On the date of closing, Questar Gas will become

Dominion Questar Gas, and will remain a direct wholly owned subsidiary of Dominion Questar Corporation.

After the closing, Dominion plans to contribute ("dropdown") all or part of the Questar Pipeline affiliate to Dominion Midstream Partners, L.P. ("Dominion Midstream"), a Master Limited Partnership ("MLP"), and divest certain Questar Pipeline assets. Dominion will not contribute the Wexpro affiliate to Dominion Midstream or to any MLP without Commission approval. [Leopold Direct Testimony at 15].

After the closing, Questar Gas will continue to receive certain shared or common services from Questar Corporation; however, in the future, all or some of these services will be provided by Dominion Service. Dominion has not identified or quantified any savings that may result from economies achieved through the proposed Merger.

After the closing, Dominion has no plans to change the organizational structure of Questar Gas or the Utah operations. Dominion has no plans to change the Questar Gas tariffs on file with the Commission, except to reflect the change in name to Dominion Questar Gas Company and other changes in the ordinary course of business. Questar Gas will continue to account for its costs in accordance with the Uniform System of Accounts and will maintain all financial books and records in Salt Lake City where they may be accessed in accordance with current practice.

After the closing, Questar Gas will continue to obtain natural gas from the Wexpro affiliate pursuant to Agreements approved by the Commission and pipeline transportation services from the Questar Pipeline Company affiliate pursuant to FERC tariffs.

Finally, the Applicants offer numerous commitments that they claim will provide benefits to Questar Gas customers and Utah. [Application at 25]. These commitments are categorized as Business, Employee Matters, Regulatory, Financial, and Community. [*Id.*, 25-30].

Q. Have the Applicants identified or quantified any specific savings from the proposed Merger?

A. No. The Applicants claim generally that there will be benefits to customers from Dominion's ownership of Questar Gas due to "greater financial strength and buying power, broader expertise in utility operations and business planning, and a shared focus on safety, reliability, customer service and efficiency of business operations over the long term." [Application at 14]. These benefits are described in generalized terms in the Application and by several of the Applicants' witnesses in their testimony; however, none of these claimed benefits are quantified, and no specific savings opportunities are identified or quantified. [Farrell Direct Testimony, Wood Direct Testimony, Leopold Direct Testimony]. Nor have the Applicants quantified any claimed benefits in response to discovery, including, but not limited to, the response to DPU 6.32. I have attached a copy of the response, along with all other responses cited in that response, as my Exhibit___(LK-4).

The Applicants also state that the proposed Merger "may result in lower costs to Dominion Questar Gas for these [shared or common] services over time." [Application at 12]. However, the Applicants have not yet determined synergies or cost savings that may result from the proposed merger. [*Id.*]. The Applicants have consistently maintained throughout this proceeding that they cannot identify or quantify specific savings opportunities at this time.

The only quantified benefit is the Applicants' offer to increase corporate contributions to charities within the Questar Gas local retail service territory by $1 million annually for at least five years. [Wagstaff Direct Testimony at 4]. However, this offer is independent of any savings that may be achieved through the integration process and does not provide customer benefits, although it may provide some other public interest benefit.

B. <u>Status of the Proposed Merger; Activities Before and After Closing</u>

Q. What is the status of the proposed Merger?

A. The Applicants plan to close the Merger by the end of this year. The Applicants have developed an integration framework and formed integration teams to address operations and shared services. The operations teams are structured to address the integration of Questar Corporation and the three major subsidiaries, Questar Gas, Questar Pipeline, and Wexpro into the Dominion structure and organization. There are seven shared services teams functionally focused on human resources, information technology and telecommunications, supply chain and facilities, regulatory/external affairs, finance and risk management, tax, and accounting. [PowerPoint presentation to Utah parties on April 28, 2016].

The Applicants are actively engaged in "Day 1" integration activities and identification of best practices and efficiency savings. Despite repeated discovery requests from several parties in this and the Wyoming proceedings, the Applicants provided no studies and no reports related to the planning or implementation of such integration activities until they recently provided copies of biweekly status reports in response to OCS 3.08. These status reports provide high-level summaries of the integration activities. I have attached a copy of the response to OCS 3.08 as my Confidential Exhibit___(LK-5).

Other than the high-level biweekly status reports, the Applicants' responses indicate that they are engaged in the "transition process" and have only made tentative decisions, if any, on significant issues, including, but not limited to, centralized services, staffing, employee benefits, accounting, and deferrals of transition costs and savings.

The Applicants are unable or unwilling at this time to quantify costs or savings resulting from the Merger and have offered no proposal to timely provide Questar Gas customers rate reductions to reflect expected or achieved savings. The Applicants state that the Questar Gas general rate case filing this month will be based on "projected costs absent any merger," according to the response to OCS 2.27, and that the filing will include no transition costs, according to the response to OCS 3.13. In other words, the pending Questar Gas general rate case filing does not reflect any costs or savings due to the Merger. Thus, the Applicants will retain all achieved savings until the next Questar Gas rate filing unless the Commission acts in this proceeding or in the pending rate case to ensure that customers receive timely rate reductions for expected or achieved savings. I have attached a copy of these responses as my Exhibit___(LK-6).

C. Investigations by OCS and Other Parties

Q. Please describe the investigations of the Merger by OCS and other parties.

A. OCS has been actively engaged in reviewing the transaction in this proceeding and has issued dozens of discovery requests. The Division of Public Utilities ("DPU") also has been very active in this docket and issued dozens of discovery requests. Similarly, the Wyoming Staff and Office of Consumer Advocate have been actively engaged in reviewing the transaction in Wyoming Docket Nos. 30010-150-GA-16 and 30025-1-GA-16 and have issued dozens of discovery requests. The OCS has reviewed all the discovery responses in this proceeding and in the Wyoming proceedings.

D. Commitments Offered by Applicants

Q. Please describe the "commitments" offered by the Applicants.

A. The Applicants have offered 30 "commitments," which are listed and described in their Application. [Application at 25-30]. Most of these "commitments" are 1) statements of intent or aspirational and not actually commitments, e.g., "Dominion intends to maintain Dominion Questar Gas' customer service at or better than current levels and will strive for continued improvements; 2) statements that recognize legal obligations, e.g., "Dominion and its subsidiaries will continue to honor the Wexpro Stipulation and Agreement, the Wexpro II Agreement or the conditions approved in connection with inclusion of properties in the Wexpro II Agreement; 3) restatements of their Application requests, e.g., "Dominion Questar Gas may defer transition costs associated with the Merger and will only seek recovery of such transition costs to the extent that it can demonstrate that such costs result in a net benefit to customers; and 4) commitments to maintain the status quo, e.g., "Dominion Questar Gas will continue to follow the Commission's Integrated Resource Plan process and guidelines." In addition, the Applicants have offered certain commitments that are consistent with commitments offered by the utilities or conditions imposed in other merger proceedings, e.g., "Dominion Questar Gas will maintain a complete set of books and records, including accounting records, for Dominion Questar Gas at its corporate office in Salt Lake City, Utah."

Q. Do the Applicants include any commitments that customers will not be harmed as the result of the Merger or any commitments to improve service quality or to ensure that achieved savings are flowed through to customers in a timely manner?

A. No. These are overarching concerns of the Commission, as evidenced in prior Commission decisions in other merger proceedings and as set forth in the various standards it has applied in those proceedings.

E. Request for an Accounting Order to Defer Transition Costs

Q. Please describe the Applicants' request for an accounting order to defer transition costs incurred by Questar Gas.

A. The Applicants request "an accounting order authorizing Questar Gas to defer for possible recovery in rates, if it elects to do so, the transition costs it incurs associated with the Merger." [Application at 36]. Despite the significance of this request, the only Applicant witness to address the request was Mr. Fred G. Wood, III. He addressed the request only to the extent that he listed it as a "commitment," stating that "Dominion Questar Gas may defer transition costs associated with the Merger and will only seek recovery of such transition costs to the extent that it can demonstrate that such costs result in a net benefit to customers." [Wood Direct Testimony at 15]. I would note that the proposal for an accounting order is a request; it does not qualify as a "commitment."

Q. Have the Applicants described the transition costs that will be deferred or how the deferrals will be recovered for ratemaking purposes?

A. No. The Applicants declined to provide a working definition of transition costs in response to OCS 2.12, although they described transition costs as "generally expenditures resulting from the preparation and implementation of activities necessary to integrate the purchased entity into the acquiring entity" in response to DPU 3.08. The Applicants declined to provide a description of any proposal to defer and track such costs for purposes of later recovery in response to OCS 2.13. Thus, there is no actual proposal for the deferrals other than the general request for an accounting order. I have attached copies of these responses as my Exhibit___(LK-7).

Q. Do the Applicants plan to reduce any such deferrals for savings achieved as a result of the Merger?

A. No. As I subsequently discuss, Questar does not plan to reduce any transition cost deferrals by the savings or to separately defer the savings. The Applicants stated in response to OCS 2.13 that any such savings would be reflected in rates in a future rate case. In other words, Questar Gas does not plan to timely flow through the savings to customers when they are achieved, but rather plans to retain such savings until a future rate case.

Q. The Applicants state that "Questar Gas will only seek recovery of such transition costs to the extent that it can demonstrate a net benefit to customers" in Mr. Woods' testimony. Have the Applicants provided a methodology for the calculation of the "net benefit"?

A. No. As I subsequently discuss, the Applicants have no specific proposal for the deferral of transition costs or the calculation of the "net benefit" to determine ratemaking recovery. In response to OCS 2.13, the Applicants stated that "The methodology for calculating the net benefit will be developed as part of the transition process."

III. THERE ARE SIGNIFICANT RISKS TO THE PUBLIC FROM THE PROPOSED MERGER

A. The Proposed Merger Imposes Significant Risks on the Public with No Known or Certain Offsetting Benefits

Q. Please summarize the risks imposed on the customers and public by the proposed Merger.

A. The proposed Merger imposes risks that may harm Questar Gas customers and the public. First and foremost, the Merger imposes the risk of increased costs that will affect the revenue requirement and the Questar Gas rates charged to customers. Second, the Merger imposes the risk of diminished service quality and reliability. Third, the Merger imposes the risk of liability from unrelated affiliate business activities, including nuclear risk exposure from Dominion's Virginia Electric and Power Company subsidiary. Fourth, the Merger imposes the risk of diminished local governance and autonomy and decision-making is removed from Salt Lake City to Richmond. Fifth, the Merger imposes the risk of diminished local access by regulators to decision-makers, regulatory personnel, and books and records. Sixth, the Merger imposes the risk of diminished local employment.

I address each of these risks, except for the service quality risk, in more detail in the subsequent sections of my testimony. Mr. Baudino addresses the increase in service quality risk and credit risk in his testimony.

B. Risk of Increased Costs and Customer Rates with No Certainty of Savings or Reductions in Customer Rates (Including Costs Associated with Increased Financing and Credit Risks)

Q. Please describe the risk of increased costs and customer rates.

A. There is a risk of increased costs incurred directly by Questar Gas and costs incurred indirectly by Questar Gas through affiliate transactions. The Applicants have not implemented an accounting process to track transaction and transition costs, according to the response to OCS 2.12. To the extent that transaction costs are misclassified as transition costs or not even identified as either transaction costs or transition costs, they may be included in the revenue requirement in either the rate case filed this month or in future rate case filings.

In addition, there is the risk of increased financing costs. These risks are addressed by Mr. Baudino, who proposes conditions to ensure that these costs are not imposed on Questar Gas customers.

Finally, there is the risk of increased costs through affiliate transactions. Initially, Questar Gas will be charged for shared or common services by both Questar Corporation, its present provider of these services, and Dominion Resources Services, which will provide some or all of these services in the future. There also is the risk of increased costs in charges for natural gas from Wexpro and for transportation services from Questar Pipeline.

C. Risk of Liability from Unrelated Businesses and Activities, Including Nuclear Risk

Q. Please describe the risk from unrelated businesses and activities, including nuclear risk.

A. Dominion is heavily engaged in non-regulated activities through numerous affiliates that have riskier business and financial profiles. Dominion also has nuclear risk through its Virginia Electric Power Company affiliate, which owns and operates four nuclear generating units.

D. Risk of Diminished Local Governance and Autonomy

Q. Please describe the risk of diminished local governance and authority.

A. Questar Corporation, Questar Gas, Questar Pipeline, and Wexpro are all Utah companies headquartered in Salt Lake City. They are autonomous and locally governed, which provides local access and accountability as well as local community involvement by executives and other employees. After the closing, they will become subsidiaries of Dominion and no longer will be locally governed.

E. Risk of Diminished Local Access by Regulators to Decision-Makers, Regulatory Personnel, Books and Records

Q. Please describe the risk of diminished local access by regulators to decision-makers, regulatory personnel, and books and records.

A. This risk is similar to that of the risk of diminished local governance and autonomy, but this risk is from the perspective of the Commission and its ability to provide oversight, set rates, and perform its other public service functions. This requires local access by regulators to decision-makers, regulatory personnel, and the books and records of Questar Gas as well as affiliates that charge costs to Questar Gas, including, but not limited to, Questar Corporation, Dominion Service, Wexpro, and Questar Pipeline.

F. Risk of Diminished Local Employment

Q. Please describe the risk of diminished local employment.

A. There likely will be reductions in local staffing resulting from the transfer of some or all of the shared or common services presently provided by Questar Corporation to Dominion Service. There will be a reduction in local employment if those positions are eliminated in Salt Lake City and consolidated in Richmond.

The reduction in local employment could be mitigated if, after the closing, certain shared or common services are provided to Dominion affiliates, including the former Questar Corporation affiliates, in Salt Lake City rather than in Richmond.

If local employment is reduced, it will negatively impact the local economy and will affect government tax receipts and likely increase government distributions to assist those who lose their jobs.

IV. THE PROPOSED MERGER DOES NOT MEET THE STANDARDS ESTABLISHED BY THE COMMISSION FOR THE APPROVAL OF MERGERS IN PRIOR PROCEEDINGS

A. The Commission's Standards Ensure that Customers and the Public Are Protected from Harm and Timely Receive Benefits

Q. In prior merger proceedings, what standards has the Commission applied?

A. I have reviewed the Commission's Orders in Docket No. 98-2035-04 (Scottish Power acquisition of PacifiCorp) and Docket No. 05-035-54 (MidAmerican acquisition of PacifiCorp). In those Orders, the Commission identified four standards that it applied to ensure that there was no harm imposed on customers and the public and to ensure that there were benefits to customers and the public resulting from the proposed mergers. The Commission referred to the no-harm standard, positive net benefits standard, public interest standard, and just and reasonable standard. I subsequently address each of these standards in greater detail and why conditions are necessary to meet these standards if the Commission does not deny the Merger.

Q. What standards do the Applicants believe apply in this proceeding?

A. It isn't clear that the Applicants believe any standards apply in this proceeding or that Commission approval is necessary. In the Application, they state: "To the extent the Commission believes approval of the Merger is required under Utah law, Questar Gas and Dominion hereby request an order of the Commission authorizing the Merger." [Application at 2].

In the Statement of Joint Applicants on Jurisdiction and Standard for Approval filed on March 10, 2016 in this proceeding, they state: "If the Commission believes approval of the Merger is required, the standard for approval is a finding that the Merger is in the public interest." In that Statement, the Applicants acknowledge that "In addition, the Commission has previously concluded that a merger transaction must provide a net positive benefit to the public to satisfy the public interest standard," although they do not address whether they believe that standard for approval applies in this proceeding or whether they oppose such a standard. In that Statement, the Applicants assert that the commitments they offer ensure that the Merger is in the public interest and that it provides positive net benefits.

B. The No-Harm Standard Protects Customers and the Public from Harm

Q. Please describe the no-harm standard and how the Commission applied it in the Scottish Power proceeding.

A. The no-harm standard is the very minimum standard that should be applied in this or any other merger proceeding. Overall, it is a lesser standard than the positive net benefits standard applied by the Commission in prior merger proceedings, still it is applicable on an overall basis as an overarching condition and to specific costs that may or will be affected by the Merger. The no harm requirement may be met through the structure of the proposed merger, commitments offered by the Applicants, and conditions to approval imposed by the Commission.

In the Scottish Power/PacifiCorp merger, the applicants cited a "no-harm standard" under Utah law, but agreed to accept the positive net benefits to customers standard (Scottish Power/PacifiCorp merger, Docket No. 98-2035-04 Order at 27). Many of the conditions adopted in that merger were to ensure that there was no harm to customers.

Q. Do the commitments offered by the Applicants ensure that there is no harm to customers?

A. No. The commitments do not ensure that costs or rates will not increase or that service quality will be maintained or improved. To the contrary, the risks imposed may result in increased costs and excessive rates to customers and diminished service quality. The increased costs may be incurred directly by Questar Gas through transaction or transition costs or indirectly through increases in affiliate charges, whether through transition costs or otherwise. Although the Applicants commit that they will not seek rate recovery of acquisition premium (goodwill) or transaction costs from Questar Gas customers, they have declined to provide a working definition of transaction costs in response to discovery, which I subsequently discuss in greater detail. The diminished service quality or reliability may occur in the absence of minimum service quality metrics and penalties for failure to achieve. Although the Applicants commit to maintaining or improving service quality, this commitment is aspirational, and does not ensure that there is no deterioration in service quality. Mr. Baudino addresses service quality in more detail.

Additional commitments are necessary to ensure that there is no harm to customers now or in the future from the proposed Merger.

Q. Should the Commission adopt an overarching condition that the merger result in no harm to customers regardless of the cause of the harm?

A. Yes. This is necessary because the Applicants have not agreed to indemnify or hold customers harmless from any increases in costs or rates due to the proposed Merger. The Commission should adopt the following overarching condition. In addition to this overarching condition, I recommend other conditions that address specific costs. Mr. Baudino recommends various conditions that address credit costs.

> The Applicants shall hold harmless Questar Gas customers from costs resulting from the Merger, regardless of whether the costs are incurred directly by Questar Gas or incurred indirectly through affiliate charges from Questar Corporation, Dominion Service, Questar Pipeline, or Wexpro.

C. The Positive Net Benefits Standard Ensures that Customers and the Public Timely Receive Benefits

Q. Please describe the positive net benefits standard and how the Commission applied it in the Scottish Power and MidAmerican proceedings.

A. The positive net benefits standard requires that there be benefits to customers, not only assurance that there will be no harm. The positive net benefits standard was set forth in the Scottish Power/PacifiCorp merger, Docket No. 98-2035-04 Order at 27, and reiterated in the MidAmerican/PacifiCorp merger, Docket No. 05-035-54 Order at 4). As with the no-harm standard, the positive net benefits requirement may be met through the structure of the proposed merger, commitments offered by the Applicants, and conditions to approval imposed by the Commission.

Q. Do the commitments offered by the Applicants provide positive net benefits to Questar Gas customers?

A. No. The positive net benefits standard expands the no-harm standard to require positive net benefits to customers. The commitments offered by the Applicants do not provide any specific and quantifiable positive net benefits to customers. The Applicants have not offered or made commitments to provide any potential benefits to customers through reductions in rates or to improve service quality.

Additional commitments are necessary to provide specific and quantifiable net benefits to customers. I address these commitments in greater detail to ensure that there are reductions in rates for achieved savings. Mr. Baudino addresses these commitments in greater detail to ensure that there is a continued focus on and improvements in service quality.

Q. Should the Commission adopt an overarching condition that the merger result in positive net benefits?

A. Yes. This is necessary because the Applicants have not agreed to provide any specific or quantifiable positive net benefits to customers, except for the proposed increase in charitable contributions which may have public interest benefit, but does not provide any benefit to customers. The Commission should adopt the following overarching condition. In addition, I recommend other conditions that address specific positive net benefits. Mr. Baudino recommends various conditions that address service quality.

> The Applicants shall provide positive net benefits to Questar Gas customers through specific and quantifiable net benefits, which include timely rate reductions to reflect achieved savings.

<u>D. The Public Interest and Just and Reasonable Standards Ensure that Customers, Employees, and the Public Are Protected from Harm and Timely Receive Benefits</u>

Q. Please describe the public interest standard and just and reasonable standards and how the Commission applied those standards in the Scottish Power proceeding.

A. The Commission cited the public interest standard and the just and reasonable standard in its Order approving the Scottish Power/PacifiCorp merger. [Docket No. 98-2035-04 Order at 27]. The Commission did not define those standards in that Order, but asserted that the conditions offered by the applicants and supplemented in the settlement in that proceeding ensured that the merger was in the public interest and was just and reasonable. The conditions in the settlement addressed customer, local access, employee, and other concerns that extended beyond costs, rates, and service quality.

In my experience, the public interest standard and just and reasonable standard require that there be no harm at a minimum and may require that there be positive net benefits, depending on the jurisdiction. In my experience, the public interest standard is quite broad and covers all risks imposed by the merger, while the just and reasonable standard is primarily applicable to the effects on costs and customer rates.

Q. Do the commitments offered by the Applicants ensure that the proposed Merger is in the public interest and just and reasonable?

A. No. First, the commitments offered by the Applicants do not ensure that there is no harm or that there are positive net benefits to customers. If those standards are not met, then the Merger cannot be in the public interest or just and reasonable.

Second, the commitments offered by the Applicants do not adequately address the risks of liability from unrelated businesses and activities, including nuclear risk; diminished local governance and autonomy; diminished local access by regulators to decision-makers, regulatory personnel, and books and records; diminished local employment; diminished local employee benefits.

Additional commitments are necessary to ring-fence Questar Gas from liabilities imposed by affiliates, ensure maintenance of local governance and autonomy, ensure local access, and ensure that local employment is not gutted or that local employee benefits are not modified to achieve savings that will be retained by Dominion.

<u>V. THE COMMISSION SHOULD DEFINE TERMS AND SPECIFY ACCOUNTING AND RATEMAKING FOR MERGER COSTS AND SAVINGS TO ENSURE THAT CUSTOMERS AND THE PUBLIC ARE PROTECTED FROM HARM AND TIMELY RECEIVE BENEFITS REGARDLESS OF WHETHER THE MERGER IS APPROVED OR NOT</u>

<u>A. Purchase Costs Should Not Be Recorded on Questar Gas Company's Accounting Books and Not Allowed Recovery in Rates from Customers</u>

Q. Please define the term "purchase costs."

A. Purchase costs include goodwill (acquisition premium), the excess of fair value over the net book value of the acquired company's assets, transaction costs, and transition costs that are not incurred to achieve savings.

Q. Please define the term "goodwill."

A. Goodwill is the excess of the purchase price over the fair value of the assets of the acquired company. The Applicants agree with this definition, according to their response to OCS 2.06. I have attached a copy of this response as my Exhibit___(LK-8).

These costs typically are recorded on the acquiring company's accounting books and on the acquired company's accounting books. In this case, the goodwill initially will be recorded on Questar Corporation's accounting books and will not be "pushed down" onto the accounting books of its subsidiaries, or more specifically, onto the accounting books of Questar Gas, Questar Pipeline, or Wexpro, according to the Applicants' response to OCS 2.06. However, when Questar Pipeline is contributed to Dominion Midstream, the goodwill for Questar Pipeline will be transferred from Questar Corporation to Dominion

Midstream, according to the response to OCS 2.06. It is not clear whether the goodwill for Questar Pipeline will be pushed down onto the accounting books of Questar Pipeline upon completion of the transfer.

Q. Have the Applicants committed to not seek recovery of the goodwill associated with the Merger from Questar Gas customers?

A. Yes. This is included in commitment "u" in the Application. [Application at 28]. In that commitment, the Applicants state that "Dominion Questar Gas will not seek recovery of any acquisition premium (goodwill) cost or transaction costs associated with the Merger from its customers. Dominion will not record any portion of the cost to acquire or any goodwill associated with the Merger on Dominion Questar Gas' books and is planning to make the required accounting entries associated with the Merger on that basis."

Q. Is commitment "u" sufficient to ensure that none of the goodwill is recovered from Questar Gas customers?

A. No. The commitment should be extended to ensure that none of the goodwill is recorded on the books of Questar Pipeline or Wexpro and that none of the goodwill is recovered from Questar Gas customers directly or indirectly through affiliate transactions, including the purchase of gas transportation services from Questar Pipeline or the purchase of gas from Wexpro pursuant to the Wexpro Agreements.

Q. Please define the term "fair value" and describe the accounting for "fair value" in excess of the net book value of the acquired company's assets.

A. Fair value is the excess of the market value over the net book value of the acquired company's assets. The Applicants agree with this definition, according to their response to OCS 2.08. I have attached a copy of this response as my Exhibit___(LK-9).

In an acquisition, the accounting rules require that the net book value of the acquired company's assets be written up to the fair or market value. This is accomplished through accounting entries on the acquired company's accounting books that debit (increase) the various assets and credit (increase) the additional paid in capital component of common equity.

In this case, the excess of the fair value over the net book value of the acquired company's assets initially will be recorded on Questar Corporation's accounting books and will not be "pushed down" onto the accounting books of its subsidiaries, or more specifically, onto the accounting books of Questar Gas, Questar Pipeline, or Wexpro, according to the Applicants' response to OCS 2.06, OCS 2.09, and WY 2.03. However, when Questar Pipeline is contributed to Dominion Midstream, the excess of the fair value over the net book value for Questar Pipeline will be transferred from Questar Corporation to Dominion Midstream, according to the response to OCS 2.06. It is not clear whether the fair value in excess of the net book value for Questar Pipeline will be pushed down onto the accounting books of Questar Pipeline.

Q. Is commitment "u" sufficient to ensure that none of the fair value in excess of net book value is recovered from Questar Gas customers?

A. No. The commitment should be extended to ensure that none of the fair value in excess of net book value is recorded on the books of Questar Pipeline or Wexpro and that none of the excess of fair value over net book value is recovered from Questar Gas customers directly or indirectly through affiliate transactions, including the purchase of gas transportation services from Questar Pipeline or the purchase of gas from Wexpro pursuant to the Wexpro Agreements.

Q. Are there any potential changes to the assets and liabilities recorded on the accounting books of Questar Corporation and its affiliates that may be required by the Merger?

A. Yes. Dominion may be required to restate the assets and liabilities of Questar Corporation, as well as the assets and liabilities of Questar Gas, Questar Pipeline, and Wexpro to conform to Dominion's accounting policies, according to the Applicants' responses to WY 1.23 and WY 2.03. I have attached a copy of these responses as my Exhibit___(LK-10).

Q. Is commitment "u" sufficient to ensure that none of these changes in the assets and liabilities on the accounting books of Questar Corporation, Questar Gas, Questar Pipeline, and Wexpro are reflected in Questar Gas' cost of service for ratemaking purposes?

A. No. Commitment "u" does not address this issue. Nor does any other commitment proposed by the Applicants address this issue. Consequently, the commitment should be extended to ensure that any accounting changes required to conform the Questar entities' accounting to Dominion's are not reflected in Questar Gas' cost of service for ratemaking purposes. The best way to do that is to ensure that the changes are recorded in subaccounts so that they can be readily excluded for ratemaking purposes.

Q. Please define the term "transaction costs."

A. Transaction costs are costs incurred in pursuing and executing the merger and typically include, but are not limited to, the following costs:

a. Legal, consulting, and other professional advisor costs to initiate, prepare, consummate, and implement the merger, including obtaining regulatory approvals, and compliance with regulatory conditions, although the response to OCS 2.24 indicates that Applicants do not agree that third party legal costs incurred in obtaining regulatory approvals are transaction costs.

b. Rebranding Questar Corporation, Questar Gas, Questar Pipeline, and Wexpro as affiliates of Dominion, including website, advertising, vehicles, signage, printing, stationery, etc., although the Applicants cite "signage" as a transition cost in the response to DPU 3.08.

d. Directors and Officers ("D&O") tail insurance.

e. Executive change in control (severance) costs, which the Applicants have quantified at approximately $15 million, according to the response to DPU 6.69.

f. Executive retention agreement costs.

g. Financing costs incurred to initially finance the merger, costs to subsequently refinance the merger, and increases in financing costs, including short term debt, long-term debt, and common equity due to increased credit risks caused by the merger.

h. Dominion Pipeline restructuring and refinancing costs.

The Applicants declined to provide a definition of transaction costs in response to OCS 2.10, although they generally described such costs in response to DPU 3.07 and provided examples in the responses to OCS 2.10, OCS 2.24, DPU 3.01, and DPU 3.07. I have attached a copy of these responses as my Exhibit___(LK-11).

Q. Have the Applicants committed to not seek recovery of the transaction costs associated with the Merger from Questar Gas customers?

A. Yes. This is included in commitment "u" in the Application. [Application at 28]. In that commitment, the Applicants state that "Dominion Questar Gas will not seek recovery of any acquisition premium (goodwill) cost or transaction costs associated with the Merger from its customers. Dominion will not record any portion of the cost to acquire or any goodwill associated with the Merger on Dominion Questar Gas' books and is planning to make the required accounting entries associated with the Merger on that basis." The Applicants reiterated their commitment that all transaction costs will be recorded at the holding companies and will not be pushed down to Questar affiliates in the responses to OCS 2.11 and WY 1.05. I have attached a copy of these responses as my Exhibit___(LK-12).

Q. Is commitment "u" sufficient to ensure that none of the transaction costs are recovered from Questar Gas customers?

A. No. The commitment should be extended to include a definition of transaction costs and a list of the known transaction costs. This is important because there is a distinction between transaction costs and transition costs for ratemaking purposes. The Applicants have committed that they will not seek recovery of transaction costs from Questar Gas customers, but they seek an accounting order for the deferral and potential recovery of transition costs, which could result in recovery up to the "net benefit" due to the Merger.

The commitment also should be extended to ensure that none of the transaction costs are recovered from Questar Gas customers directly or indirectly through affiliate transactions, including the purchase of gas transportation services from Questar Pipeline or the purchase of gas from Wexpro pursuant to the Wexpro Agreements.

B. Transition Costs That Are Not Incurred to Achieve Savings Are Properly Characterized as Transaction Costs and Should Be Recorded at Dominion or Questar Corporation and Not Allowed Recovery in Rates from Customers

Q. Please define the term "transition costs."

A. Transition (integration) costs are costs incurred to integrate the Questar Corporation and Dominion holding companies, Questar Corporation and Dominion Services shared or common services and activities, the Dominion and Questar utilities, and other affiliates. The costs include, but are not limited to:

a. Day 1 integration (capital expenditures and expenses).

b. Post Day 1 integration (capital expenditures and expenses).

c. Technology integration (capital expenditures and expenses).

d. Employee severance costs, except for executive change in control (golden parachutes).

e. Employee relocation/transfer costs.

f. All other capital expenditures and expenses incurred to implement the merger that are not defined as and included in Transaction costs.

The Applicants declined to provide a definition of transition costs in response to OCS 2.12, although they generally described such costs and provided examples in the response to DPU 3.08. The Applicants declined to identify all such transition costs or how they would be recorded by each entity in response to OCS 2.12. In addition, the Applicants have not quantified actual or projected transition costs, although they were asked to so, and have not separately accounted for actual transition costs incurred to date. Further, the Applicants plan to track transition costs for only 1 year after closing, according to the response to WY 2.13. I have attached a copy of the responses to OCS 2.12, DPU 3.08 and WY 2.13 as my Exhibit___(LK-13).

Q. Are there transition costs that are not incurred to achieve savings and other transition costs that are specifically incurred to achieve efficiencies and savings?

A. Yes. Transition costs can be subdivided into two categories:

a. Costs that are incurred to integrate/reorganize, but are *not* incurred to achieve savings. An example of transition costs that will not be incurred to achieve savings are the costs necessary to integrate hardware and software platforms used by the Questar entities into the platforms used by Dominion. The Applicants provided a list of planned IT integrations in response to OCS 2.23; however, the integration planning is not due to be completed until third quarter 2016; some systems will be "bridged" initially and then fully integrated in 2017.[1]

b. Costs incurred to integrate/reorganize that will achieve savings.

The distinction between these two categories of transition costs is important because transition costs that are not incurred to achieve savings are analogous to transaction costs. They are costs of the Merger, not costs incurred to achieve efficiencies or savings. If the Commission authorizes recovery of transition costs in any manner, whether through deferral and amortization or otherwise, then the transition costs that are not incurred to achieve savings should not be authorized for recovery.

Q. Does commitment "u" address transition costs that are not incurred to achieve savings?

A. No. There is no reference in commitment "u" to transition costs. The commitment should be extended to include transition costs that are not incurred to achieve savings and a list of the known transition costs that fall within that category.

[1] I have attached a copy of this response as my Exhibit___(LK-28).

Q. Please provide a revised commitment "u" that addresses all concerns with the "purchase costs," including goodwill, excess of fair value over net book value, transaction costs, changes to conform the accounting for assets and liabilities to Dominion's accounting, and transition costs that are not incurred to achieve savings.

A. I recommend that if the Commission does not deny the Merger, then it adopt the following revised commitment "u" as a condition of its approval.

> Dominion Questar Gas shall not seek recovery of any acquisition premium (goodwill) cost, excess of fair value over net book value, transaction cost, or transition cost that is not incurred to achieve savings due to the Merger from its customers. This includes costs incurred directly by Questar Gas and indirectly through charges from affiliates, including Questar Corporation, Dominion Service, Questar Pipeline, and Wexpro. Dominion Questar Gas shall not record any portion of the purchase costs, including goodwill and excess of fair value over net book value due to the Merger on its accounting books. Dominion Questar Gas shall not record any portion of the transaction costs or transition costs that are not incurred to achieve savings due to the Merger on its accounting books, or if it is required to do so by Generally Accepted Accounting Principles ("GAAP") or the Uniform System of Accounts, that it will do so in separately identifiable subaccounts.
>
> a. Transaction costs shall be defined as costs that are incurred in pursuing and executing the merger.
>
> b. Transaction costs shall include, but are not limited to:
> - Legal, consulting, and other professional advisor costs to initiate, prepare, consummate, and implement the Merger, including obtaining regulatory approvals, and compliance with regulatory conditions, although the response to OCS 2.24 indicates that Applicants do not agree that third party legal costs incurred in obtaining regulatory approvals are transaction costs.
> - Rebranding Questar Corporation, Questar Gas, Questar Pipeline, and Wexpro as affiliates of Dominion, including website, advertising, vehicles, signage, printing, stationery, etc., although the Applicants cite "signage" as a transition cost in the response to DPU 3.08.
> - Directors and Officers ("D&O") tail insurance.
> - Executive change in control (severance) costs, which the Applicants have quantified at approximately $15 million, according to the response to DPU 6.69.

- Executive retention agreement costs.
- Financing costs incurred to initially finance the merger, costs to subsequently refinance the Merger, and increases in financing costs, including short term debt, long-term debt, and common equity due to increased credit risks caused by the Merger.
- Dominion Pipeline restructuring and refinancing costs.

c. Transition costs shall be defined as costs incurred to integrate the Questar Corporation and Dominion holding companies, Questar Corporation and Dominion Service shared or common services and activities, the Dominion and Questar utilities, and other affiliates.

d. Transition costs that are not incurred to achieve savings shall include, but are not limited to:
   - Day 1 integration (capital expenditures and expenses).
   - Post Day 1 integration (capital expenditures and expenses).
   - Technology integration (capital expenditures and expenses).
   - Employee severance costs, except for executive change in control (golden parachutes).
   - Employee relocation/transfer costs.
   - All other capital expenditures and expenses incurred to implement the Merger that are not defined as and included in Transaction costs.

<u>C. No Transition Costs Should Be Deferred; The Applicants' Deferral Proposal Is Not Defined and Does Not Protect Customers Or Ensure That Customers Receive Timely Benefits</u>

Q. If the Commission approves the Merger, should it authorize Questar Gas to defer transition costs?

A. No. The Commission should direct the Applicants to expense all transition costs as incurred unless it timely flows through expected or achieved savings to customers through a reduction in rates. The Commission should not approve a proposal that the Applicants cannot or will not define. As I previously noted, the Applicants have not provided an actual proposal for deferral and recovery of transition costs, have not properly defined transition costs or provided a comprehensive list of such costs, and have not proposed a methodology for the calculation of Merger Savings.

If the Commission adopts the OCS recommendations to reduce rates 13 months after the closing and deny the request for accounting order, then the Company will have a behavioral incentive to minimize the transition costs and maximize the achieved savings, It will have to fund the transition costs that it incurs through the achieved savings in the 12 months after the closing.

Q. If the Commission does authorize deferral of transition costs, should it require that the deferrals be reduced by achieved savings if there is not a concomitant reduction in rates to reflect the savings?

A. Yes. I recommend that the Commission deny the request for an accounting order. As I subsequently discuss, I recommend that rates be reduced in the 13th month following the closing. However, the Applicants may achieve savings starting on Day 1 after closing and throughout the following 12 months. If customers are required to pay for transition costs as an offset to the savings flowed through to customers in future rates, then the deferred transition costs should be reduced by achieved savings prior to the reduction in rates.

Q. Do the Applicants agree that Merger Savings should be recorded as a reduction to the deferred transition costs if the Commission authorizes an accounting order?

A. No. The Applicants do not agree that Merger Savings should be recorded as an offset to the regulatory asset for deferred transition costs, according to the responses to OCS 2.13 and OCS 3.05. I have attached a copy of these responses as my Exhibit___(LK-14).

Q. If the Commission does authorize deferral of transition costs, should the Commission establish a condition that ensures that customers are not harmed and that they receive the benefits of expected or achieved savings?

A. Yes. If it does not deny the Merger and allows the deferral of transition costs, then the Commission should establish a condition that defines the transition costs that may be deferred and requires an offset for achieved savings not yet reflected in rate reductions to customers. The offset for achieved savings should commence immediately after the closing and continue until the savings are reflected in rates to customers.

I recommend that the Commission adopt the following condition.

> Questar Gas shall not be allowed to defer transition costs. If the Commission chooses to approve the request to defer transition costs, then Questar Gas shall be allowed to defer transition costs incurred to achieve savings, subject to reduction for achieved savings not yet reflected in rate reductions to customers. The calculation of achieved savings shall be consistent with the definition of Merger Savings used to calculate the rate reduction for such savings, i.e., the difference between the O&M/A&G expenses in the 12 months ending the month prior to the closing and the same expenses in the 12 months starting in the month after the closing on a ratemaking basis, adjusted to remove expenses for reserve accruals (bad debt, storm damage, etc.) and unusual, abnormal, and nonrecurring expenses. In no event shall negative savings be used to increase the deferred transition costs.

D. Net Merger Savings Should Be Timely Flowed through to Customers

Q. Please define Merger Savings.

A. Merger Savings are those reductions in operating expenses (operation and maintenance, or O&M, and administrative and general, or A&G, expenses) achieved as the result of the Merger through efficiencies and adoption of best practices.

Q. Can this definition be reduced to a formula?

A. Yes. Merger Savings can and should be objectively calculated pursuant to a simple formula. I recommend that the Commission calculate Merger Savings in the first year as the difference between the O&M/A&G expenses in the 12 months ending the month prior to the closing and the same expenses in the 12 months starting in the month after the closing on a ratemaking basis, adjusted to remove expenses for reserve accruals (bad debt, storm damage, etc.) and unusual, abnormal, and nonrecurring expenses. I recommend that the Commission calculate Merger Savings in each subsequent year using the same 12 months ending the month prior to closing, but update the subsequent 12 months starting the month immediately following the prior year calculation of savings. In no event shall this calculation result in negative savings or an increase in costs and used to increase the deferred transition costs or recover additional costs through the ratemaking process.

Q. Have the Applicants proposed a definition or methodology to calculate Merger Savings or quantified any savings?

A. No. The Applicants have identified no quantifiable savings from the merger, according to the responses to WY 1.21, OCS 2.13, and OCS 2.15. The Applicants have identified no specific plans (activities or timeline) and have prepared no analyses or studies that will "reduce administrative and operations and maintenance expenses incurred by Dominion Questar Gas, according to the response to DPU 6.32, even though such potential savings are cited as a benefit of the Merger. [Application at 31]. I have attached a copy of the responses to WY 1.21, OCS 2.15, and DPU 6.32 as my Exhibit___(LK-15).

The Applicants have identified potential areas of savings in response to DPU 4.17, although they have not quantified any savings. The Applicants claim that "Dominion did not study the mergers of other holding companies and/or utilities to identify and/or quantify transaction costs, transition costs and/or synergy savings," according to the response to OCS 2.20. Nevertheless, Dominion's experience in two prior acquisitions may provide some indication of the savings that may be achieved from this acquisition. The Applicants have provided pre- and post-merger O&M/A&G expenses for Dominion East Ohio and Dominion Hope, two LDCs previously acquired by Dominion in the response to DPU 4.25. The savings are very significant. In 1999, prior to its acquisition by Dominion, East Ohio incurred $270.077 million in non-gas O&M/A&G expenses. In 2001, the year after its acquisition by Dominion, Dominion East Ohio incurred $201.096 million in non-gas O&M/A&G expenses, a reduction of 26%. In 2002, the second year after the acquisition, Dominion East Ohio incurred $159.093 million in non-gas O&M/A&G expenses, a cumulative reduction of 41%.

In 1999, prior to its acquisition by Dominion, Hope incurred $42.806 million in non-gas O&M/A&G expenses. In 2001, the year after its acquisition by Dominion, Dominion Hope incurred $37.479 million in non-gas O&M/A&G expenses, a reduction of 12%. In 2002, the second year after the acquisition, Dominion Hope incurred $29.203 million in non-gas O&M/A&G expenses, a cumulative reduction of 32%.

I have attached the response to DPU 4.17 as my Exhibit___(LK-16) and the response to DPU 4.25 as my Exhibit___(LK-17).

Q. Have other utility mergers achieved significant cost savings?

A. Yes. Concentric Energy Advisors recently performed a study for Wisconsin Energy Corporation that quantified the actual savings from utility mergers. It quantified savings of 3%-5% of the O&M expense incurred prior to the merger compared to the O&M/A&G expense incurred after the merger. The results of this study were reflected in testimony by Mr. John Reed, the President of Concentric Energy Advisors, submitted in a recent Wisconsin Energy Corporation/Integrys merger proceeding before the Wisconsin Public Service Commission in Docket No. 9400-YO-100. I was an active participant and witness in that proceeding. I have attached a copy of the relevant pages from Mr. Reed's testimony as my Exhibit___(LK-18).

Q. What would the annual savings be if the experience of other utilities and Dominion are applied to Questar Gas?

A. Questar Gas incurred $162.5 million in non-gas O&M/A&G expense in 2015, according to its SEC 10-K filing. The annual savings would be $5 million to $8 million if the Concentric study range of 3% - 5% is applied. The annual savings would be $20 million to $67 million if the Dominion prior LDC acquisition savings range of 12% - 41% is applied. These annual savings do not reflect the amortization of any transition costs.

Q. Why is the Applicants' failure to provide a methodology or quantify the savings relevant to the denial or approval of the Merger?

A. It is relevant for numerous reasons. The first is that the calculation of Merger Savings is essential to providing customers a timely sharing of cost savings due to the Merger, an important issue under the positive net benefits standard. There will be no sharing of cost savings unless there is a methodology to calculate those savings.

The second reason is that the Applicants' future request to recover any authorized deferrals of transition costs depends on the calculation of the "net benefit," or the Net Merger Savings. Yet the Applicants have declined to provide a methodology or calculation for the "net benefit."

The third reason is that it is necessary to calculate the Merger Savings used to reduce the transition costs deferred if the Applicants' request for an accounting order is authorized and there is no immediate rate reduction.

The fourth reason is that it defers the calculation of Merger Savings to a future rate proceeding. In that future rate proceeding, the utility may propose that savings be calculated based on so-called avoided costs. That may be an extreme exercise in subjective analyses. For example, the utility may have increased staffing levels after the closing, but argue that it would have increased staffing levels even more but for the Merger. Of course, this is a subjective hypothesis and cannot be objectively tested.

The fifth reason is that the Applicants plan to track transition savings for only one year after closing, according to the response to WY 2.13. That plan does not resolve the issue of how the savings will be calculated or how they will be tracked, and does not address the Applicants' own proposal to recover transition costs to the extent there is a "net benefit."

Q. Is a timely reduction in rates an essential condition if the Commission does not deny authorization for the Merger?

A. Yes. The positive net benefits standard requires a timely reduction in rates, particularly given the risks of cost increases, diminished service quality, and the other risks imposed by the Merger.

Q. What is an appropriate condition to ensure that there is a timely reduction in rates for achieved cost savings?

A. I recommend that the Commission adopt the following condition, which includes the requirement to timely reduce rates and the methodology to determine the reduction in rates.

> Questar Gas shall timely reduce rates, either through a reduction in the base revenue requirement and rates or a surcredit rider, in the 13th month after the closing of the Merger and updated on the annual anniversary thereafter. The reduction shall be equal to the greater of $10 million or the Merger Savings less an amortization over 10 years of the transition costs incurred to achieve savings, reduced by the Merger Savings achieved prior to the rate reduction. Merger Savings shall be defined as the reduction in operating (O&M and A&G) expenses calculated as the difference between the 12 months ending the month before the closing to the 12 months starting the month after the closing and updated on the annual anniversary thereafter. All expenses shall be calculated on a ratemaking basis and exclude all transition costs and all abnormal and nonrecurring costs. The Applicant shall file a report showing the calculation of the Merger Savings and Transition costs, including all workpapers and electronic workpapers in live format with all formulas intact. The rate reduction shall go into effect, subject to adjustment after review and audit of the Merger Savings and Transition costs by the DPU.

VI. CHANGES IN CORPORATE RESTRUCTURE MAY HARM CUSTOMERS WHILE PROVIDING BENEFITS THAT DOMINION WILL RETAIN

Q. Please describe the organizational changes that Dominion plans and the potential effect on the costs charged to Questar Gas.

A. After the closing, Questar Gas will be a second tier subsidiary of Dominion and reported within the Dominion Energy segment. Dominion does not plan to contribute Questar Gas to Dominion Gas Holding ("DGH") even though the other Dominion gas utilities are owned by DGH and obtain all financing through DGH, according to the responses to DPU 2.12 and 2.13. Dominion does not plan to merge Questar Gas into any Dominion entity within the next 5 years, according to the response to WY 1.22. Dominion does not plan any changes in the Questar Gas organization chart, a copy of which was provided in the response to DPU 4.14. Dominion has no plans to transfer assets or contracts into or out of Questar Gas after the closing, according to the response to WY 1.20. I have attached the responses to DPU 2.12, DPU 2.13, DPU 4.14, WY 1.20, and WY 1.22 as my Exhibit___(LK-19).

After the closing, Dominion plans to contribute, or dropdown, Questar Pipeline to Dominion Midstream. Dominion Midstream is organized as an MLP, which means that it is a pass-through entity for income tax purposes and does not incur income tax expense. The MLP structure avoids the double taxation under the present Questar Pipeline structure as a traditional C corporation where it is taxed at the corporation level and the shareholders of Questar Corporation also are taxed on dividend distributions. The details of the dropdown of Questar Pipeline to Dominion Midstream have not been definitively determined at this point, according to the responses to DPU 6.18 and WY 2.03.1. The Applicants have not performed any analyses or studies to quantify the potential costs or benefits to customers from the contribution of all or part of Questar Pipeline to Dominion Midstream, according to the response to DPU 6.18. I have attached a copy of the response to OCS 3.03 as my Exhibit___(LK-22) and the response to DPU 6.18 and all the other responses cited in that response, including WY 2.03.1, as my Exhibit___(LK-20).

It is possible that the contribution will result in an increase in the common equity ratio at Questar Corporation and increase the shared or common costs allocated and charged to Questar Gas and Wexpro. It is possible that the equity ratio at Dominion Midstream or Questar Pipeline will increase and be used to calculate any FERC determined "cost-based" Questar Pipeline charges to Questar Gas. It is possible that the goodwill allocated to Questar Pipeline, but not initially recorded on its accounting books at the closing will be recorded on its accounting books after the contribution to Dominion Midstream, as I previously discussed. This may cause an increase in the wholesale transportation rates charged to Questar Gas. The Applicants assert that "Any decision regarding gas transmission rate treatment for any value above net book value for the contributed assets ('goodwill') would be made by FERC," according to the response to DPU 6.52. It also is possible that the contribution will be considered a tax sale; if so, the accumulated deferred income taxes ("ADIT") could or would be extinguished, potentially increasing any FERC determined wholesale cost-based rates and charges to Questar Gas, according to the response to DPU 6.52. I have attached a copy of the response to DPU 6.52 as my Exhibit___(LK-21).

In addition, Questar Pipeline no longer will incur income tax expense under the MLP structure, but Dominion claims that the FERC precedent nevertheless is to include an allowance for income tax expense in cost-based rates, according to the response to OCS 3.03. Despite all these potential changes to the Questar Corporation charges to Questar Gas and Wexpro and the Questar Pipeline charges to Questar Gas, the Applicants failed to provide any analyses or studies that quantified the potential costs or benefits to customers, according to the response to DPU 6.18. I have attached a copy of the response to OCS 3.03 as my Exhibit___(LK-22) and the response to DPU 6.18 as my Exhibit___(LK-20).

Further, Dominion plans to transfer some or all of the shared or common services presently performed by Questar Corporation for Questar Gas, Questar Pipeline and Wexpro to Dominion Service. However, the Applicants have not yet identified the services that will be transferred, when they will be transferred, the cost to transfer, the savings from the transfer, where the services will be provided (Salt Lake City or Richmond), or what effect the transfer will have on local employment, according to the response to DPU 6.40 and the other responses referenced in the response. The Applicants are unable or unwilling at this time to quantify costs or savings resulting from the Merger, according to the responses to DPU 2.09 and DPU 6.40. In addition, there are differences in the allocation methodologies between Questar Corporation compared to Dominion Service, according to the responses to WY 2.21 (comparison of Questar Corporation and Dominion Service allocation methodologies) and DPU 2.10 (general information regarding Dominion Service allocations). I have attached a copy of these responses as my Exhibit___(LK-23).

These shared or common services costs are charged to Questar directly and through affiliate charges indirectly from Questar Pipeline and Wexpro. The costs charged to Questar Pipeline are recovered from Questar Gas through FERC tariffs. The costs charged to Wexpro costs are recovered from Questar Gas through various agreements approved by the Commission.

During the transition period, and perhaps on an ongoing basis, both Questar Corporation and Dominion Service will charge shared or common costs to Questar Gas, Questar Pipeline, and Wexpro. Charges from the two service companies could increase costs to Questar Gas, at least until Dominion transfers all shared or common service functions to Dominion Services. The Applicants provided direct and allocated charges by account/function/activity for 2010, 2011, 2012, 2013, 2014, and 2015 in the responses to DPU 2.05, DPU 2.05U, and DPU 5.01. The Applicants provided the allocation methods in the responses to DPU 2.06, DPU 2.07, DPU 2.08, DPU 5.05, and DPU 5.05U. I have attached a copy of these responses as my Exhibit___(LK-24).

The Applicants have not yet drafted the Dominion Service agreements, according to the response to DPU 4.19, or offered any commitments that costs will not increase as the result of the Merger.

Finally, the Merger will result in changes in income tax expense for Questar Gas, Questar Pipeline, and Wexpro, all of which could affect the costs incurred by Questar Gas. Presently, Questar Corporation files a consolidated income tax return and the Questar Corporation income tax expense is allocated to Questar Gas and the other affiliates based on net tax (gross tax less credits), according to the responses to DPU 5.02, 5.03, 5.04. After the closing, the Questar entities will be included in the Dominion consolidated tax return, where their income tax expense will be determined pursuant to the Dominion Consolidated Federal Income Tax Allocation Agreement ("Dominion Tax Agreement"). This could result in an increase in income tax expense. I have attached a copy of the responses to DPU 5.02, DPU 5.03, and DPU 5.04 as my Exhibit___(LK-25).

Q. Have the Applicants proposed any commitments or conditions to either hold harmless customers from cost increases due to the affiliate restructurings and other changes or to timely provide savings to customers?

A. No. Consequently, I recommend that the Commission adopt the following conditions.

Questar Gas shall hold customers harmless from any increases in costs related to the affiliate restructurings due to the Merger, including, but not limited to, the

> provision of shared or common services by Dominion Service and Questar Corporation, the contribution of Questar Pipeline to Dominion Midstream, and the change in income tax expense due to the Dominion Consolidated Federal Income Tax Allocation Agreement compared to the present Questar Corporation tax allocation approach as described in response to OCS 2.42.
>
> Questar Gas shall hold customers harmless from any increases in costs related to the contribution of Questar Pipeline to Dominion Midstream and the extinguishment of any ADIT that existed prior to the transaction.
>
> Questar Pipeline shall reduce its wholesale tariff rates to Questar Gas to reflect a 25% sharing of the income tax expense reduction for a minimum of 10 years.

In addition, I recommend that the Commission adopt the conditions relating to affiliates and affiliate transactions that were adopted by the Commission in the Scottish Power/PacifiCorp merger proceeding. These included limitations on the types of transactions, approvals for certain transactions, reporting requirements, and access to books and records, among others (see Stipulation at 3-5).

VII. APPLICANTS' PROPOSED RING-FENCING COMMITMENTS ARE INADEQUATE

Q. Does the ring-fencing of Questar Gas as a separate non-recourse entity provide adequate liability protection if there is a significant event at Dominion or one of its subsidiaries, such as an accident at one of the nuclear generating units owned by VEPCO?

A. No. The ring-fencing commitments set forth in the Application regarding financing are necessary, but do not address the liability risk and potential costs that may be imposed on Questar Gas from another Dominion affiliate. Consequently, I recommend that the Commission adopt the following condition.

> Dominion shall indemnify Questar Corporation, Questar Pipeline, Questar Gas, and Wexpro from all liability incurred by any other Dominion subsidiary or affiliate now or at any time in the future.

VIII. APPLICANTS HAVE NOT DEFINED THE PROPOSED NEW WESTERN REGION HEADQUARTERS OR MADE ADEQUATE COMMITMENTS TO MAINTAIN LOCAL STAFFING LEVELS OR EMPLOYEE COMPENSATION AND BENEFITS

Q. Have the Applicants described the proposed new Western Region Headquarters, the activities or functions that it will perform, or the costs that it will incur or that may be charged to Questar Gas directly or through affiliate charges indirectly?

A. No. The Applicants stated that Questar Corporation headquarters in Salt Lake City will become Dominion's new Western Region headquarters. [Application at 25]; however, Applicants cannot or will not provide a more detailed description of functions or activities, timeline for development, estimated staffing levels, or costs, according to the responses to OCS 2.36, DPU 6.17. I have attached a copy of these responses as my Exhibit___(LK-26).

Q. Does this unknown constitute a potential risk to Questar Gas customers?

A. Yes. This unknown could result in increased costs to Questar Gas directly and through affiliate charges indirectly.

Q. Have the Applicants proposed any commitments or conditions to either hold harmless customers from cost increases due to this proposed new Western Region headquarters?

A. No. Consequently, I recommend that the Commission adopt the following condition.

Dominion shall hold Questar Gas customers harmless from any cost increases due to the proposed new Western Region headquarters.

Q. Have the Applicants provided any information, studies, or analyses or organizational and staffing changes at Questar Corporation that may result in reductions in local employment?

A. No. The Applicants claim that they do not know what organizational and staffing changes will be made at QC and that they have performed no studies or quantifications, according to the response to DPU 6.20. Applicants declined to estimate how many local employees will remain local after the closing and 5 years after the closing in the responses to DPU 6.45 and DPU 6.67. I have attached a copy of these responses as my Exhibit___(LK-27).

Q. To the extent that shared or common services are transferred from Questar Corporation to Dominion Services, should all related local staffing be transferred to Richmond?

A. No. To the extent that there are efficiencies and positions are eliminated, then the Applicants should make every attempt to maintain local staffing levels rather than eliminating all positions locally. This can be accomplished by prioritizing local employee staffing and retaining, transferring, or expanding certain shared services functions in Salt Lake City rather than transferring all functions to Richmond.

Q. Should the Commission address local staffing through a condition?

A. Yes. The Applicants offer commitment "j," which states: "Dominion will give employees of Dominion Questar and its subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Dominion organization, both inside and outside of Utah, to the extent any such employment positions are realigned, reduced or eliminated in the future as a result of the Merger." However, this commitment does not address or prioritize local employee staffing and retaining, transferring, or expanding certain shared services functions in Salt Lake City rather than transferring all functions to Richmond.

I recommend that the Commission adopt the following condition.

> Dominion shall not reduce local staffing headcounts by more than 25% from the present levels due to consolidation of Questar Corporation and Dominion Service shared or common service activities. Staffing increases due to the new Western Regional headquarters may be counted in local staffing headcounts. Dominion shall give consideration to the retention or transfer of certain shared or common services in Salt Lake City rather than moving or consolidating such functions in Richmond.

Q. Does this complete your testimony?

A. Yes.

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation

Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
as of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

**Expert Testimony Appearances
of
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as of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

**Expert Testimony Appearances
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as of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

**Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

Expert Testimony Appearances
of
Lane Kollen
as of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances
of
Lane Kollen
as of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
as of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.

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10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.

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11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.

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06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

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10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT -- bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/16 0/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

EXHIBIT ____ (LK-3)

Proposed Merger of Questar and Dominion
Utah Technical Conference
Docket No. 16-057-01
April 28, 2016

DOMINION AND QUESTAR—A COMMON REGULATORY PHILOSOPHY

Transparency

Collaboration

Open Communication

Local Management

WHY QUESTAR?

- ✓ **Compelling opportunity to combine premier regulated natural-gas asset profiles**

- ✓ **Complementary cultures with strong commitment to customers, communities and employees**

  —*Focus on doing business with integrity and honesty to promote safety and reliability*

- ✓ **Utah, Wyoming, and Idaho are highly attractive places to do business**

  —*Complements Dominion's existing regional presence (Utah solar investment)*

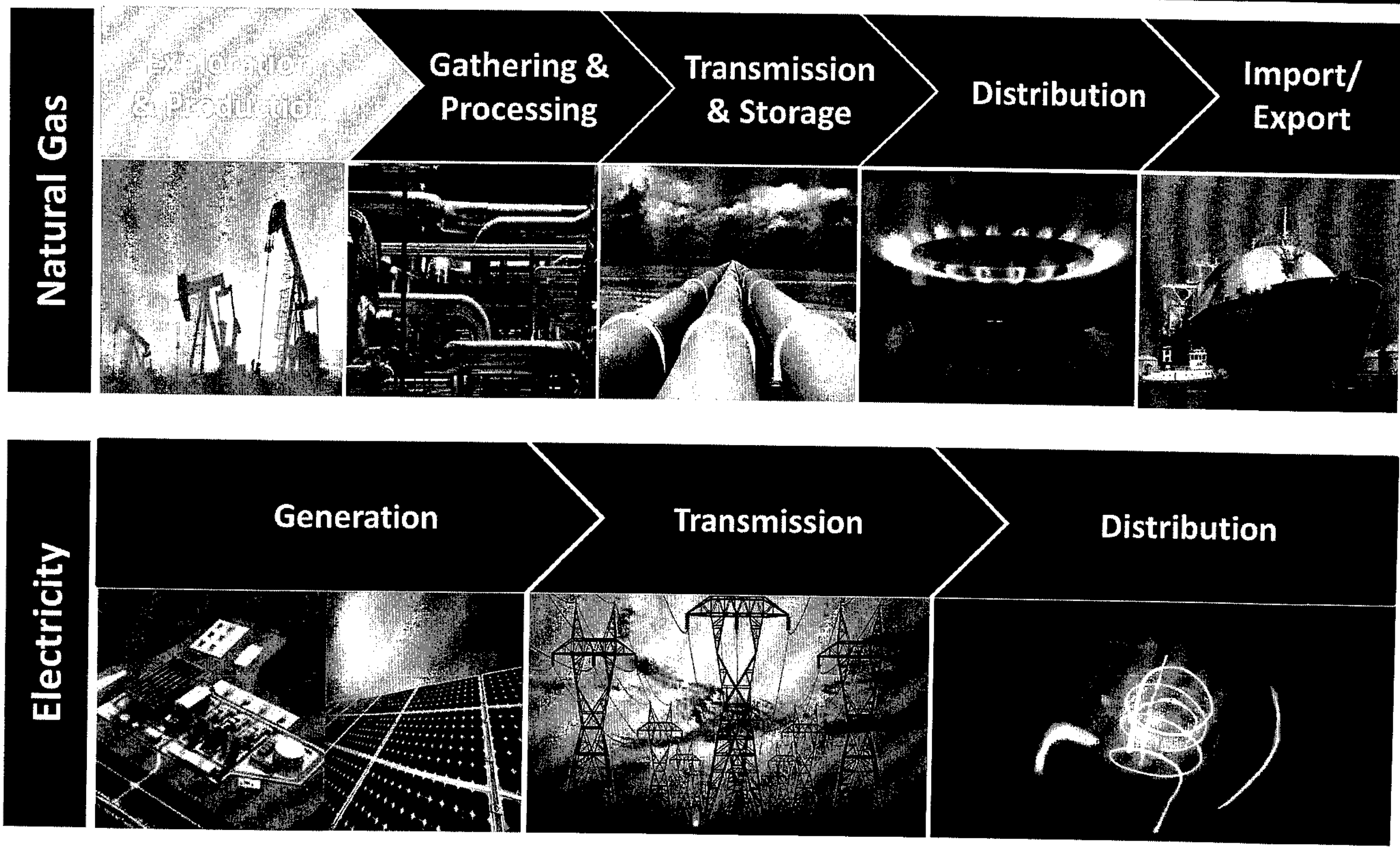
- ✓ **Well positioned to capitalize on increasing Western regional natural gas needs**

  —*Robust potential for long-term growth across all business units*

- ✓ **Additive to Dominion's portfolio of high-quality, MLP-eligible assets**

  —*Non-LDC assets are an ideal fit for Dominion's 100%-controlled and majority-owned Master Limited Partnership*

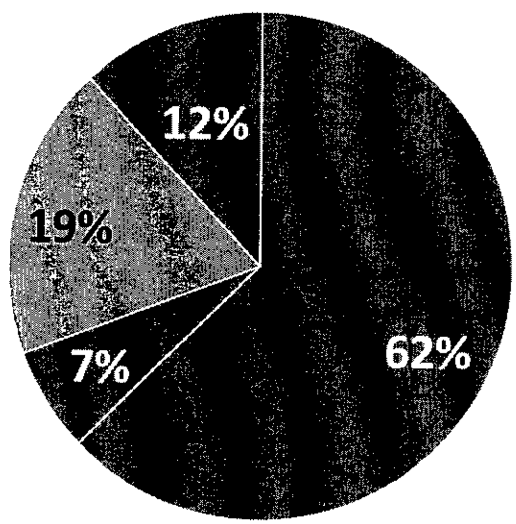
DOMINION'S OPERATIONS SPAN THE ENERGY VALUE CHAIN



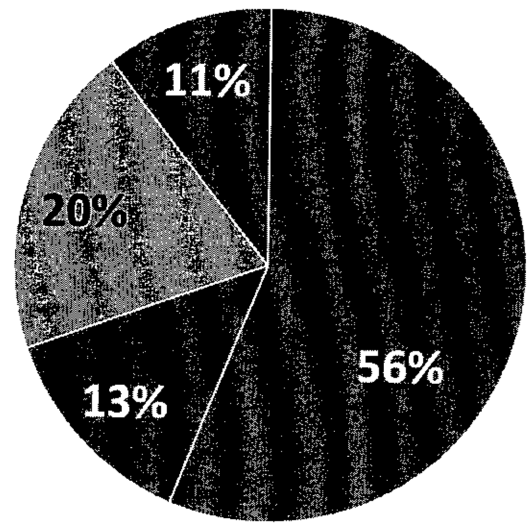
DOMINION'S PROFILE—A REGULATED FOCUS

EBITDA contribution (2015)

Dominion Resources



Dominion Resources with Questar



- State regulated electric
- State regulated gas[1]
- FERC regulated gas
- Other

[1] Wexpro included in state regulated gas segment

DOMINION PROFILE[1]

- **2015 Revenue: $11.7 billion**
- **2015 Operating earnings: $2.0 billion**
- **Total assets: $58.8 billion[2]**
- **Employees: 14,700**
- **Market capitalization: ~$42 billion[3]**

- **Energy infrastructure investment: ~$16 billion (2016E—2020E)**
  - —Gas: ~$6.0 billion
  - —Electric: More than $10 billion

[1] Does not include Questar
[2] As of 12/31/2015
[3] As of 4/27/2016

DOMINION'S OPERATING SEGMENTS

Dominion Energy

Gas Transmission

- Together with Gas Distribution, operates one of the largest natural gas storage system in the U.S.
- **12,200 miles** of pipeline in eight states
- Cove Point LNG facility
- Well positioned in Marcellus and Utica Shale regions

Gas Distribution

- **22,000 miles** of distribution pipeline and **1.3 million** franchise retail natural gas customer accounts in OH & WV

Dominion Virginia Power

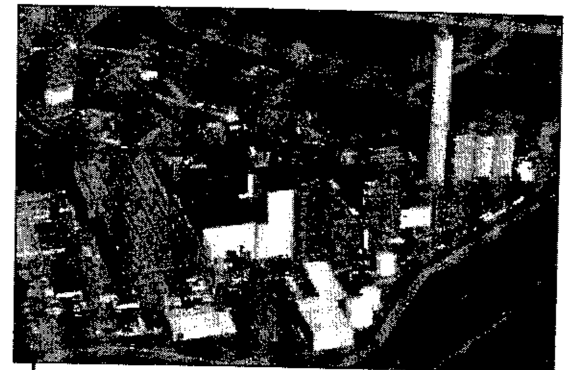
Electric Transmission

- **6,500 miles** of transmission lines
- Favorable regulatory environment

Electric Distribution

- **57,300 miles** of distribution lines
- **2.5 million** franchise retail customer accounts in VA and NC

Dominion Generation



Utility Generation

- **20,000 MW** of capacity
- Balanced, diverse fuel mix
- Favorable regulatory environment

Merchant Generation

- **4,300 MW** of capacity, including nuclear, gas and renewable power
- Active hedging program for energy revenue/margins

Exhibit DB-R1
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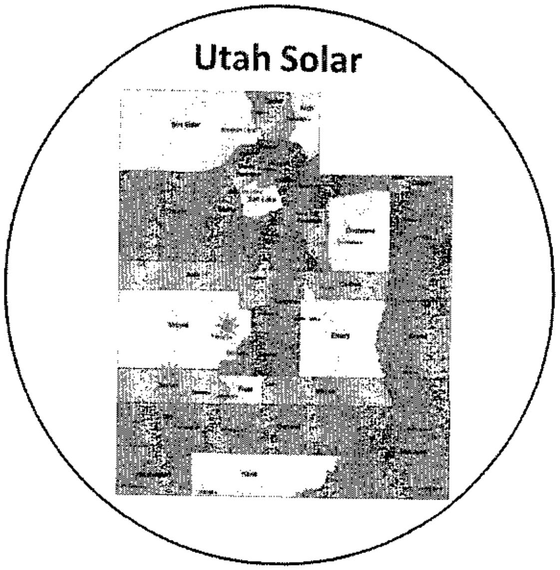
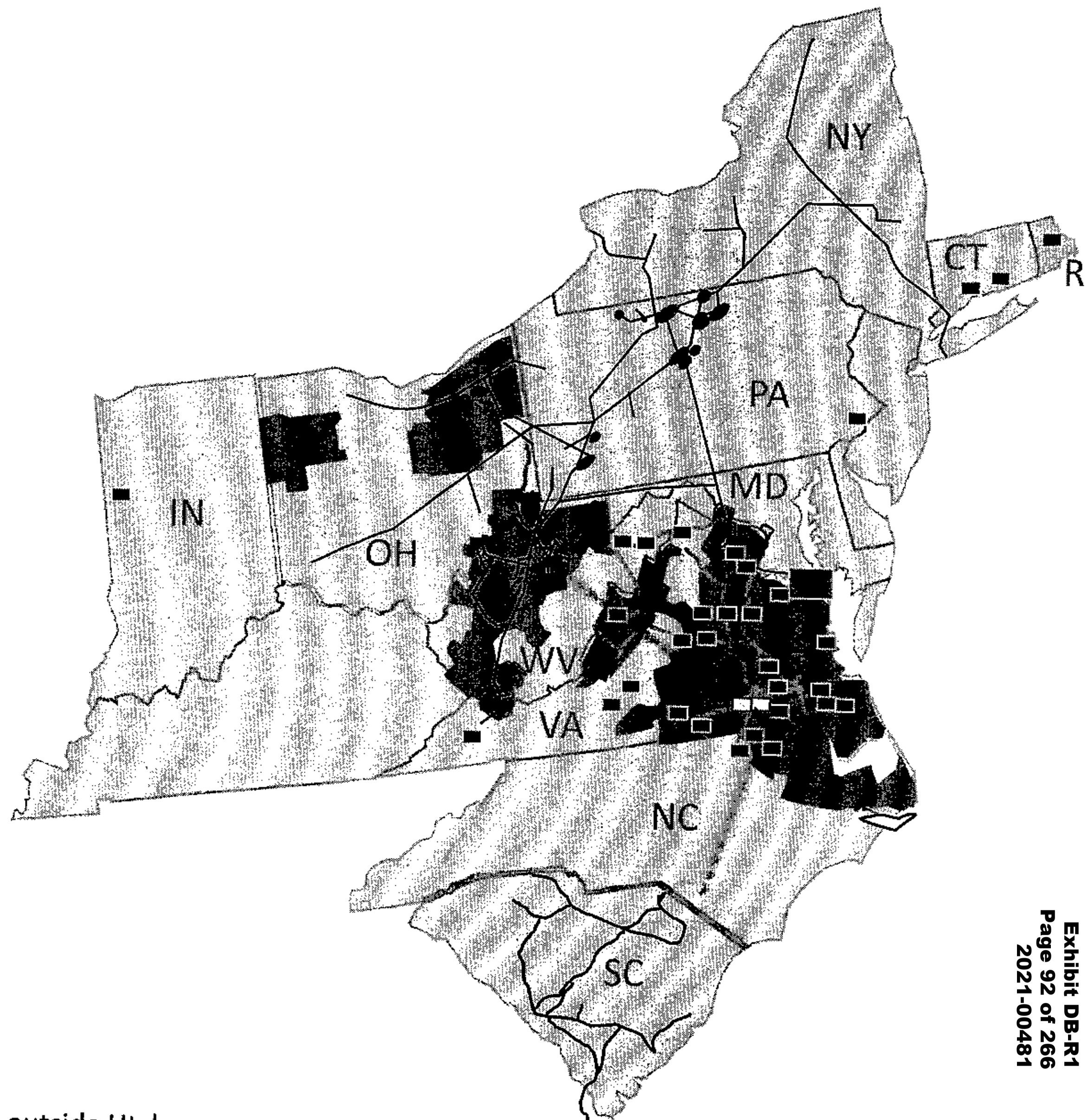
DOMINION FOOTPRINT





- Electric service territory
- Electric transmission system
- Electric generation facilities
- Generation under development
- Natural gas service territory
- Natural gas transmission, gathering and storage pipeline
- Natural gas storage operated
- Proposed Atlantic Coast Pipeline
- Cove Point LNG Facility

Note: Map does not include Dominion's solar facilities outside Utah

DECISION-MAKING LEVELS AND PROCESSES

Dominion Questar Gas will be managed from an operations standpoint as a separate regional business under Dominion

Dominion Corporate and Board decisions

- Proper corporate governance including final budget approval

Dominion Energy decisions

- Consistency across local operations to enhance organizational efficiency
- Safety and compliance program design
- Final budget review

Local operating decisions

- Budget development
- Safety and compliance program implementation
- Operations, system reliability, and customer service
- Regulatory and other stakeholder relations

MAINTAINING CUSTOMER SERVICE

Questar Gas' customers, communities and regulators will see benefits from a shared focus on safety, reliability, customer service and efficiency

Dominion and Questar Gas' common focus on customer service can be seen in their similar performance on key metrics

2015 Performance results

Customer service standard	DEO	QGC
Average speed of answer	34 seconds	29 seconds
Appointments met within 4-hour window	99.3%	97%
Gas service initiation within 5 days	100%	100%
Customer complaint resolution	1 day	3 days
Emergency call response within 60 minutes	98%	98%

COMMON CULTURE OF SHARING BEST PRACTICES

The combined company and its subsidiaries will benefit from the adoption of best practices across an expanded platform of service

Customer service

- Call center, billing, and advance metering technology
- Electronic bulletin board to confirm supply nominations

Pipeline operation

- Customer outage response
- Utilization of vacuum excavation technologies

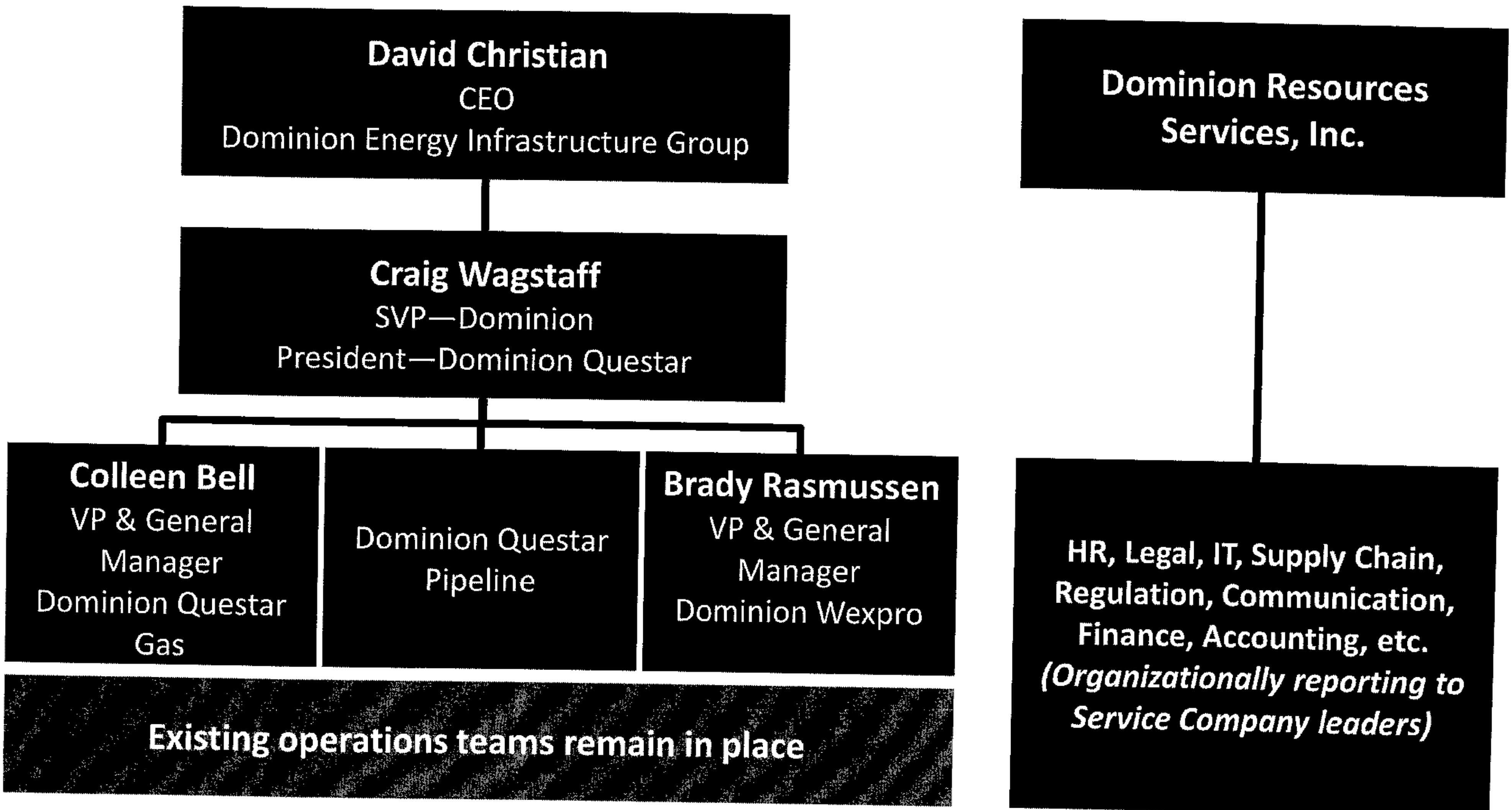
Engineering and construction

- Pipeline contractor diversity programs
- Asset data collection and GIS implementation

Employee safety and compliance

- Employee training in covered tasks
- Distribution/Transmission Integrity Management

POST-MERGER LEADERSHIP



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INTEGRATION FRAMEWORK

Groups of Dominion and Questar officers, senior managers, and other employees are aligned to plan, organize, coordinate, and execute organizational alignment

Questar
Ronald W. Jibson –
Chairman, President and CEO
Craig C. Wagstaff –
EVP and President, Questar Gas

Steering Committee

Executive Advisers
Integration Leads
Subject Matter Experts

Dominion
Thomas F. Farrell II –
Chairman, President and CEO
Carter M. Reid –
SVP, Chief Admin & Compliance Officer & Corp. Sec.
David Christian –
CEO Energy Infrastructure Group

Operations teams

Questar Corporation
- Questar Gas
- Questar Pipeline
- Wexpro

Shared services teams

- Human Resources
- Info Tech & Telecom
- Supply Chain & Facilities
- Regulatory / External affairs
- Finance / Risk Mgmt
- Tax
- Accounting

THE INTEGRATION PROCESS

A sequential and staged approach to design and execution

Integration efforts will occur thoughtfully to maintain consistent, safe, reliable, and cost-effective service

	Leadership & Framework Development	Analysis	Design	Implementation Planning	Implementation
Timing[1]	Feb to Apr	Apr to Jun	Jul to Aug	Aug to Close	Ongoing
Scope	Plan the Effort	Build the Facts	Define the Future	Prepare for Change	Close Transaction

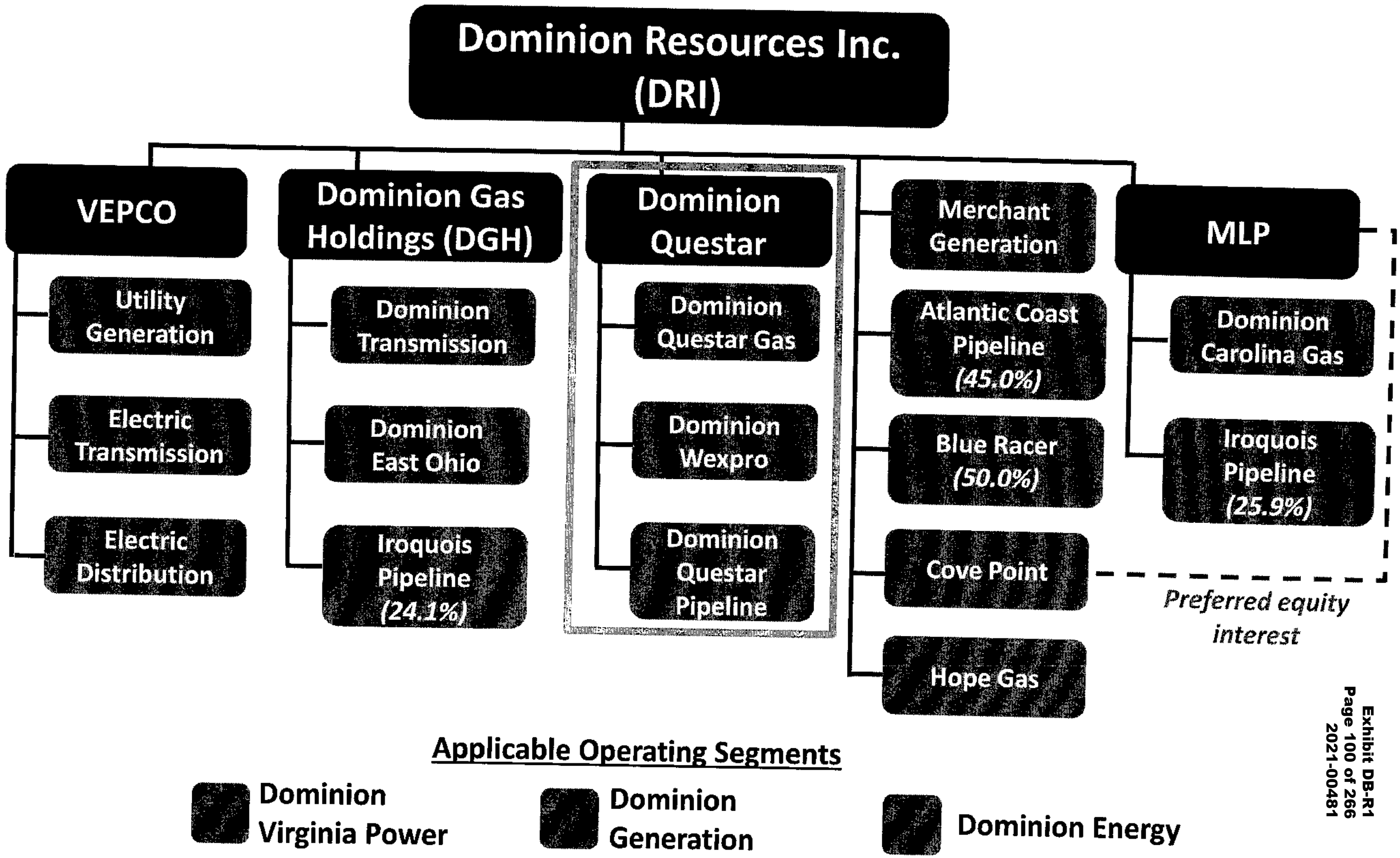
Key Stages

[1] Timing is approximate and stages will have some overlap

MERGER RELATED COSTS

- ✓ **Transaction costs**
  - –*Financial advisor and legal fees, goodwill, etc.*
  - –*Company will not seek cost recovery for transaction costs*
- ✓ **Transition costs**
  - –*Integration of systems, changes to duplicative costs, severance payments, etc.*
  - –*Proposed deferral of transition costs if net benefit can be shown*
- ✓ **All costs remain subject to prudency review during rate proceedings**

DOMINION'S PRO FORMA STRUCTURE



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HOW WILL DOMINION QUESTAR GAS BE FINANCED?

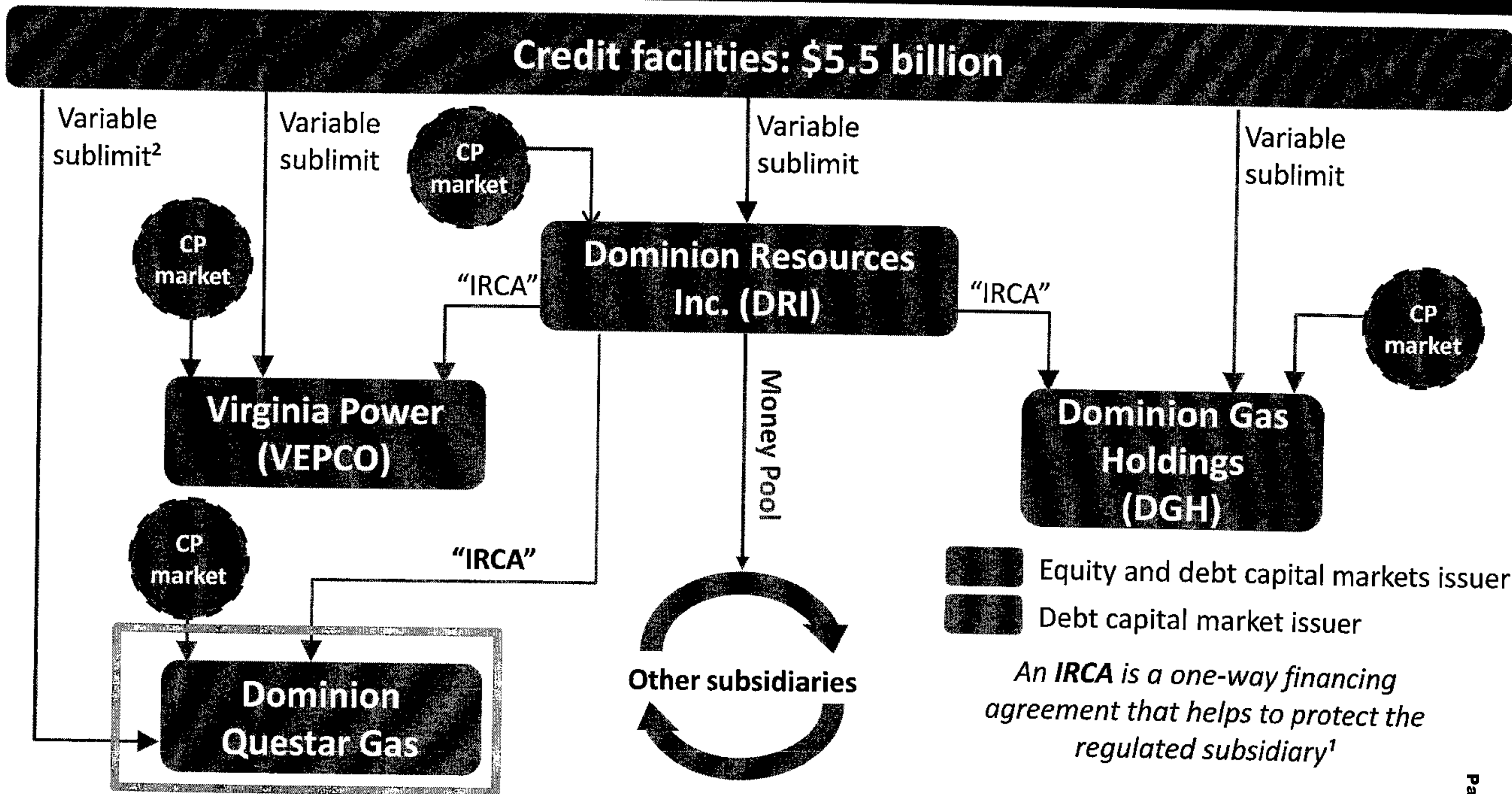


Exhibit DP-R1 Page 1 20

Dominion Questar Gas will have adequate short-term liquidity and the ability to access debt capital markets as a standalone issuer for long-term funding needs

[1] IRCA = Intercompany revolving credit agreement

[2] Addition of Questar Gas as a direct borrower to existing facilities requires lender consent; upon receipt CP program will be established

HOW WILL DOMINION QUESTAR GAS BE "RING-FENCED"?

- ✓ DRI and affiliates will not be able to borrow funds from Dominion Questar Gas ("IRCA")
- ✓ Maintain status as a standalone issuer of long-term debt
- ✓ Maintain current debt and equity capital ratios
- ✓ Maintain credit metrics that support strong investment-grade credit ratings
- ✓ Maintain issuer credit ratings from independent credit rating agencies
- ✓ Standalone audited financial statements (books and records maintained in SLC)
- ✓ Maintain as a separate and distinct legal entity
- ✓ Maintain Utah Commission oversight of Dominion Questar Gas dividends
- ✓ Appoint a member of Questar's Board of Directors to Dominion's Board of Directors

HOW WILL DOMINION FINANCE THE MERGER?

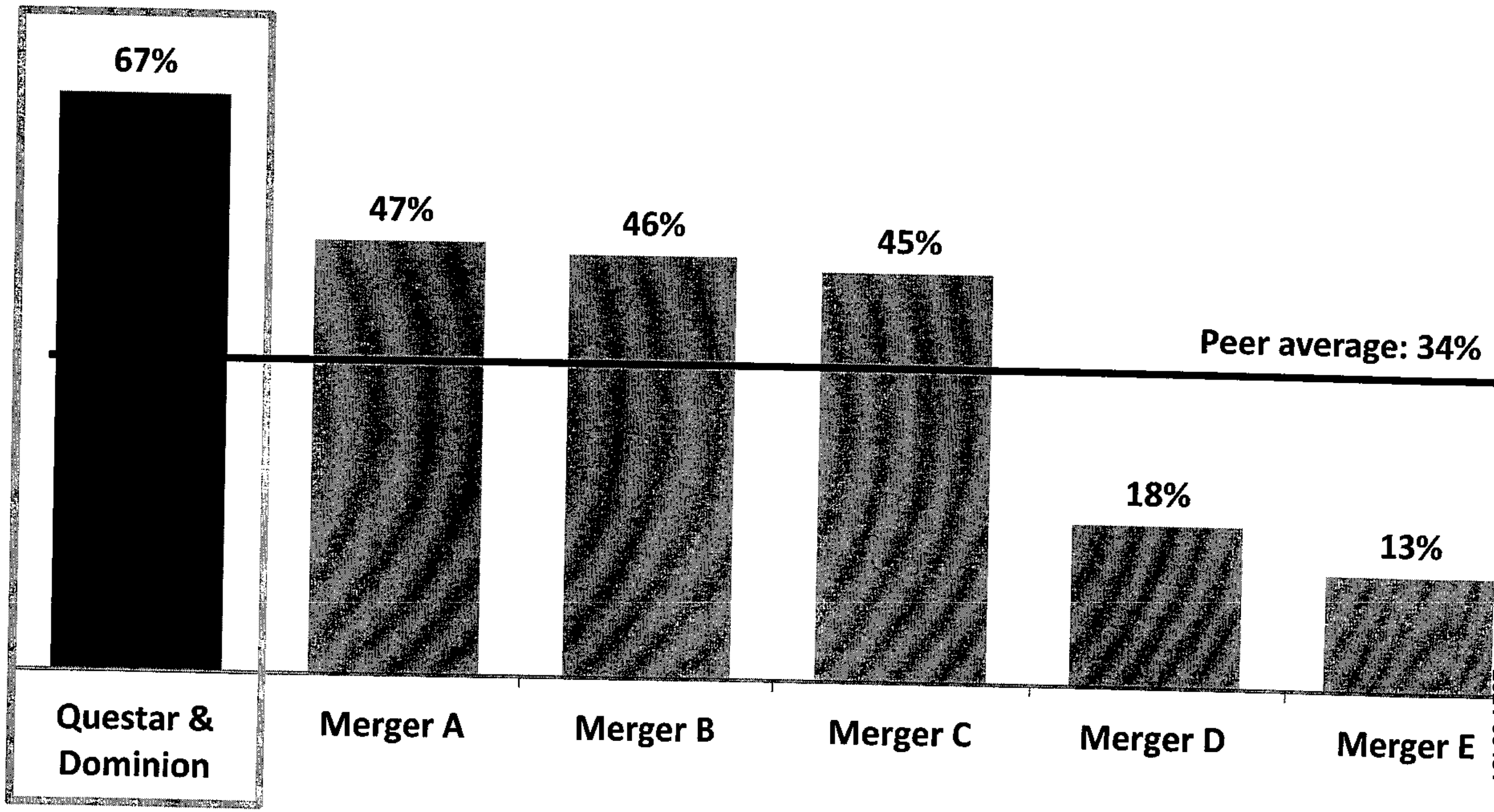
At Announcement	Prior to Closing	At Closing	Permanent Financing
Existing Credit Facility **$0.50**	DRI Senior Notes $1.45	DRI Senior Notes $1.45	DRI Senior Notes $1.45
Bridge Commitment **$2.70**	Mandatory Convertible *(converts to equity)* **$1.25**	Mandatory Convertible *(converts to equity)* **$1.25**	Mandatory Convertible *(converts to equity)* **$1.25**
	D equity (complete) **$0.50**	D Equity (complete) **$0.50**	D Equity (complete) **$0.50**
Term Loan Commitment **$1.20**	Term Loan Commitment **$1.20**	**Funded** Term Loan (364 day) **$1.20**	MLP Drop Proceeds (*Equity funded*) **$1.20**

Equity content of 67%

Note: All amounts in $ billion

HOW DOES DOMINION'S MERGER FINANCING COMPARE TO OTHER RECENT UTILITY MERGERS?

Percentage of merger consideration initially funded with equity/equity-linked securities



HOW DO THE CREDIT AGENCIES EVALUATE DOMINION AND QUESTAR GAS?

Agency	Methodology	Ratings[1]	
Moody's	Rating based on credit worthiness of **issuer**	A2	**Questar Gas (affirmed)**, VEPCO, DGH
		A3	—
		Baa1	—
		Baa2	DRI
Fitch	Rating based on credit worthiness of **issuer**	A	VEPCO
		A-	DGH
		BBB+	DRI
		Not rated	**Questar Gas**
S&P	**Issuer Rating**: Rating based on credit worthiness of **consolidated group**	A	**Questar Gas (current)**
		BBB+	**Questar Gas (expected)**, VEPCO, DGH
		BBB	DRI
	Anchor Rating: Rating based on credit worthiness of **issuer**	a	**Questar Gas (current and expected)**
		a-	DRI, VEPCO
		bbb	DGH

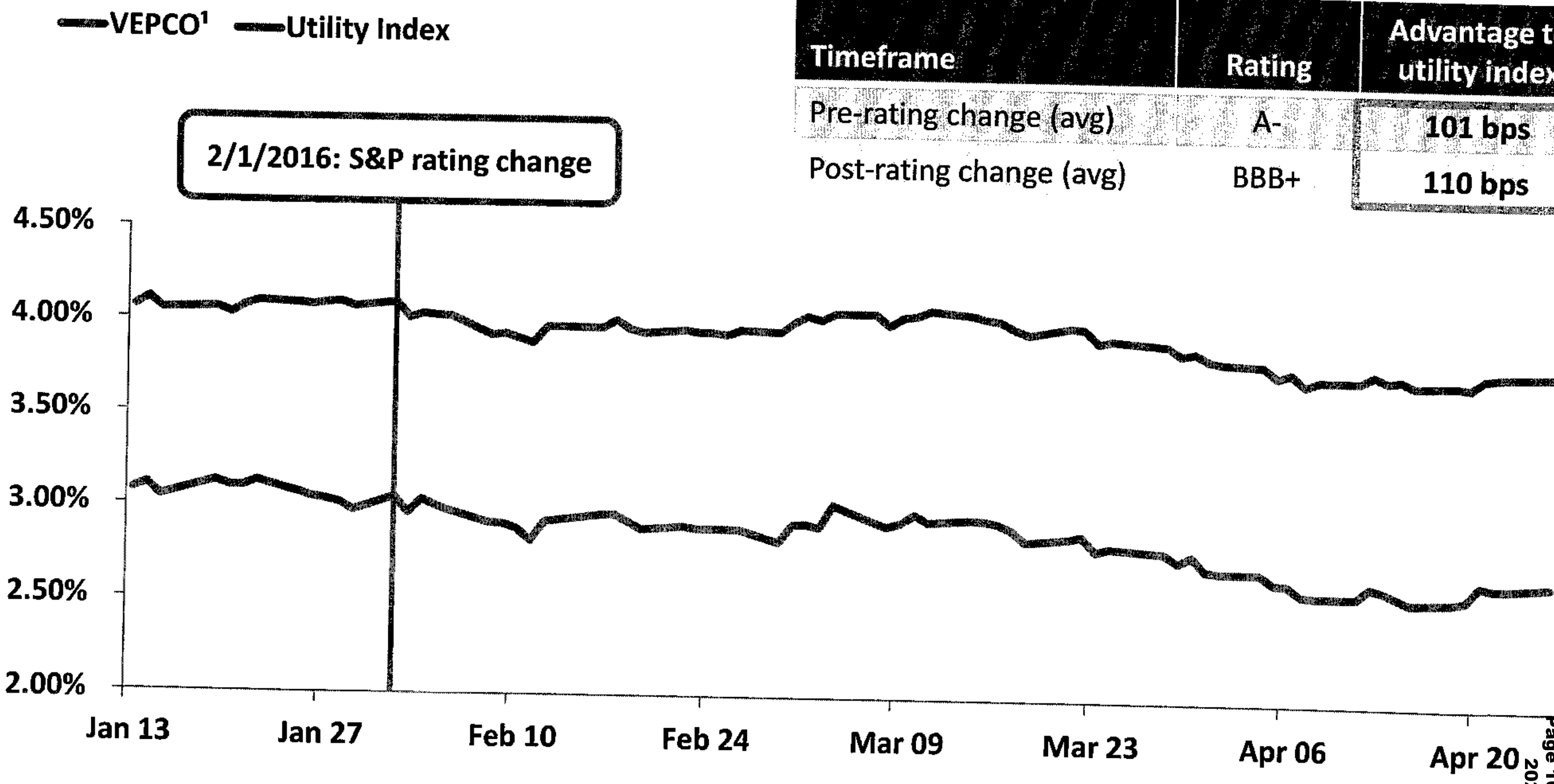
[1] Senior Unsecured ratings

Note: Dominion intends to solicit a Fitch rating for Questar Gas

QUESTAR AND DOMINION BORROWING COSTS IN CONTEXT

Impact of change in Dominion Resources' S&P consolidated rating

Timeframe	Rating	Advantage to utility index
Pre-rating change (avg)	A-	101 bps
Post-rating change (avg)	BBB+	110 bps



The change in rating at VEPCO (driven by S&P's strict consolidated family method) had a limited impact on VEPCO's absolute and relative debt yields

[1] VEPCO bond maturing in January 2026

QUESTAR AND DOMINION BORROWING COSTS IN CONTEXT

Recent (2013) regulated subsidiary long-term debt issuance

Issuer	Issuance date	Moody's rating[1]	S&P rating[1]	Issue size	Spread (bps)	Comparison to Q Gas
VEPCO	1/3/2013	A3	A-	$500M	+93.0	27 bps lower
VEPCO	8/12/2013	A3	A-	$585M	+95.0	25 bps lower
DGH	10/17/2013	A3	A-	$400M	+112.0	8 bps lower
Questar Gas	12/20/2013	A3	A	$90M	+120.0	—
Average						**20 bps lower**

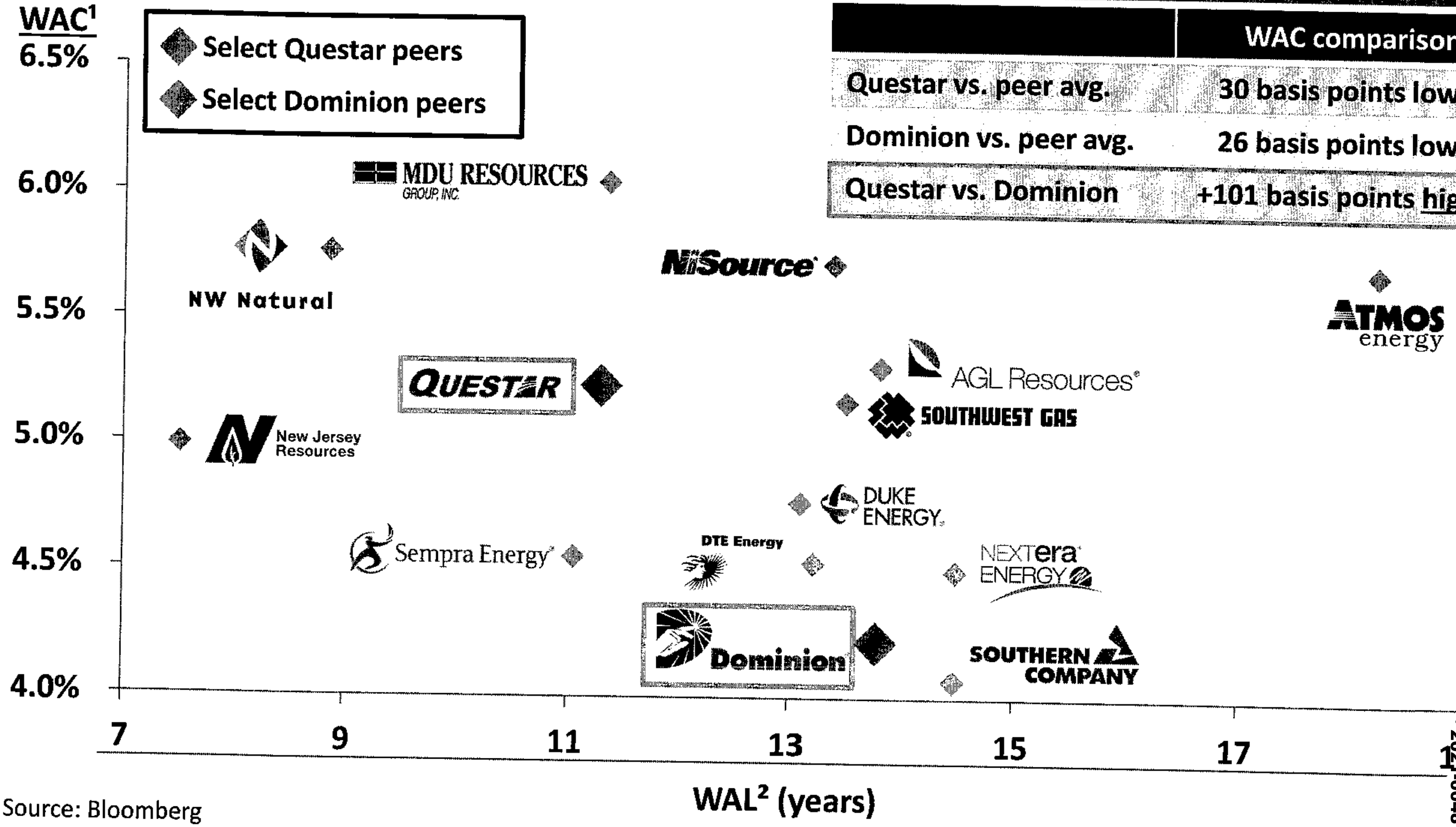
Dominion subsidiaries priced debt 20 basis points cheaper (on average) than Questar Gas despite identical Moody's ratings and lower S&P ratings

[1] Represent ratings at time of issuance in 2013

QUESTAR AND DOMINION BORROWING COSTS IN CONTEXT

Weighted-average cost of debt and weighted-average life of debt of select utility companies

	WAC comparison
Questar vs. peer avg.	30 basis points lower
Dominion vs. peer avg.	26 basis points lower
Questar vs. Dominion	+101 basis points higher



Source: Bloomberg

[1] Weighted-average cost of debt based on coupon of funded debt

[2] Weighted-average life of debt based on remaining duration of funded and unfunded debt

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COMMON FOCUS ON CUSTOMERS AND STAKEHOLDERS

Questar and Dominion are similar in their approach to formulating policies and plans in customer and stakeholder processes

Process	Questar	Dominion
Integrated Resource Planning	✓	✓
Energy efficiency collaboration	✓	✓
Gas hedging program	✓	✓
Infrastructure replacement programs	✓	✓
Other examples	Wexpro II	Off-shore Wind

DOMINION AND QUESTAR—A COMMON REGULATORY PHILOSOPHY

Transparency

Collaboration

Open Communication

Local Management

EXHIBIT ____ (LK-4)

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.32
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.32 Reference Joint Notice and Application ¶ 59g p. 31.

a. Please explain how Dominion plans to "reduce administrative and operations and maintenance expenses incurred by Dominion Questar Gas" and provide a timeline for the implementation of this plan.

b. Please explain if there has been any analysis or studies completed to quantify the potential costs and benefits to ratepayers due to Dominion's plans reduce administrative and operations and maintenance expenses incurred by Dominion Questar Gas.

c. If so, please provide all relevant documents including how costs and benefits to ratepayers in those areas were quantified.

d. If any costs will be incurred, please explain when these costs would be expected to show up in rates.

Answer: a.-d. See the testimony of Fred G. Wood, III at pages 10-11 in Joint Application Exhibit 6.0 and slide 14 of the Joint Applicants' presentations at the April 28th and 29th technical conferences in Utah and Wyoming respectively. See also the responses to DPU 4.01 and OCS 2.15.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-6)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.27
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Revenue Requirements

OCS 2.27 Please describe in detail how Dominion Questar Gas proposes to reflect any costs and synergy savings in future general rate cases.

Answer: The Company is planning to file its next general rate case in Utah on July 1, 2016. The forecasted test period in this rate case will be based on projected costs absent any merger. To the extent savings or synergy savings are identified in this docket, regulatory adjustments will be made to reflect these cost reductions, as appropriate. In future rate cases, any reductions in costs or synergy savings would be identified through the normal regulatory process.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.13
Requested by Office of Consumer Services
Date of QGC Response June 10, 2016

OCS 3.13 Refer to the response to OCS 2.27. Please indicate whether Questar Gas plans to remove all transition costs from its next general rate case filing in Utah. If so, please describe in detail its plans to identify and quantify these transition costs given that it cannot identify the costs or track them at this time, according to its response to OCS 2.12 and OCS 2.13.

Answer: The next general rate case will be filed in Utah on July 1, 2016. The base data to develop a test period in this case will be the actual revenue, expenses and rate base as of March 31, 2016. As indicated in OCS 3.09, Questar has incurred no transition costs to date, thus there will be no transition costs included in the next case. Any transition costs included in the following general rate case will only be included to the extent they are a part of the Commission approved deferred accounting asset.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

EXHIBIT ____ (LK-7)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.12
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.12 Please provide the Joint Applicants' working definition of transition costs and list each such cost that falls within this definition (the response to DPU 3.08 only provides examples and does not provide a comprehensive list). Explain why the Applicants believe each such cost should be considered a transition cost and not a transaction cost. In addition, describe the manner in which transition costs will be incurred and recorded by each relevant entity, including charges to and from other affiliates. Provide and describe the FERC accounts/subaccounts that will be used for these purposes and the costs that will be recorded in each such account/subaccount.

Answer: Dominion and Questar are currently in the transition process, in which the kinds of details of transition costs requested above are being developed. At this time, it is not possible to identify with specificity all transition costs beyond the examples that were provided in response to DPU 3.08. It is Dominion's and Questar's expectation that as we move through the transition process, the details of costs, how the costs fall into the "transition cost" category, accounting details (FERC account and sub accounts to which they may be charged) will be developed as part of the transition process.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.13
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.13 Refer to page 2 of the Application wherein it states, "Questar Gas requests the Commission to issue an accounting order authorizing it to defer transition costs incurred in connection with the merger, if it chooses to do so, for later recovery if deemed appropriate by the Commission." Refer also to similar language in the direct Testimony of Mr. Wood at page 15, lines 372-374.

a. Provide a detailed description of the Company's proposal to defer and track such costs for purposes of possible later recovery. Address both capital expenditures and expenses.

b. Identify and describe each "transition" cost contemplated for deferral.

c. Please confirm that synergy savings would be deferred as a regulatory liability or otherwise applied to reduce any costs deferred as a regulatory asset.

d. Refer to response to DPU 4.09 wherein the Applicants state that Questar Gas "will only seek recovery of such transition costs to the extent that it can demonstrate that such costs result in a net benefit to customers." Please provide the proposed methodology for the calculation of the "net benefit."

Answer: a. Please refer to response to OCS 2.12. The details around transition cost identification and deferral will be developed as part of the transition process.

b. Please see the responses to DPU 3.08 and OCS 2.12.

c. It is our expectation that any "synergy savings" would be flowed to customers through rates based on lower test year costs in a subsequent rate case. Such lower costs would have the effect of mitigating any transition costs deferred as a regulatory asset and pursuant to the merger commitments, no transition costs will be recoverable unless the company can demonstrate that such costs result in a net benefit to customers.

d. The methodology for calculating the net benefit will be developed as part of the transition process.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.08
Requested by Division of Public Utilities
Date of QGC Response April 15, 2016

DPU 3.08 The application indicates that the Dominion Questar may defer "transition" costs associated with the merger and may seek to recover these costs in the future. Please clarify and list the specific costs that would be considered transition costs.

Answer: Transition costs are generally expenditures resulting from the preparation and implementation of activities necessary to integrate the purchased entity into the acquiring entity. Examples of transition costs include but are not limited to the integration of financial, IT, human resource, billing, accounting, and telecommunications systems. Other costs could include severance payments to employees, changes to signage, and changes to employee benefit plans, costs to terminate any duplicative leases, contracts and operations, etc. The Company has asked the Commission for approval to create a deferred asset account to track transition costs.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

EXHIBIT ____ (LK-8)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.06
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.06 Please provide the Joint Applicants' working definitions of goodwill and acquisition premium and describe the manner in which goodwill and/or acquisition premium will be calculated and recorded for each relevant entity, including the FERC accounts/subaccounts that will be used for this purpose. If the two terms are not considered interchangeable, then please differentiate the terms and the costs that are considered goodwill versus the costs that are considered acquisition premium.

Answer: As defined in Accounting Standards Codification Topic 805, *Business Combinations*, goodwill is an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. The terms goodwill and acquisition premium are used interchangeably for ratemaking purposes. Goodwill will not be determined until the closing date of the transaction at which time it will be based on the fair value of Questar's identifiable assets and liabilities as determined by a third party valuation. As stated in the Joint Application, Dominion Questar Gas will not seek recovery of any acquisition premium (goodwill) cost or transaction costs associated with the Merger from its customers. Dominion will not record any portion of the cost to acquire or any purchase price allocation adjustments (including goodwill) associated with the Merger on Dominion Questar Gas' books and is planning to make the required accounting entries associated with the Merger on that basis.

Following the transfer of Questar Pipeline Company to Dominion Midstream, which is subject to Dominion Midstream's Board Approval, Dominion Midstream's US GAAP financial statements will be required to reflect goodwill of Questar Pipeline Company at Dominion's basis on the date of the sale as the acquisition will be considered a reorganization of entities under common control. As a result, Dominion Midstream's basis in Questar Pipeline Company will equal Dominion's cost basis in the assets and liabilities of Questar Pipeline Company.

Prepared by: Susan E. Monks, Accounting Specialist, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-9)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.08
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.08 Please provide the Joint Applicants' working definition of fair value as that term is used in the quantification of goodwill and/or acquisition premium and describe the manner in which the fair value will be calculated and recorded for each relevant entity, including the FERC accounts/subaccounts that will be used for this purpose.

Answer: As defined in Accounting Standards Codification Topic 820, *Fair Value Measurement*, fair value is "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." The fair value of Questar's identifiable assets and liabilities will be determined by a third party valuation performed in accordance with the American Institute of Certified Public Accountants Valuation Standards. Please see the response to OCS 2.06.

Prepared by: Susan E. Monks, Accounting Specialist, Dominion Resource Services, Inc.

EXHIBIT ____ (LK-10)

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.23
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.23 Referencing CIR 1.24, please provide in detail any changes to Questar's ADIT that will result from the Merger that may have an effect on the ADIT balance.

Answer: Detailed changes to Questar Gas Company's ADIT balance as a result of the Merger are not yet available; however, the following discussion identifies where changes in the ADIT balances may be required as a result of the Merger.

Dominion intends to acquire the stock of Questar Corporation. In a stock acquisition, the historical tax bases of the acquired assets and assumed liabilities of Questar Corporation, including its subsidiary Questar Gas Company, generally carry over to Dominion. As a stock transaction Dominion does not anticipate any effect on the existing ADIT balances at Questar Gas Company as a result of the Merger. Questar Gas Company may have net operating losses (NOLs), credit carryforwards, or other relevant tax attributes which will also carry over to Dominion as part of the acquisition, although the ability to utilize the acquired tax attributes may be limited post-acquisition.

Dominion will be required to obtain a valuation performed under Accounting Standards Codification 805, *Business Combinations*, to reflect the fair value of Questar Corporation's assets and liabilities; however, Dominion is not required to push down the fair value to Questar Corporation's subsidiaries, including Questar Gas Company. Conversely, Dominion may be required to adjust the financial accounting basis of acquired assets and liabilities to conform Questar Gas Company's accounting policies to those of Dominion. To the extent that the financial accounting basis of an asset or liability, for which a future taxable or deductible temporary difference exists, is adjusted, deferred tax liabilities or deferred tax assets will be adjusted to account for an increase or decrease in the temporary difference associated with the financial statement account.

Prepared by: Jonathan Bass, Senior Tax Consultant, Dominion Resources Services

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.03.3
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.03.3 Please explain the potential impact, advantages and disadvantages to Dominion Questar Gas customers of selling the Questar Pipeline Company to the Dominion Midstream Limited Partnership rather than retaining Questar Pipeline Company under Dominion Questar Corporation.

Answer: Dominion does not expect there to be any disadvantages to Dominion Questar Gas customers as a result of the contribution of Questar Pipeline Company to DM. The operations and services provided by Questar Pipeline Company are not expected to change as a result of the transaction. While not quantifiable at this time, Dominion expects that Dominion Questar Gas customers could stand to benefit over time from having a large, well capitalized parent company which maintains diverse and attractive capital markets access in the bond, equity, and MLP equity markets (the latter access being supported by the contribution of the Questar Pipeline Company business).

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-11)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.10
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.10 Please provide the Joint Applicants' working definition of transaction costs and list each such cost that falls within this definition (the response to DPU 3.07 only provides examples and does not provide a comprehensive list). In addition, describe the manner in which transaction costs will be incurred and recorded by each relevant entity, including charges to and from other affiliates. Provide and describe the FERC accounts/subaccounts that will be used for these purposes and the costs that will be recorded in each such account/subaccount.

Answer: The costs listed in DPU 3.01 and OCS 2.24 are an all-inclusive list of what Questar Corporation has currently identified as transaction costs. These costs will be incurred by Questar Corporation in account 9302 (non-allocated G&A). These costs will not be charged to any subsidiaries and as a result all of these costs will be borne by shareholders and not customers.

In addition to the estimated transaction costs listed in DPU 3.01, the following estimated transaction costs have been identified by Dominion. These costs will not be passed down to any Questar affiliate.

Legal expenses –estimated	$ 1.5*
Merger –related Financing Costs	70.0- 90.0*
	$71.5- 91.5

Note: All dollar amounts listed are in millions.

*These costs are estimated based on information currently available and are subject to change.

Prepared by: Kelly Mendenhall, General Manager, Regulatory Affairs, Questar Gas Company and Sharon L. Burr, Deputy General Counsel, Dominion Resources

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.24
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Costs, Integration Activities, and Savings

OCS 2.24 Refer to the response to DPU 3.01. Please provide a more detailed analysis of these estimated transaction costs. In your response, please indicate whether the "legal" costs include the costs of the regulatory proceedings in Utah, Wyoming, Idaho, among others.

Answer: Financial advisory services are the costs paid for investment banking fees to broker the Merger. Legal expenses are the costs paid for third party law firms to broker the merger and costs associated with the shareholder lawsuits. These expenses do not include third party legal costs for regulatory proceedings in Utah, Wyoming and Idaho. Acceleration of financing costs include the costs of a Questar Corporation debt financing that was cancelled due to the Merger. Miscellaneous costs include the costs to prepare the proxy filing and shareholder vote. These could include printing costs, third party consultant costs, etc.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.01
Requested by Division of Public Utilities
Date of QGC Response April 15, 2016

DPU 3.01 Page 15 of the Questar 10-K report indicates that the Company expects to incur significant cost associated with the merger for financial advisory services, legal services, revaluation of share-based compensation and acceleration of executive compensation. Please provide an estimate of the total cost to be incurred due to the proposed merger.

Answer: The following estimated costs will be paid by Questar Corporation and will not be passed down to Questar affiliates.

Financial advisory services	$ 21.5
Legal expenses – estimated up to	5.0*
Acceleration of financing costs	2.2
Miscellaneous (proxy filing, shareholder vote, etc.)	2.0
Total	$30.7

Note: All amounts listed as in millions.

* The legal costs are estimated based upon the information currently available but could be higher depending on shareholder lawsuits.

Potential acceleration of executive compensation costs cannot be estimated at this time due to uncertainty of variables and assumptions required to reasonably calculate any such potential costs.

Prepared by: Dave Curtis, Vice President and Controller, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.07
Requested by Division of Public Utilities
Date of QGC Response April 15, 2016

DPU 3.07 The application indicates that the Dominion Questar will not seek to recover "transaction" costs associated with the merger. Please clarify and list the specific costs that would be considered transaction costs.

Answer: Transaction costs include costs incurred to complete the acquisition of the equity interests, including the costs of bringing the merging entities into agreement and obtaining approvals for the Merger, such as legal, regulatory and investment banking fees. For example, the following transaction costs are identified in the response to DPU 3.01: financial advisory services, legal expenses and miscellaneous expenses (proxy filing, shareholder vote, etc.).

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

EXHIBIT ____ (LK-12)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.11
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.11 Please confirm that transaction costs will not be recorded on the accounting books of Questar Gas, or, if they are, they will be charged to and reimbursed either by Questar Corporation or Dominion Resources, Inc.

Answer: Please see the response to OCS 2.10. No transactions costs will be recorded on the accounting books of Questar Gas.

Prepared by: Dave Curtis, Vice President and Controller, Questar Corporation

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.05
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.05 In the event Dominion and Questar complete the Merger, how will the transaction costs be allocated between Dominion and Questar (including any adverse rulings for shareholder lawsuits)? Conversely, if Dominion and Questar are unable to complete the Merger, how will the transaction costs be allocated between Dominion and the new Dominion Questar?

Answer: Any transaction costs related to the Merger will be incurred and expensed at the respective Questar Corporation and Dominion corporate level and will not be passed down to Questar affiliates. In the event that the Merger is terminated, the costs will be borne by the acquirer or acquiree as specified in Section 7.3 of the Agreement and Plan of Merger between Dominion and Questar. To the extent Questar Corporation pays a termination fee, these costs will be kept at the parent level and not passed down to the subsidiaries.

Prepared by: Dave Curtis, Vice President and Corporate Controller, Questar Corporation, and Steven D. Ridge, Director - Financial Analysis, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-13)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.12
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.12 Please provide the Joint Applicants' working definition of transition costs and list each such cost that falls within this definition (the response to DPU 3.08 only provides examples and does not provide a comprehensive list). Explain why the Applicants believe each such cost should be considered a transition cost and not a transaction cost. In addition, describe the manner in which transition costs will be incurred and recorded by each relevant entity, including charges to and from other affiliates. Provide and describe the FERC accounts/subaccounts that will be used for these purposes and the costs that will be recorded in each such account/subaccount.

Answer: Dominion and Questar are currently in the transition process, in which the kinds of details of transition costs requested above are being developed. At this time, it is not possible to identify with specificity all transition costs beyond the examples that were provided in response to DPU 3.08. It is Dominion's and Questar's expectation that as we move through the transition process, the details of costs, how the costs fall into the "transition cost" category, accounting details (FERC account and sub accounts to which they may be charged) will be developed as part of the transition process.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.08
Requested by Division of Public Utilities
Date of QGC Response April 15, 2016

DPU 3.08 The application indicates that the Dominion Questar may defer "transition" costs associated with the merger and may seek to recover these costs in the future. Please clarify and list the specific costs that would be considered transition costs.

Answer: Transition costs are generally expenditures resulting from the preparation and implementation of activities necessary to integrate the purchased entity into the acquiring entity. Examples of transition costs include but are not limited to the integration of financial, IT, human resource, billing, accounting, and telecommunications systems. Other costs could include severance payments to employees, changes to signage, and changes to employee benefit plans, costs to terminate any duplicative leases, contracts and operations, etc. The Company has asked the Commission for approval to create a deferred asset account to track transition costs.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.13
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.13 Refer to page 2 of the Application wherein it states, "Questar Gas requests the Commission to issue an accounting order authorizing it to defer transition costs incurred in connection with the merger, if it chooses to do so, for later recovery if deemed appropriate by the Commission." Refer also to similar language in the direct Testimony of Mr. Wood at page 15, lines 372-374.

a. Provide a detailed description of the Company's proposal to defer and track such costs for purposes of possible later recovery. Address both capital expenditures and expenses.

b. Identify and describe each "transition" cost contemplated for deferral.

c. Please confirm that synergy savings would be deferred as a regulatory liability or otherwise applied to reduce any costs deferred as a regulatory asset.

d. Refer to response to DPU 4.09 wherein the Applicants state that Questar Gas "will only seek recovery of such transition costs to the extent that it can demonstrate that such costs result in a net benefit to customers." Please provide the proposed methodology for the calculation of the "net benefit."

Answer: a. Please refer to response to OCS 2.12. The details around transition cost identification and deferral will be developed as part of the transition process.

b. Please see the responses to DPU 3.08 and OCS 2.12.

c. It is our expectation that any "synergy savings" would be flowed to customers through rates based on lower test year costs in a subsequent rate case. Such lower costs would have the effect of mitigating any transition costs deferred as a regulatory asset and pursuant to the merger commitments, no transition costs will be recoverable unless the company can demonstrate that such costs result in a net benefit to customers.

d. The methodology for calculating the net benefit will be developed as part of the transition process.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-14)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.13
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Accounting

OCS 2.13 Refer to page 2 of the Application wherein it states, "Questar Gas requests the Commission to issue an accounting order authorizing it to defer transition costs incurred in connection with the merger, if it chooses to do so, for later recovery if deemed appropriate by the Commission." Refer also to similar language in the direct Testimony of Mr. Wood at page 15, lines 372-374.

a. Provide a detailed description of the Company's proposal to defer and track such costs for purposes of possible later recovery. Address both capital expenditures and expenses.

b. Identify and describe each "transition" cost contemplated for deferral.

c. Please confirm that synergy savings would be deferred as a regulatory liability or otherwise applied to reduce any costs deferred as a regulatory asset.

d. Refer to response to DPU 4.09 wherein the Applicants state that Questar Gas "will only seek recovery of such transition costs to the extent that it can demonstrate that such costs result in a net benefit to customers." Please provide the proposed methodology for the calculation of the "net benefit."

Answer: a. Please refer to response to OCS 2.12. The details around transition cost identification and deferral will be developed as part of the transition process.

b. Please see the responses to DPU 3.08 and OCS 2.12.

c. It is our expectation that any "synergy savings" would be flowed to customers through rates based on lower test year costs in a subsequent rate case. Such lower costs would have the effect of mitigating any transition costs deferred as a regulatory asset and pursuant to the merger commitments, no transition costs will be recoverable unless the company can demonstrate that such costs result in a net benefit to customers.

d. The methodology for calculating the net benefit will be developed as part of the transition process.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.05
Requested by Office of Consumer Services
Date of QGC Response June 10, 2016

OCS 3.05 Refer to the response to OCS 2.13(c). Please respond to the question that was posed. The question was whether the "synergy savings" would be deferred as a regulatory liability or otherwise applied to reduce any transition costs deferred as a regulatory asset prior to the savings being reflected in a subsequent rate case.

Answer:

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Ocs 3.05

vbadmin
Administrator

Join Date: Oct 2007
Posts: 2248

Ocs 3.05

#1

05-31-2016, 01:49 PM

Refer to the response to OCS 2.13(c). Please respond to the question that was posed. The question was whether the "synergy savings" would be deferred as a regulatory liability or otherwise applied to reduce any transition costs deferred as a regulatory asset prior to the savings being reflected in a subsequent rate case.

Tags: None

Flag

vbadmin
Administrator

Join Date: Oct 2007
Posts: 2248

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Synergy savings will not be deferred as a regulatory liability but would instead be flowed to customers through rates through lower test year costs in a subsequent rate case. As previously stated, the Commission will decide if, when and how any transition costs would be recovered based on evidence provided in a subsequent rate case, including estimated net benefits to customers.

Prepared by: Thomas P. Wohlfarth, Senior Vice President
Regulatory Affairs,
Dominion Resources Services, Inc

Attached Files

OCS 3.05.docx (14.4 KB, 1 view)

Flag

EXHIBIT ____ (LK-15)

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.21
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.21 Please describe any changes in corporate overhead charges and/or cost allocation from Dominion to the Questar regulated entities and Wexpro after the Merger.

Answer: As described in the testimony of Witnesses Farrell and Wood, Questar entities will benefit from efficiencies and economies of scale associated with participating in Dominion's centralized services company model. At this time, Dominion and Questar have not completed the process of identifying the specific corporate functions that would be transferred to a services company to yield such benefits. Presented below are summary descriptions of Questar Corporation's corporate allocation methodology as compared to Dominion's service company model billing method:

Questar corporate cost allocation – A combination of direct charges and allocations

Questar Corporation's costs are directly assigned, when possible, by charging affiliates an hourly rate that includes overheads. Any remaining general and administrative costs that cannot be directly assigned are allocated to subsidiaries using the "Distrigas" formula – a weighted average distribution among the subsidiaries based on their relative share of Gross Plant, Gross Revenues and Gross Payroll.

Dominion services company model – A combination of direct charges and allocations

Under the services company model, the services company's affiliates are billed at cost. Similar to Questar Corporation, when work is performed for an individual affiliate, services company employees charge hours directly to the affiliate at a standardized hourly rate that includes labor, payroll taxes, and benefits, as well as an estimate for overhead costs necessary to support the service being provided (e.g., administrative and general expenses and infrastructure costs). Any remaining services company costs represent work performed for all affiliates, or specific groups of affiliates (e.g., operating segments), and are billed using methods based on relative attributes of the affiliates. Depending upon the nature of the services company department, these attributes include: headcount, square footage, operations and maintenance costs, number of customers, documents processed, network devices, vehicles, etc.

Prepared by: John Ingram, Director-Accounting, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.15
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Costs, Integration Activities, and Savings

OCS 2.15 Please provide a copy of all integration/transition studies, analyses, and reports that address the organization, activities, staffing, costs, and/or savings to integrate Questar Corporation, Questar Pipeline, and Questar Gas into the Dominion organization structure. Please provide updates to your response as the integration/transition process proceeds.

Answer: As stated in the Joint Application, Dominion plans to operate Questar Gas and Questar Pipeline in the same manner they operate today. See the presentation provided at the April 28, 2016 Utah Technical Conference for a description of and status update on the integration process. See also the response to WPSC 2.05 for organizational charts showing the legal entity structure of Questar Corporation and its subsidiaries within Dominion, as well as how Questar is expected to be incorporated into Dominion's operating segment and leadership structures. These organizational charts also reflect the only staffing changes made to date. There are no other formal studies, analysis, or reports on the integration to date. Updates will be provided as the integration process proceeds.

Prepared by: Karla Haislip, Merger & Acquisition Project Director, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.32
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.32 Reference Joint Notice and Application ¶ 59g p. 31.

a. Please explain how Dominion plans to "reduce administrative and operations and maintenance expenses incurred by Dominion Questar Gas" and provide a timeline for the implementation of this plan.

b. Please explain if there has been any analysis or studies completed to quantify the potential costs and benefits to ratepayers due to Dominion's plans reduce administrative and operations and maintenance expenses incurred by Dominion Questar Gas.

c. If so, please provide all relevant documents including how costs and benefits to ratepayers in those areas were quantified.

d. If any costs will be incurred, please explain when these costs would be expected to show up in rates.

Answer: a.-d. See the testimony of Fred G. Wood, III at pages 10-11 in Joint Application Exhibit 6.0 and slide 14 of the Joint Applicants' presentations at the April 28th and 29th technical conferences in Utah and Wyoming respectively. See also the responses to DPU 4.01 and OCS 2.15.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-16)

P.S.C.U. Docket No. 16-057-01
Data Request No. 4.17
Requested by Division of Public Utilities
Date of QGC Response April 27, 2016

DPU 4.17 Please provide both concrete examples of practices or policies which the current Dominion Corporation has in place which would benefit the new Dominion-Questar Gas. Which of these examples could not be adopted by Questar Gas absent the merger?

Answer: Dominion has not compared its practices and policies to those of Questar Gas in sufficient detail to identify those that would benefit the new Dominion-Questar Gas. Below are several examples that the companies plan to explore to determine which ones may be of benefit. It is anticipated that the merger will facilitate more robust and timely collaboration and adoption of such beneficial initiatives by Questar Gas in these and other areas than would otherwise be possible absent the merger.

Line Locating Contractor Partnerships

Dominion has a partnership with its primary line locating contractor to minimize third-party damages via weekly electronic mapping system updates, unconventional locating processes and sharing of lessons learned. The parties are exploring further opportunities to reduce damages via excavation monitoring services and joint root cause investigations.

Diversity Partnerships

Dominion has implemented a Greater Opportunity (GO) Program designed to increase the participation of minority-owned, women-owned and other small disadvantaged businesses in pipeline construction projects. The program involves bid packages sized for smaller capacity contractors and evaluation and mentoring to develop and expand their business.

Service Company Partnerships

Dominion has instituted joint Business Unit/Information Technology (IT) strategy and tactical committees charged with assessing and prioritizing IT system development and ensuring business unit subject matter expert support for the design, development, testing and deployment of such systems.

Process Organization

Dominion's gas distribution operations are organized on a process basis rather than a geographical basis to ensure that processes and procedures are implemented in a consistent manner across the entire service area. Under that structure, Managers are responsible for a specific business process with local Supervisors for field employees engaged in that process.

Outage Response

Dominion utilizes hydraulic modeling to determine the potential impact of an outage and exports the information to an outage management system that dispatches field personnel to safely shut down and restore affected areas. The system also allows the company to make automated outbound calls to customers informing them of the situation and providing updates as needed.

Risk Mitigation

Dominion conducts annual table top exercises that focus on the internal and external communication needed to respond effectively to significant operating events. Similar exercises are performed with outside parties such as first responders and, depending on the scenario, federal, state and local law enforcement and Department of Homeland Security personnel.

Information Technology

Dominion has multiple systems to manage its compliance responsibilities, dispatch employees to field locations, monitor system operating pressures and support effective project management, among other functions, many of which have been recently redesigned and/or implemented to improve operational effectiveness and cost efficiency.

Vacuum Excavation

Dominion has expanded its use of vacuum excavation technology that significantly reduces the job site footprint, improves crew productivity and results in less noticeable restoration. The technology is utilized for compliance-related activities as well as cutting service lines for inactive or abandoned accounts to improve pipeline and public safety.

See also the response to DPU 4.23 describing Dominion's innovative training and development programs.

Prepared by: Jeffrey A. Murphy, Vice President and General Manager – Dominion East Ohio and Dominion Hope

EXHIBIT ____ (LK-17)

P.S.C.U. Docket No. 16-057-01
Data Request No. 4.24
Requested by Division of Public Utilities
Date of QGC Response April 27, 2016

DPU 4.24 Please provide a comparison of the outside training of 811, outside contractors, line locators etc., of each Dominion LDC just prior to Dominion's ownership and five years after.

Answer: Prior to the merger of Consolidated Natural Gas Company ("CNG") with Dominion in 2000, CNG pipeline contractors were being trained and qualified for plastic-joining tasks by CNG's gas LDCs' Training Department. In 1999, PHMSA issued its final Operator Qualification ("OQ") rule, and the LDCs began training and qualifying their pipeline contractors.

Post-merger, around 2004, the LDCs evaluated and selected two third-party providers who were authorized to train and qualify contractors. In 2009, Dominion contracted with a vendor to manage data for contractors performing OQ Covered Task work. The partner vendor's process and model allows for authorization of 2nd and 3rd party evaluators, approved by the signatory Operator companies, to train and qualify contractor employees.

The states of Ohio and West Virginia each have "one call" centers and specific state requirements related to "Call before you dig." While Dominion conducts extensive employee and contractor communications related to the "call before you dig" requirements as well as significant media campaigns targeting the general public, the one-call centers are independent of the Operators and handle their own training.

With regard to Local Emergency Responders (Police/Fire), the Dominion LDCs do the following:

- Both before and after the CNG merger, instructors from the LDCs have visited local fire departments to conduct "Partners in Safety" presentations.
- The LDCs have also hosted large events at our facility where we invite local emergency responders to attend. Topics have included appropriate response to natural gas emergencies, what actions should be taken, what actions should not be taken, what is expected of the fire departments, etc.
- For many years the LDCs have periodically conducted a "Fire School," at which local fire departments are provided training regarding proper natural gas fire-fighting techniques.

- Natural gas safety materials are made available to local emergency responders at the following Web site: https://www.dom.com/residential/dominion-east-ohio/safety/first-responders-and-natural-gas
- The LDCs also have a vendor partner that hosts annual Damage Prevention and Emergency Response meetings targeting excavators and emergency responders in each of the counties where the LDCs have facilities. There is a formal presentation at each of these meetings, followed by a question and answer session. One or more LDC representatives attend each of these meetings to provide Operator-specific information and responses. There are a total of 19 meetings scheduled for 2016.

Prepared by: Scott A. Yant, Mgr. Gas Safety and Training, The East Ohio Gas Company

EXHIBIT ____ (LK-18)

Public Service Commission of Wisconsin
RECEIVED: 08/06/14, 12:26:40 PM

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Energy Corporation for Approval of a Transaction by which Wisconsin Energy Corporation Would Acquire All of the Outstanding Common Stock of Integrys Energy Group, Inc.	)))))	Docket No.:

**DIRECT TESTIMONY OF
JOHN J. REED IN SUPPORT OF APPLICATION
BY WISCONSIN ENERGY CORPORATION**

I. INTRODUCTION AND PURPOSE

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

A. My name is John J. Reed. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric") and CE Capital, Inc. located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Wisconsin Energy Corporation ("WEC").

Q. Please describe your educational background and professional experience in the energy and utility industries.

A. I have more than 35 years of experience in the energy industry, and have worked as an executive in, and consultant and economist to, the energy industry. Over the past 26 years, I have directed the energy consulting services of Concentric, Navigant Consulting, and Reed Consulting Group. I have served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to

Q. How might WEC Energy Group generate savings over time?

A. Merger-related savings typically accrue over time, and after upfront investment, through enhanced purchasing power, economies of scale, joint resource planning over a larger and more diverse system, the documentation, adoption and implementation of best practices, other efficiencies in operations and maintenance and project management, sharing administrative and other services over a larger organization, and the improved use of technology. Some specific areas where merger synergy savings are typically found include: insurance, shareholder services, professional services (*e.g.*, accounting, legal), credit facilities, advertising, and supply chain economies (*e.g.*, procurement, inventory, and contract services).

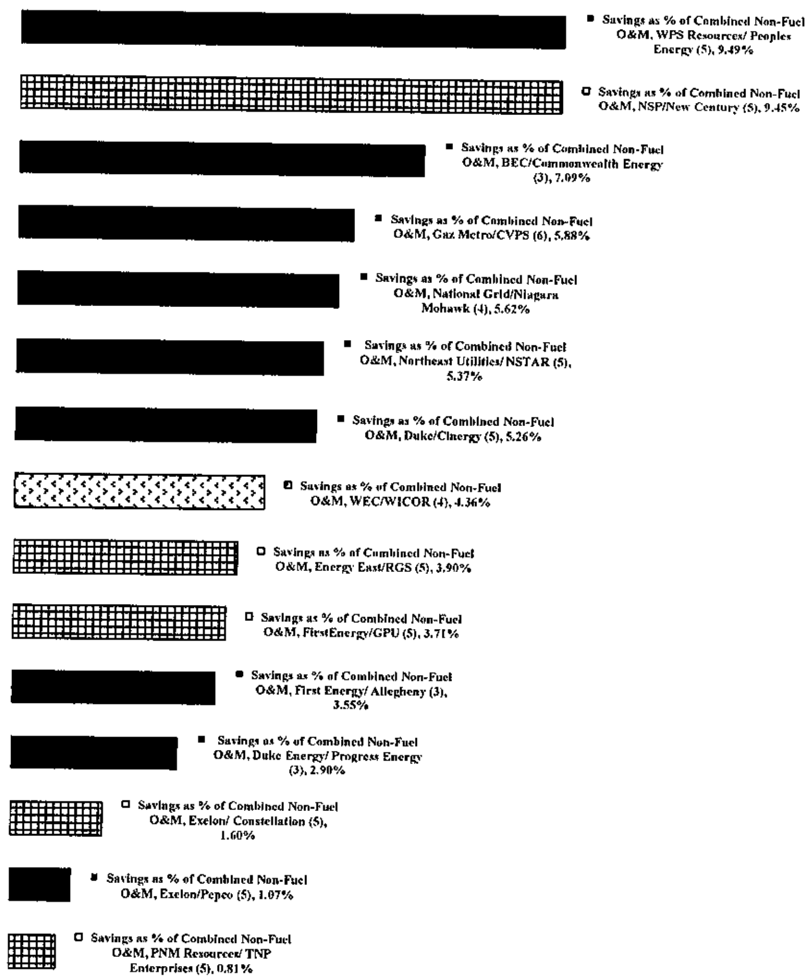
Developing and executing merger integration plans and identifying and realizing synergy savings is a detailed undertaking which takes time to accomplish, particularly in strategic mergers like the Transaction.

Q. What is your view of the merger synergy savings which might be realized from the Transaction?

A. I believe that if it is approved as proposed, the Transaction is likely to generate net savings in the range of three to five percent of non-fuel O&M of the combined company after a five to ten year ramp-up period relative to what non-fuel O&M for the Companies would have been absent the Transaction.

While neither the Companies nor I have conducted a detailed analysis of the potential merger synergy savings specific to the merger of WEC and Integrys, I have examined the synergy savings attributable to many other mergers. My view on the savings which might be realized from the Transaction is based on this examination as well as my knowledge of the Companies, their past merger integration activities, and merger synergy savings generally. Below is a chart showing the non-fuel O&M savings that were, or were expected to be, achieved in other recent mergers. These savings are net of the transition-related costs to achieve them which may include various reorganization and integration costs.

Chart 3: Survey of Historical Synergy Savings



Note: Synergy savings represent steady-state non-fuel O&M savings, net of costs to achieve. Parenthetical after each transaction signifies the assumed number of years necessary to achieve steady-state synergy savings. For mergers represented by checkerboard bars, only cumulative savings data was available and an annual savings value was estimated by taking the average annual savings over the forecast period provided. For the WEC/WICOR merger, synergy savings are actual savings as calculated after the merger was completed, and as filed with the Wisconsin PSC.

As shown in the chart above, expected net savings in non-fuel O&M in recent transactions have a central tendency in the range of 3% to 5% of combined non-fuel O&M. As I noted earlier, savings are realized after upfront investment. The mergers shown in Chart 3 were not expected to typically generate net O&M savings immediately after the merger closed, and those savings were expected to increase to a "steady state" level over a period of years.

In addition to potential non-fuel O&M savings, the Transaction can also be expected to favorably affect capital expenditures and fuel costs over the longer term. Capital expenditure savings can occur through the consolidation or avoidance of spending in areas such as IT systems and call center systems, and fuel savings have been demonstrated through joint procurement and asset management programs, which could occur here in gas pipeline and storage initiatives. On the gas side, the combined company could also be more effective in promoting the development of new pipeline infrastructure into the region and securing more economical negotiated rates for transportation services.

In considering this information, it is important to recognize that each of WEC and Integrys has been involved in other mergers which have already yielded merger savings (in the case of Integrys, recently) and WEC has made post-merger commitments that will slow the rate at which new merger synergies can be achieved.

Q. Why is it reasonable to expect that this level of savings will eventually be achievable for the WEC Energy Group?

A. Both WEC and Integrys have successfully completed integration programs after past mergers. The Transaction also has characteristics that are consistent with other recent mergers that had estimated long-term synergies in this range, including the Northeast Utilities/NSTAR merger. That merger was also not undertaken based on an expectation of large near-term merger synergies and it expected longer-term) savings of approximately 5% of non-fuel O&M costs, based on the existence of two overlapping utility services (gas and electric), adjacent service areas, and supportive regulatory environments. In my opinion, these same characteristics apply to the current Transaction.

Q. If these synergies or savings are achieved, will the benefits be seen by the customers of the operating companies?

A. Yes, they will, as these savings are achieved over the longer term. As I mentioned earlier, there are not immediate rate impacts expected from the merger. However, the shared services model of the WEC Energy Group (as reflected in the proposed affiliated interest agreements) will have the effect of eventually reducing administrative costs across the entire merged company, and each operating company's share of these net savings will be reflected in their cost of service in future rate filings. My experience with other mergers also indicates that these savings can help delay the need for future rate increases. Therefore, each operating company's customers will benefit from the merger, unlocking savings over the longer term.

Q. Has WEC provided any assurances regarding the potential for cross-subsidization within WEC Energy Group?

A. Yes. As I noted earlier in my testimony and as discussed in more detail in Mr. Lauber's testimony, WEC is seeking the Commission's approval of new affiliated interest agreements that reflect the merger and allow WEC and Integrys companies, including WBS, to provide services to one another where it is in customers' best interests to do so. Further, WEC has proposed no changes to the corporate structure of any of the combined company's individual operating utilities as a result of the Transaction. Each of the individual operating utilities will continue to maintain unique capital structures, costs of capital and financing requirements. These proposals will allow the utilities to benefit

EXHIBIT ____ (LK-19)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.12
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.12 Please provide additional information concerning the $692 million distribution in 2015 from Dominion Gas Holdings to Dominion Resources. (Dominion Resources 10-K, page 81)

Answer: Dominion Gas Holdings, LLC ("DGH") is a wholly owned operating subsidiary of Dominion Resources, Inc. ("DRI"). DGH was formed in late 2013 for the purpose of providing a financing vehicle for certain of Dominion's regulated gas infrastructure businesses, notably Dominion Transmission, Inc. ("DTI"), East Ohio Gas ("EOG"), and Dominion Iroquois, Inc. Financing those assets in this manner enables investors (and in particular fixed income investors) to obtain additional information that enables them to differentiate their investments between those gas assets and certain other of Dominion's electric utility businesses which are also debt financed independently.

At the time of the creation and inaugural financing of DGH in late 2013, the intention was to bring the equity ratio of DGH, over time, to the appropriate and prudent level for regulated businesses of this nature. This was achieved through a series of debt financings at DGH, the proceeds of which were largely distributed to DRI through dividends or the repayment of intercompany debt. Between an inaugural debt issue at DGH at the time of its creation in 2013 and subsequent debt financings in 2014 and 2015, this plan has largely been achieved, with the equity ratio of DGH going from effectively 100% equity at the time of its creation to an equity ratio of approximately 50.9% (based on a FERC definition that excludes short-term debt) at year-end 2015.

The $692 million distribution from DGH to DRI in 2015 was the last step in the process outlined above. No distribution is planned from DGH to DRI in 2016, given the target equity capitalization range has been achieved.

There is no intention for Questar Gas Company or its affiliates to be contributed to or otherwise become a subsidiary of DGH, and there is no intention for the financial information or balance sheet of DGH to become directly relevant in future regulatory proceedings involving Questar Gas Company or its affiliates.

Prepared by: Richard M. Davis, Director Finance, Dominion Resources, Services Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.13
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.13 Please provide additional information concerning the amount of the distributions that have been paid by the operating entities within Dominion Gas Holdings.

Answer: The Dominion-operated subsidiaries of Dominion Gas Holdings, LLC ("DGH"), Dominion Transmission, Inc. ("DTI") and East Ohio Gas ("EOG"), obtain all funding, beyond operating cash flows, from DGH either as equity capital contributions or intercompany debt. In turn, cash flows of each operating subsidiary are generally swept to DGH each quarter as dividend payments in amounts that support DGH's quarterly dividend payments to its parent company, Dominion Resources, Inc. Neither DTI nor EOG issue external debt, have public ratings on any of their debt, or have publically available financial statements.

Prepared by: Richard M. Davis, Director Corporate Finance, Dominion Resources Services, Inc.

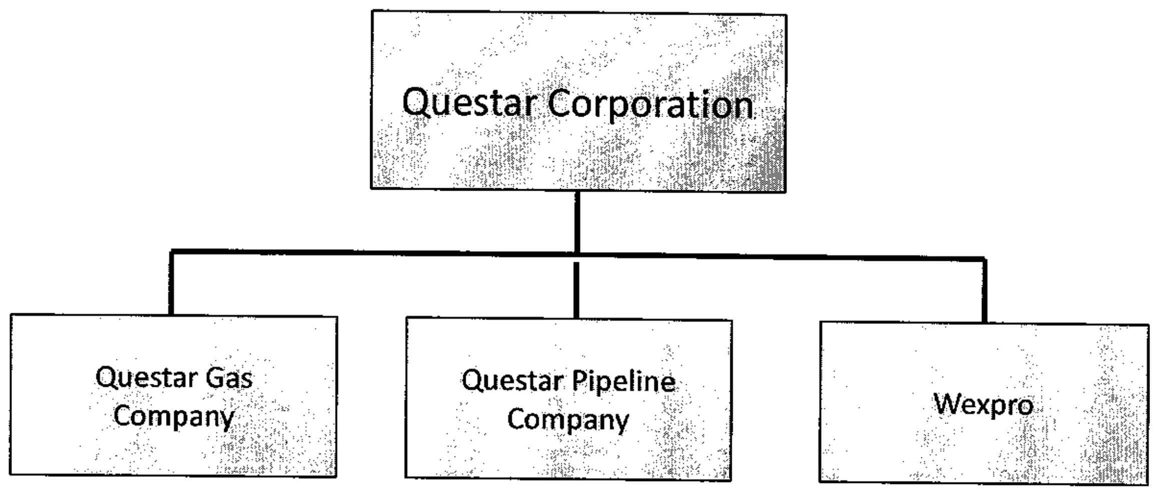
P.S.C.U. Docket No. 16-057-01
Data Request No. 4.14
Requested by Division of Public Utilities
Date of QGC Response April 27, 2016

DPU 4.14 Please provide a pre-merger and post-merger organization chart for Questar Gas and Dominion-Questar Gas from the highest level down to the supervisor level.

Answer: The current organizational chart for Questar Gas is attached as DPU 4.14 Attachment 1. As discussed in the Joint Application (paragraph 33), Dominion has no plan to change the organizational structure of Dominion Questar Gas operations as a result of the Merger.

Prepared by: Jeff Callor, General Manager, Financial Planning and Analysis
Jennifer C. Wiggins, HR Project & Strategic Change Manager, Operations & Delivery, Dominion Resources Services, Inc.

Questar Organization Chart



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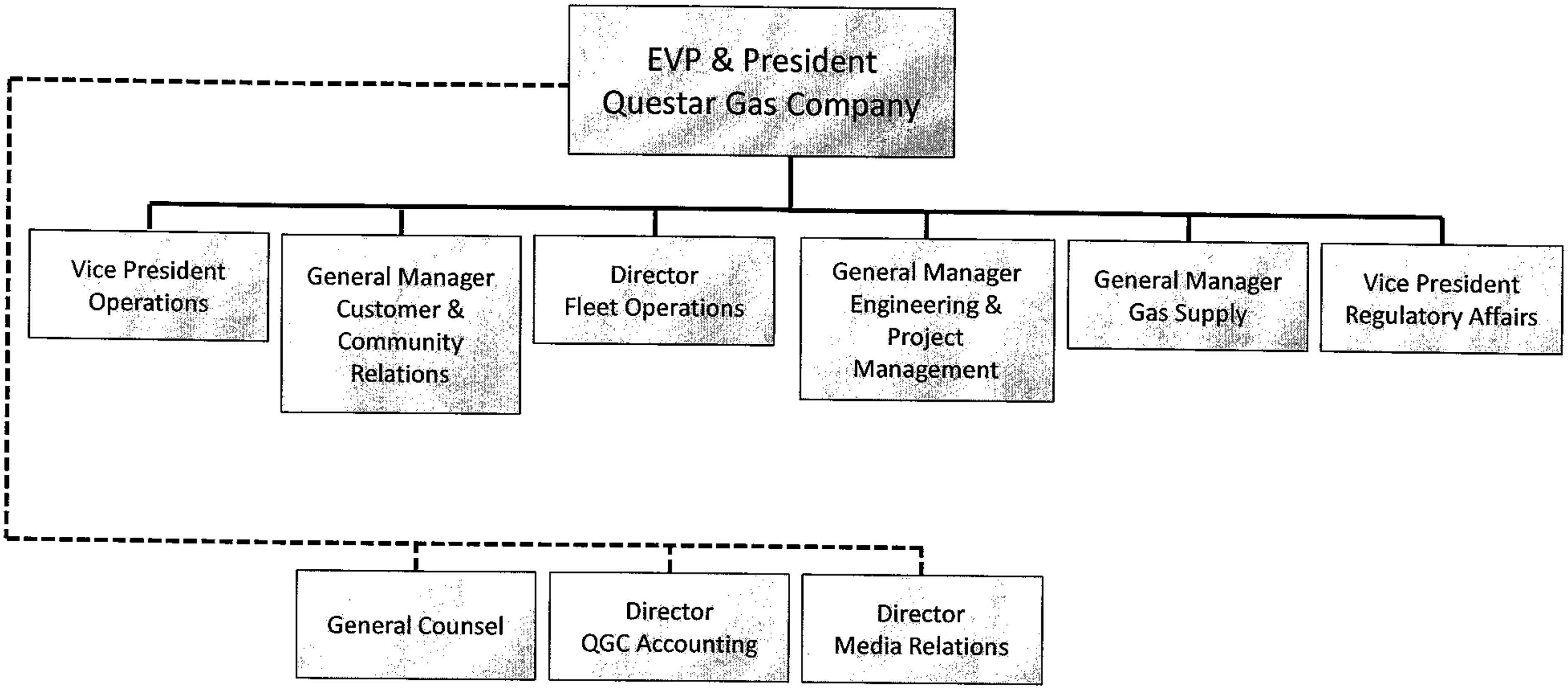
EVP & President - QGC



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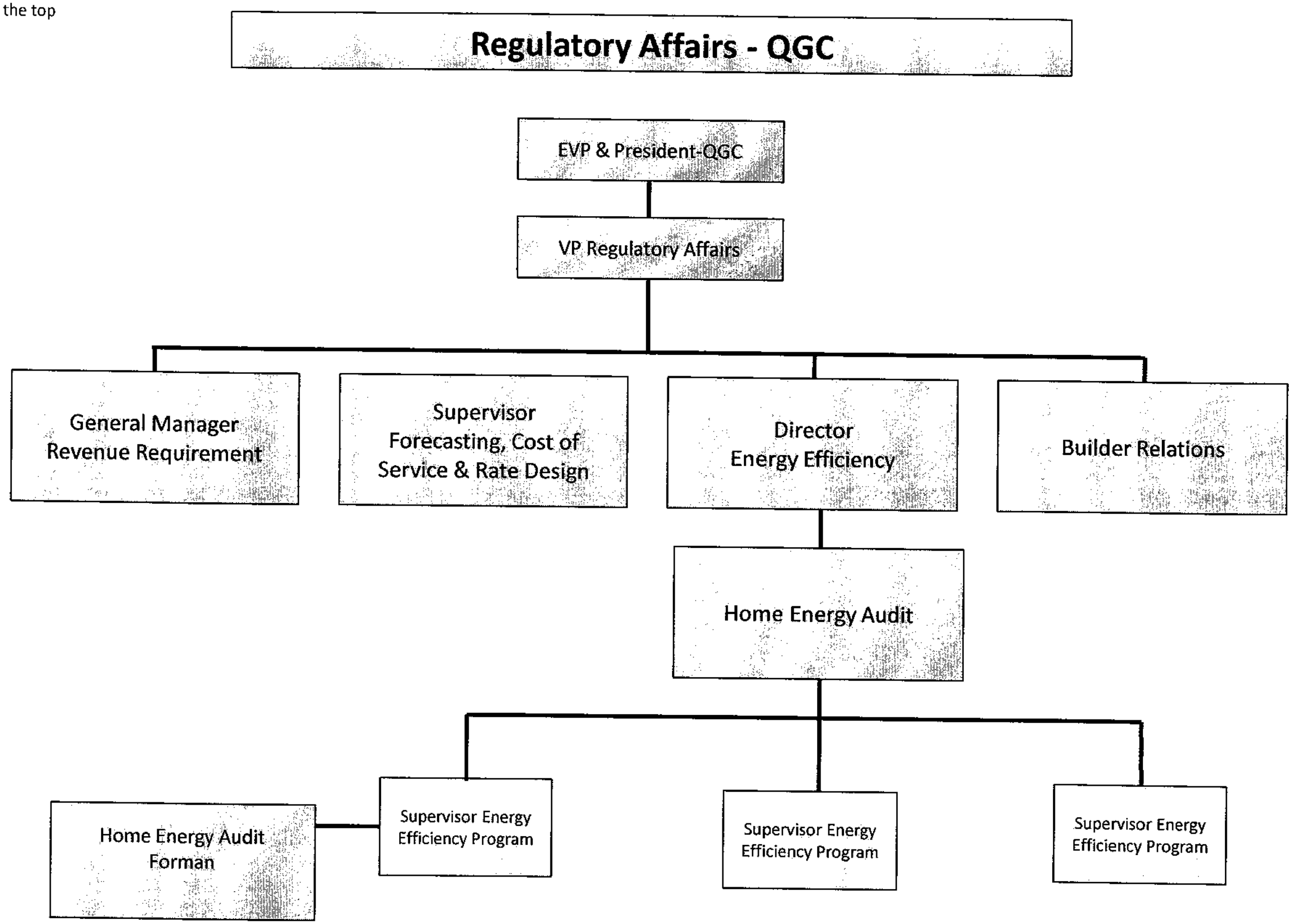

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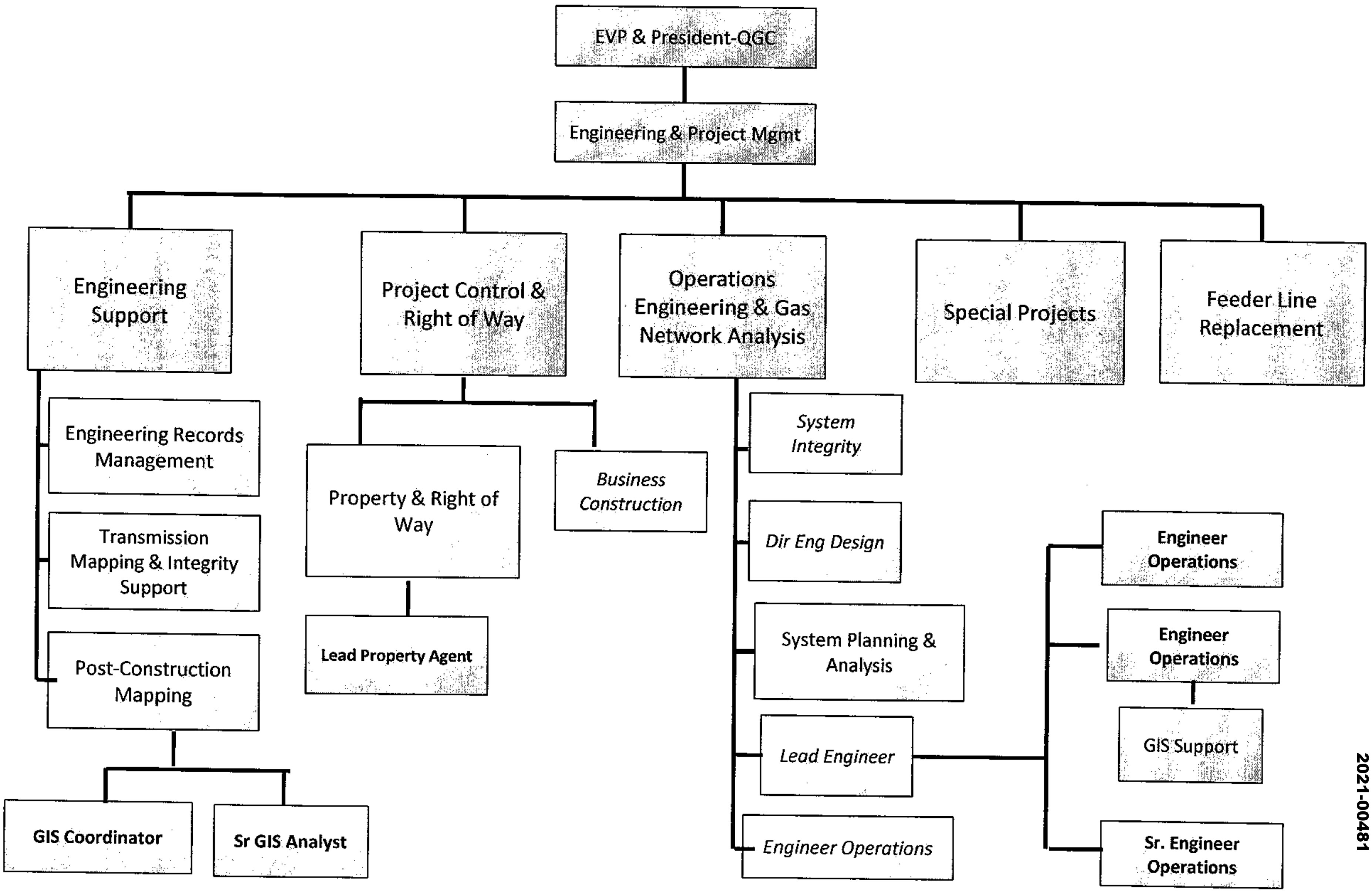
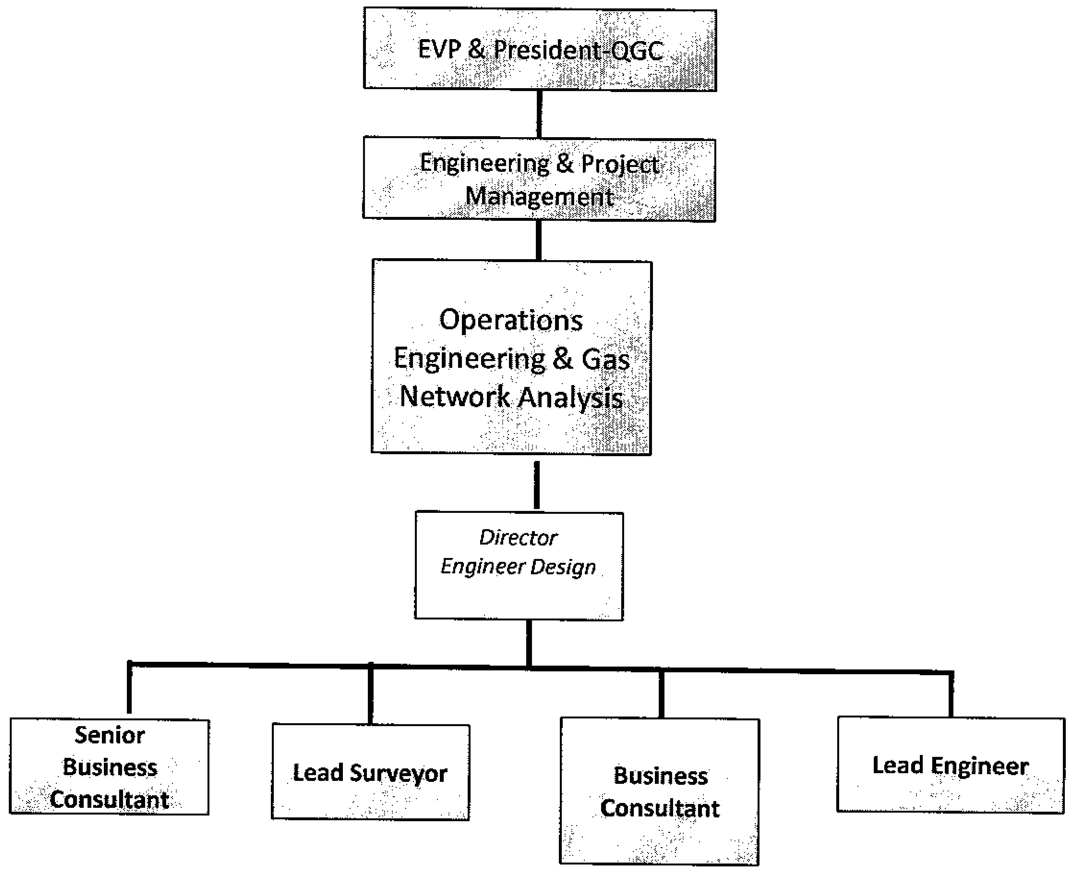


Engineering & Project Management - QGC



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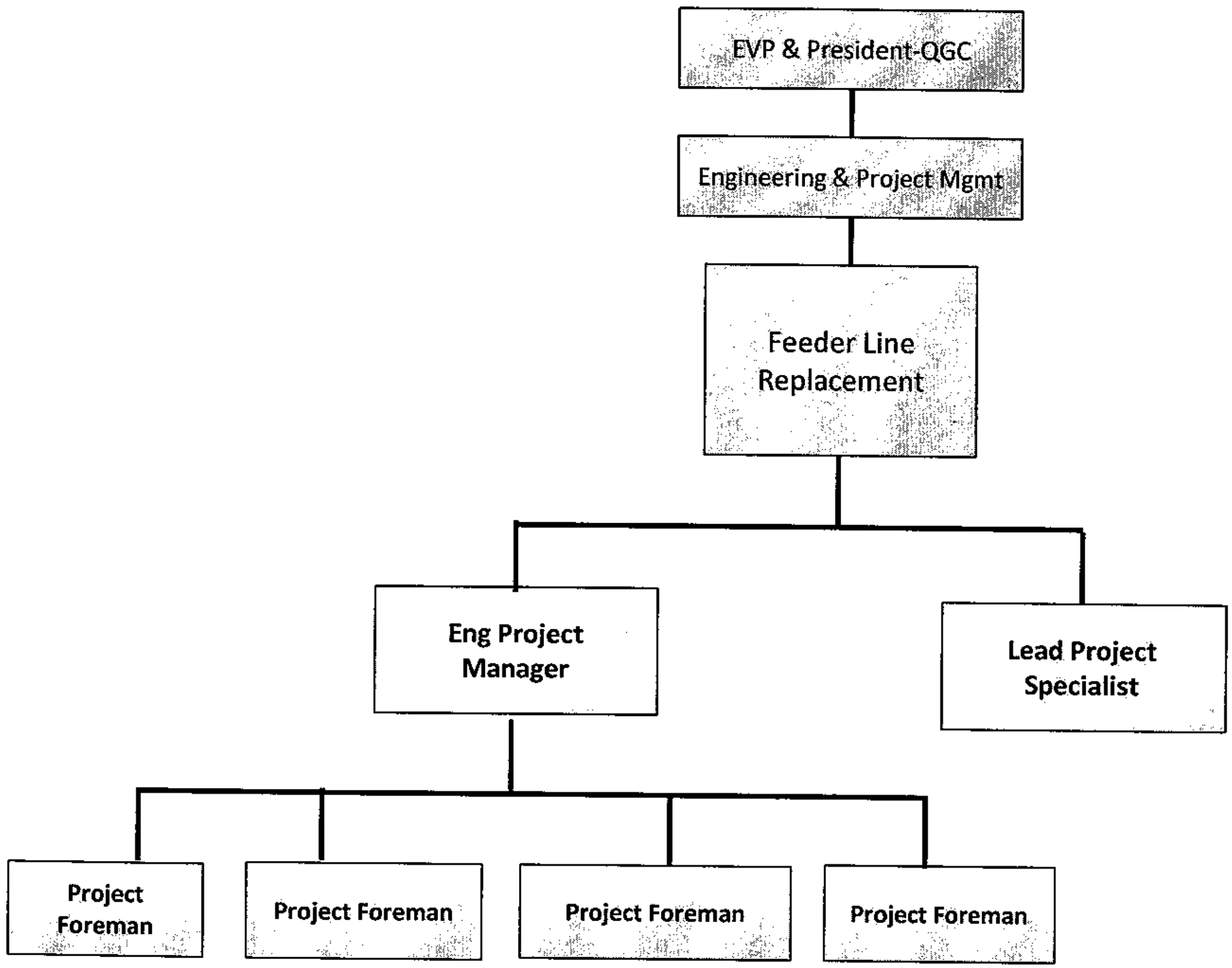
Engineering & Project Management - QGC



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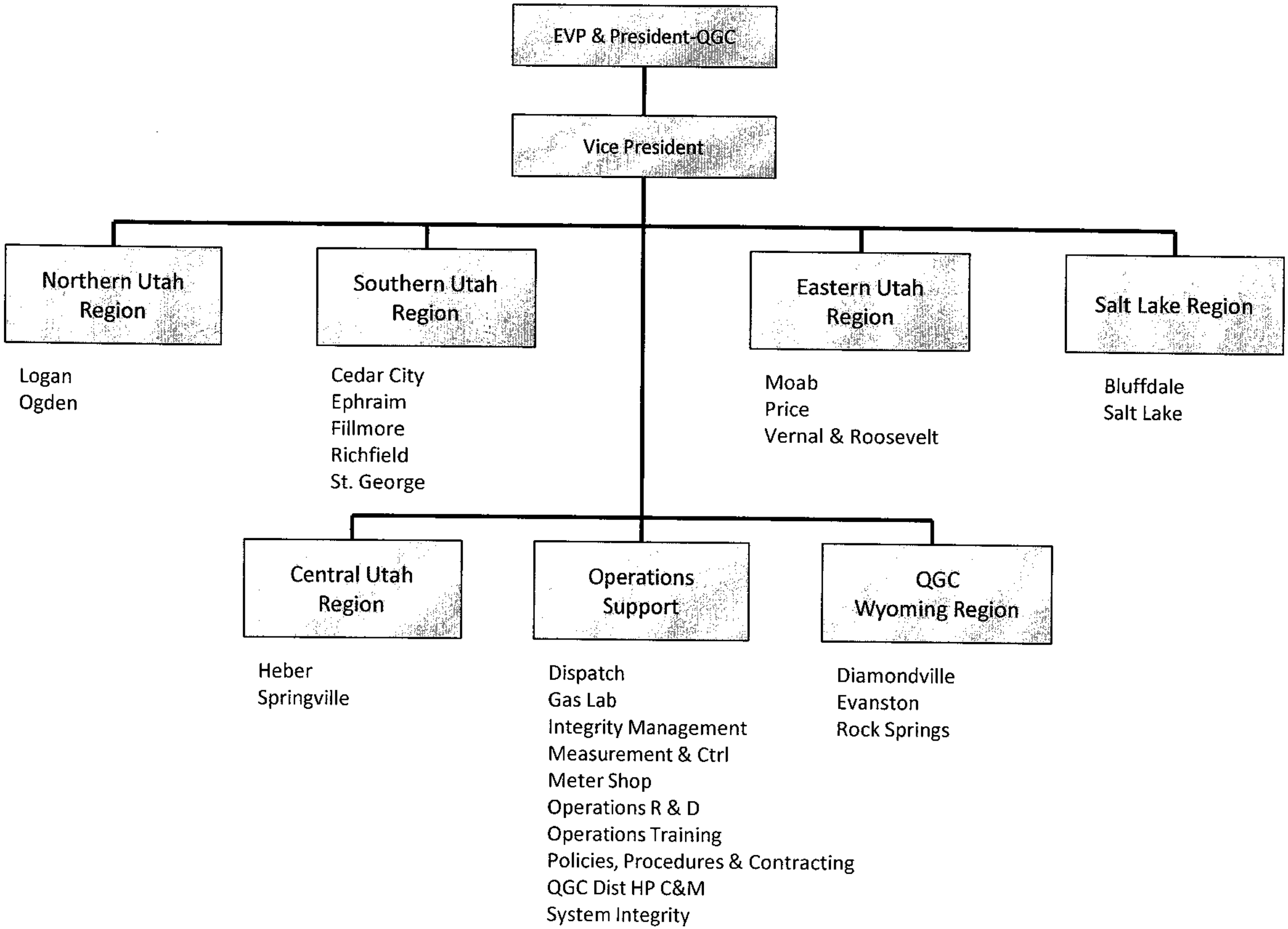
Operations - QGC



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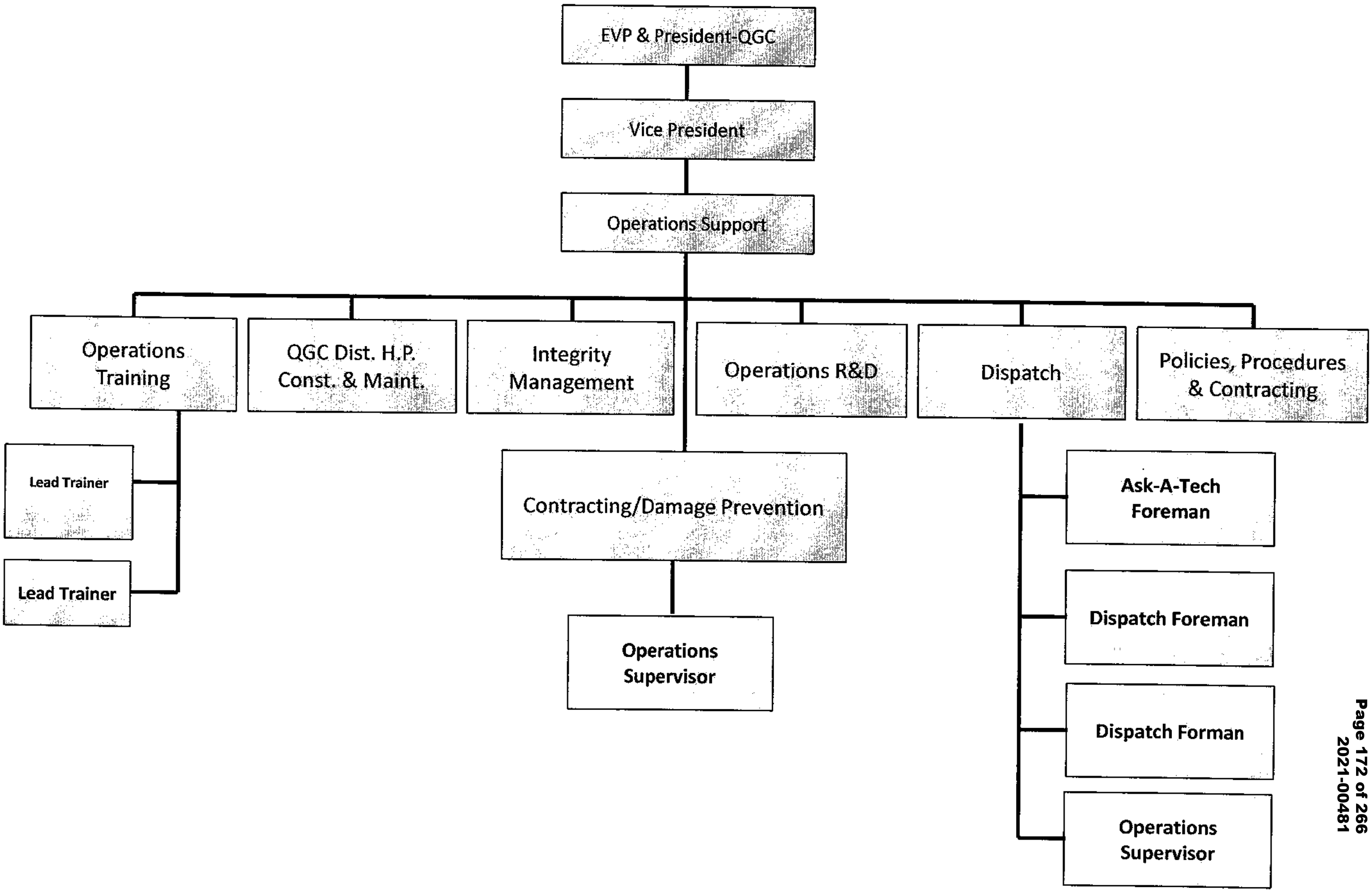
Operations Support - QGC



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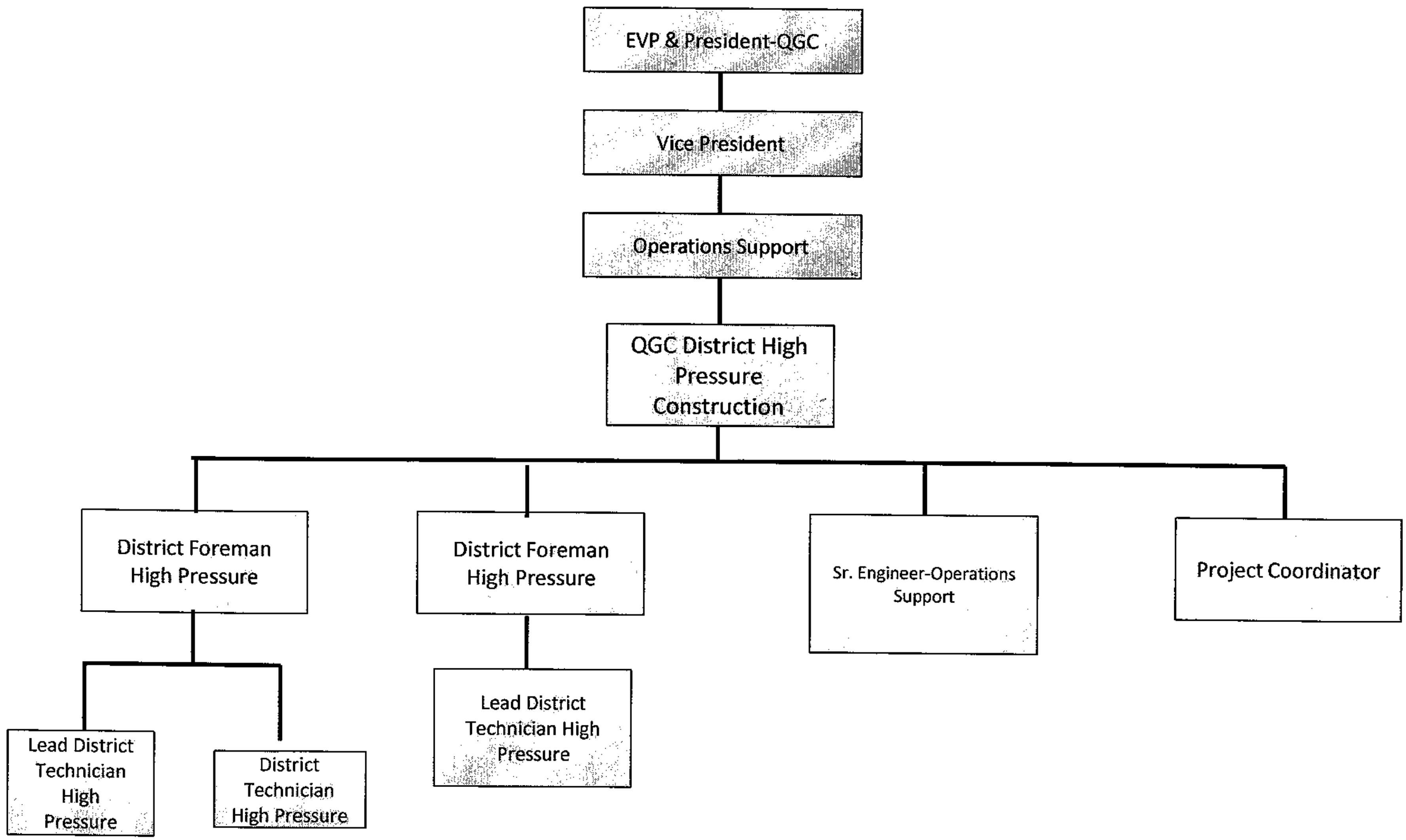
Operations Support - QGC



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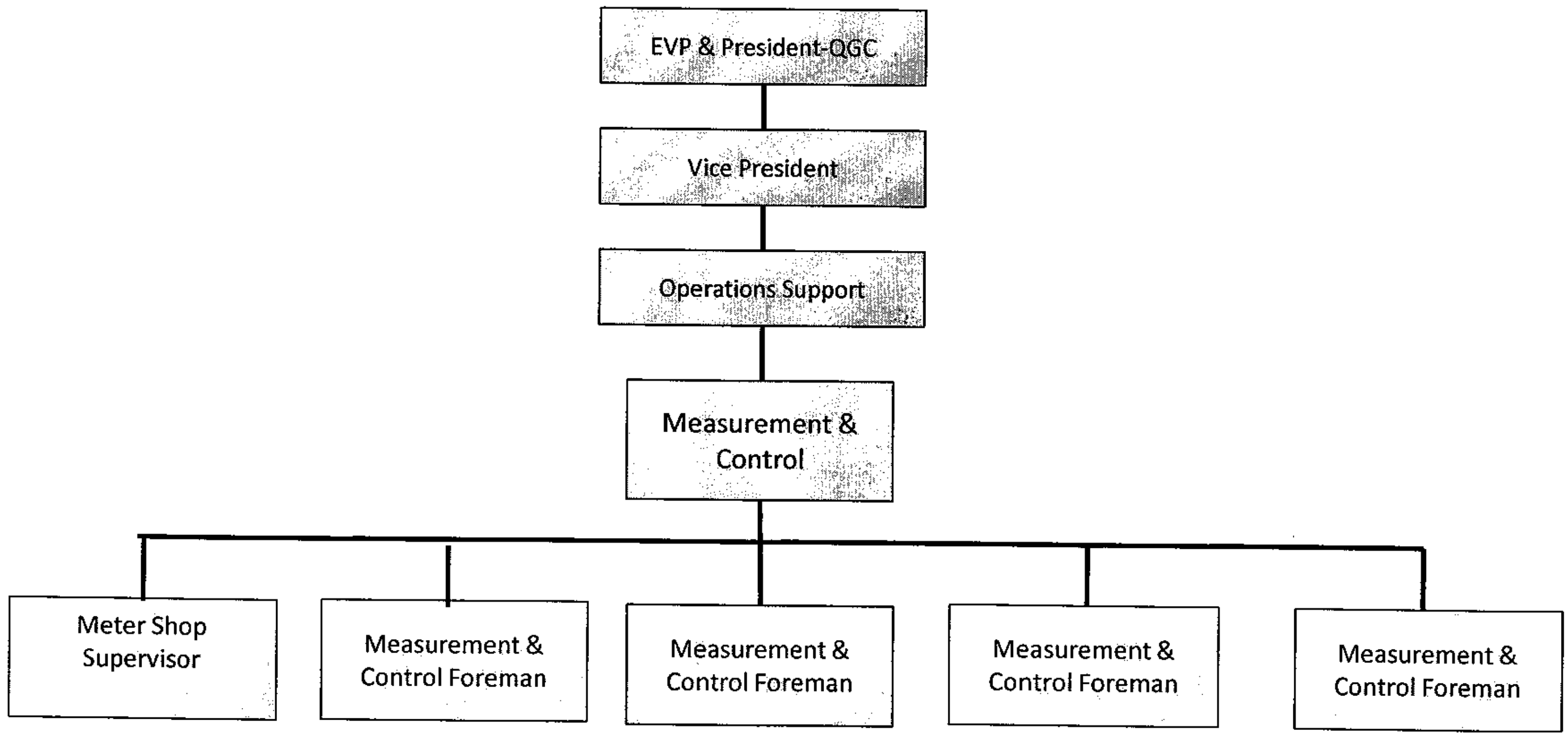
Operations Support - QGC



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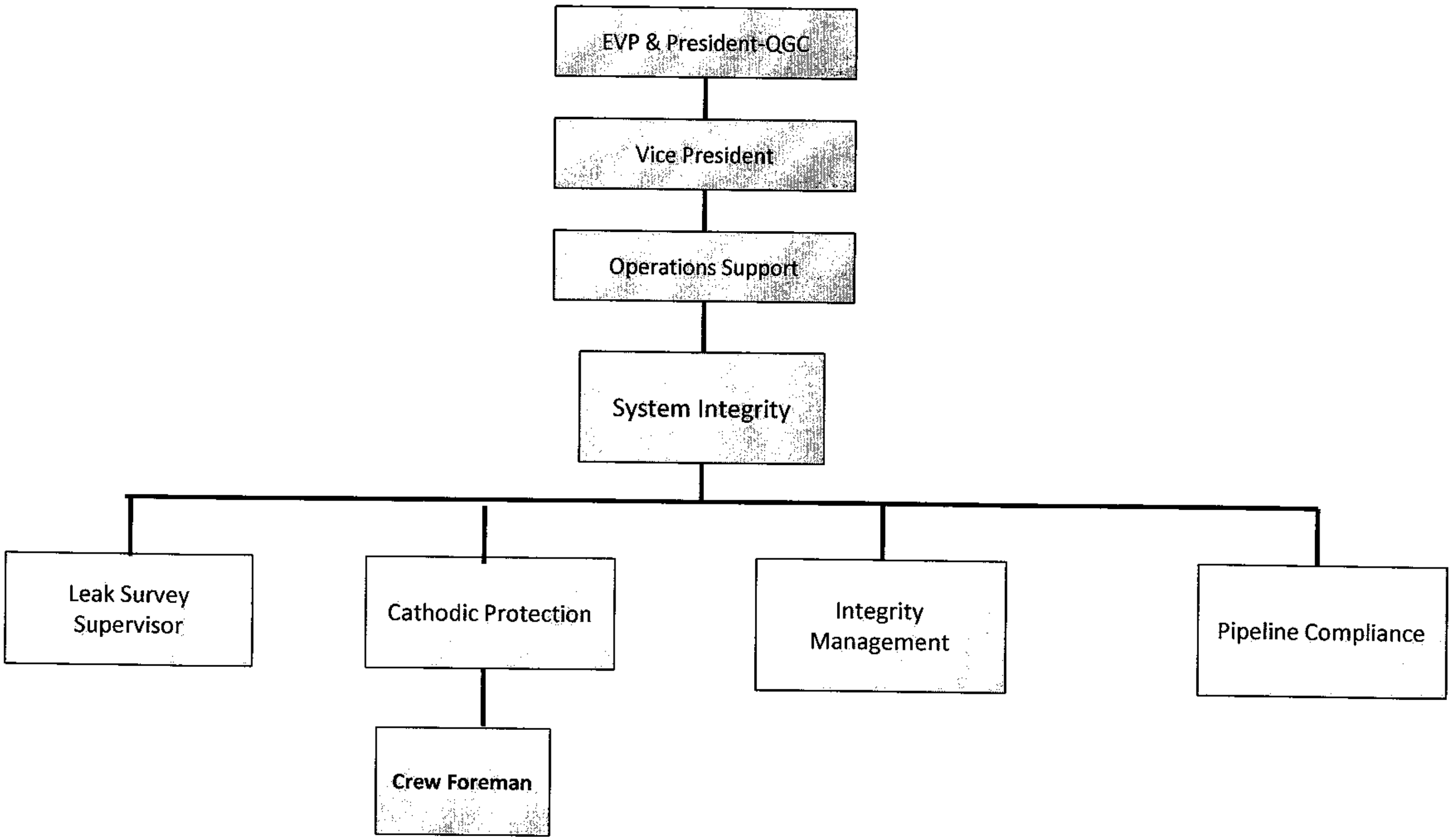
Operations Support - QGC



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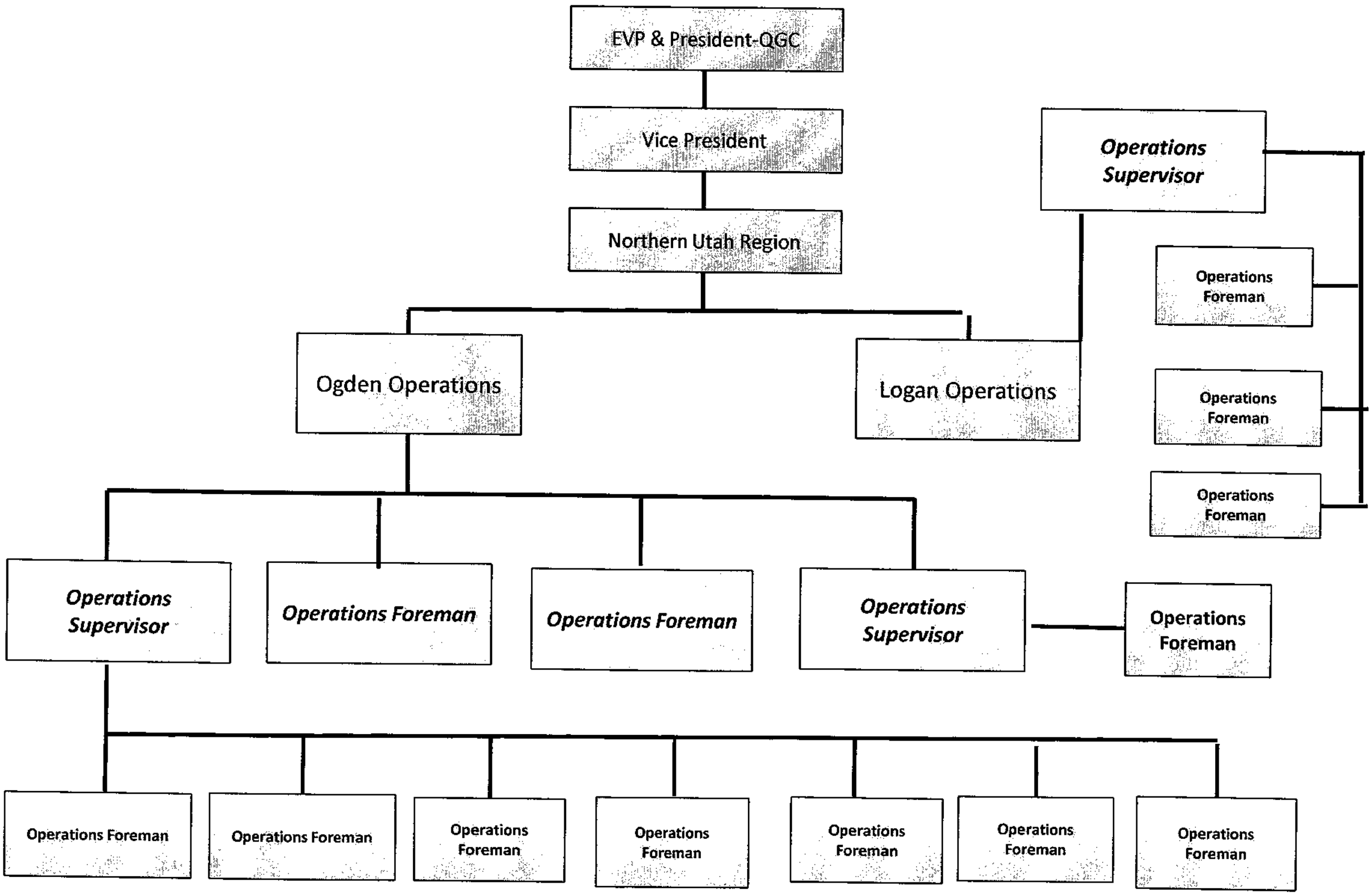
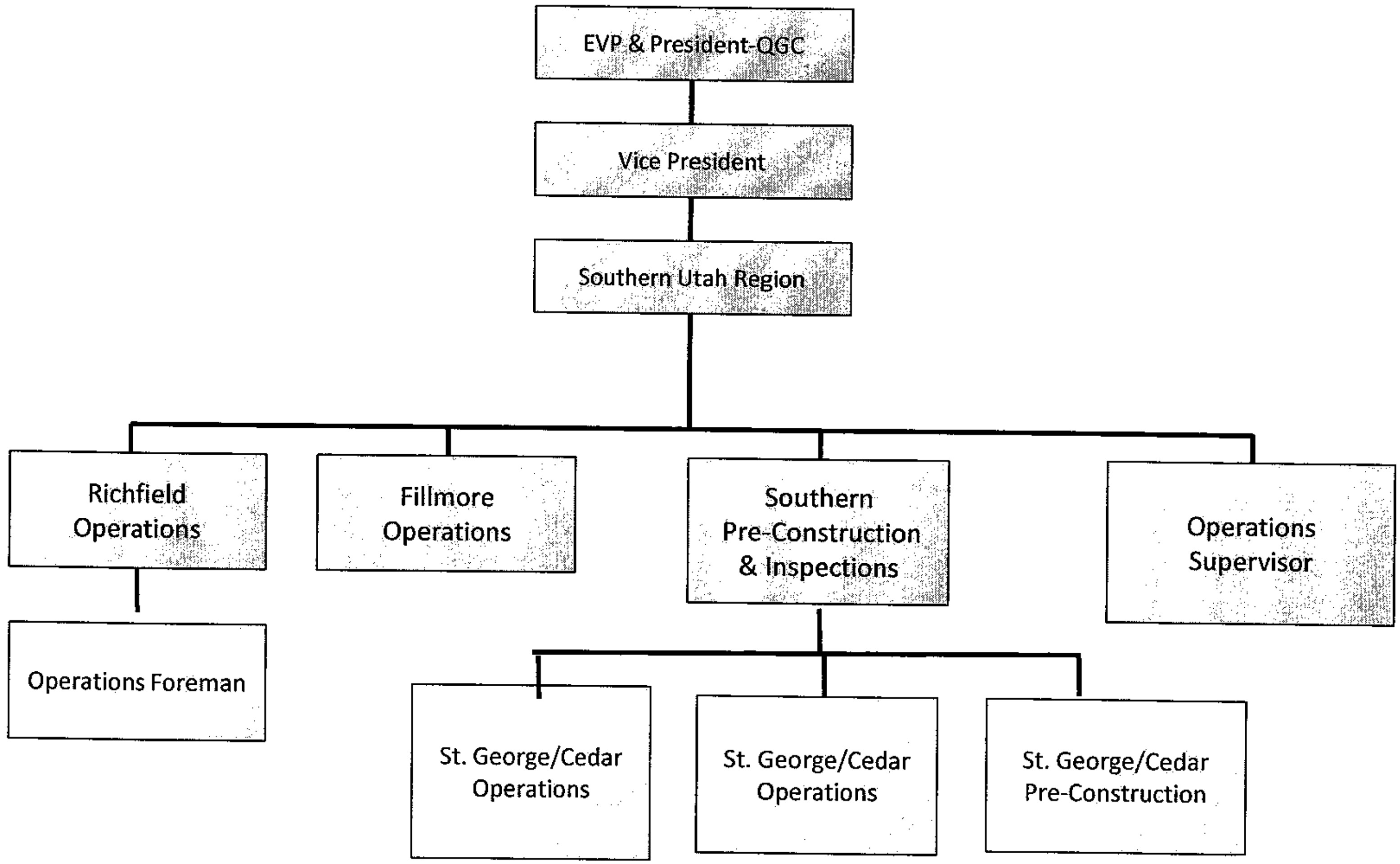
Northern Utah Region - QGC



Southern Utah Region - QGC



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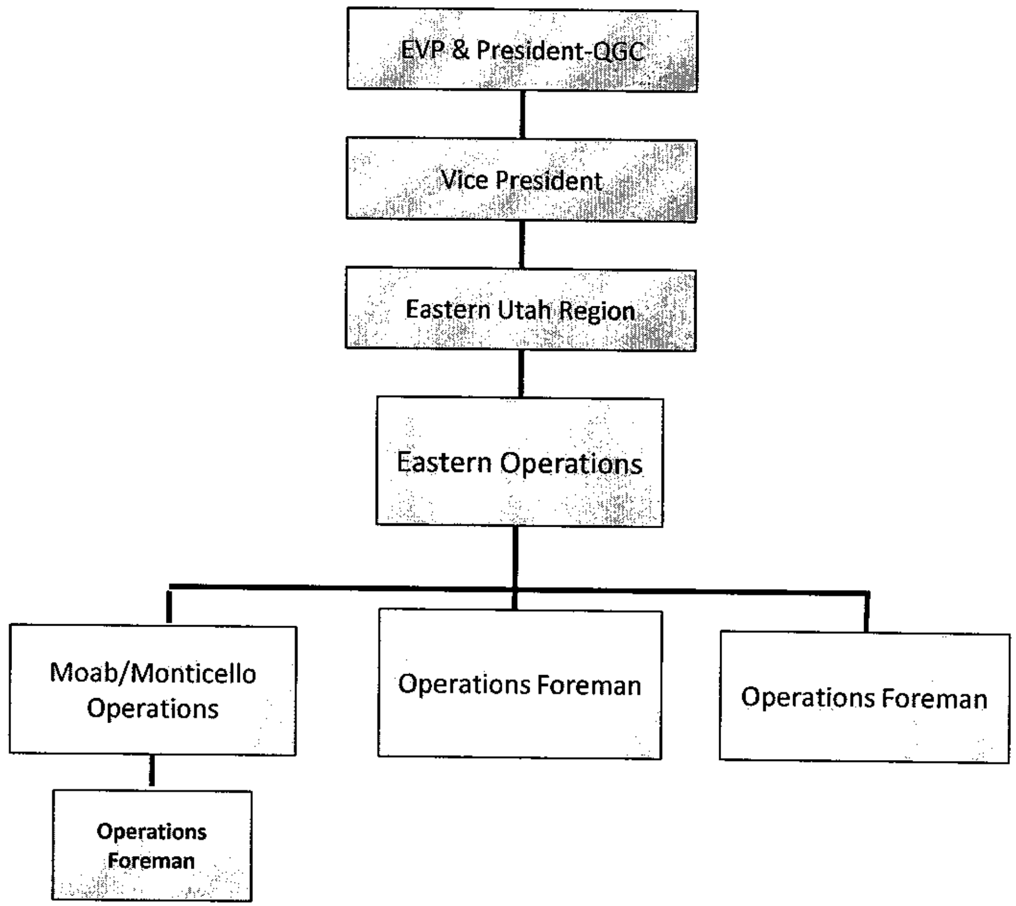
Eastern Utah Region - QGC



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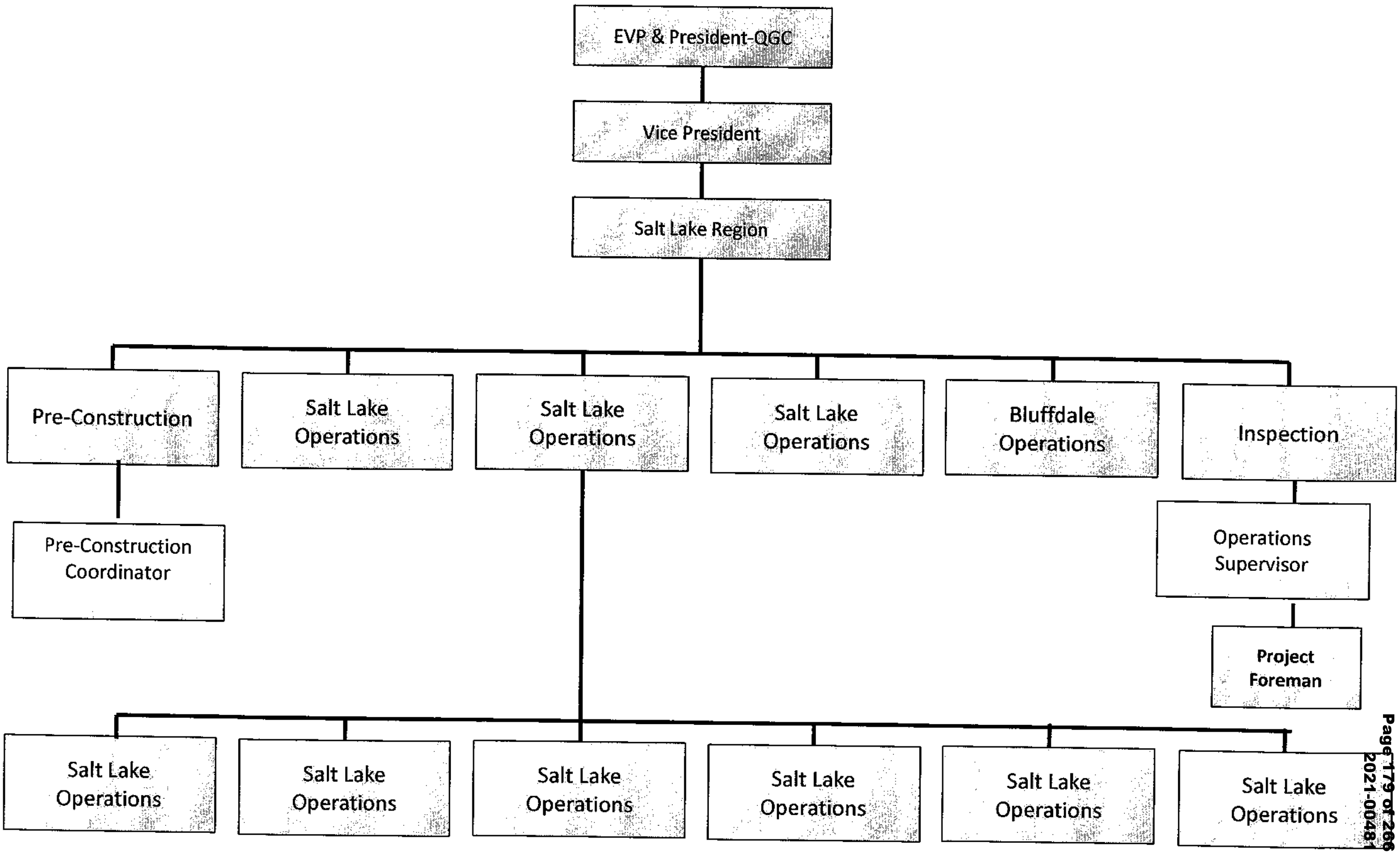
Salt Lake Region - QGC



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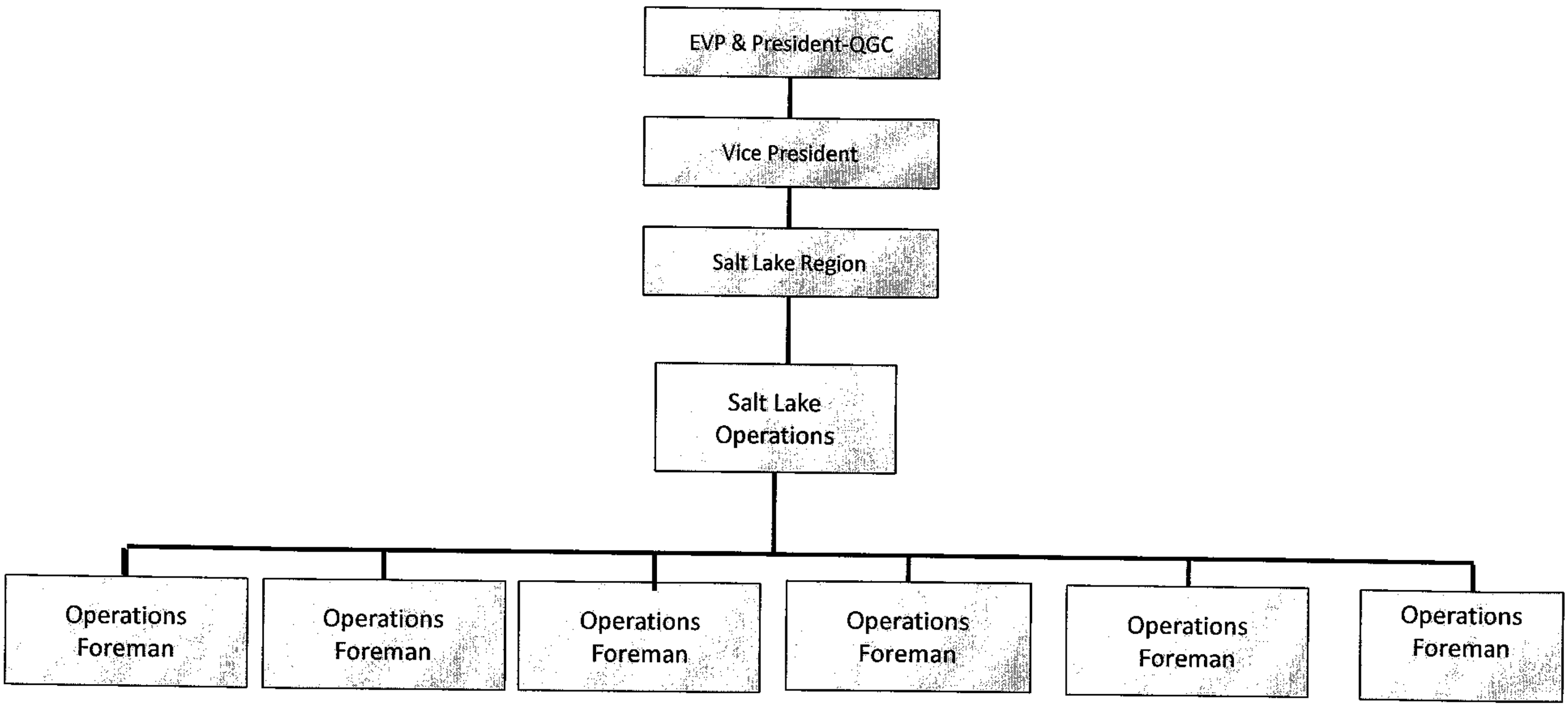
Salt Lake Region - QGC



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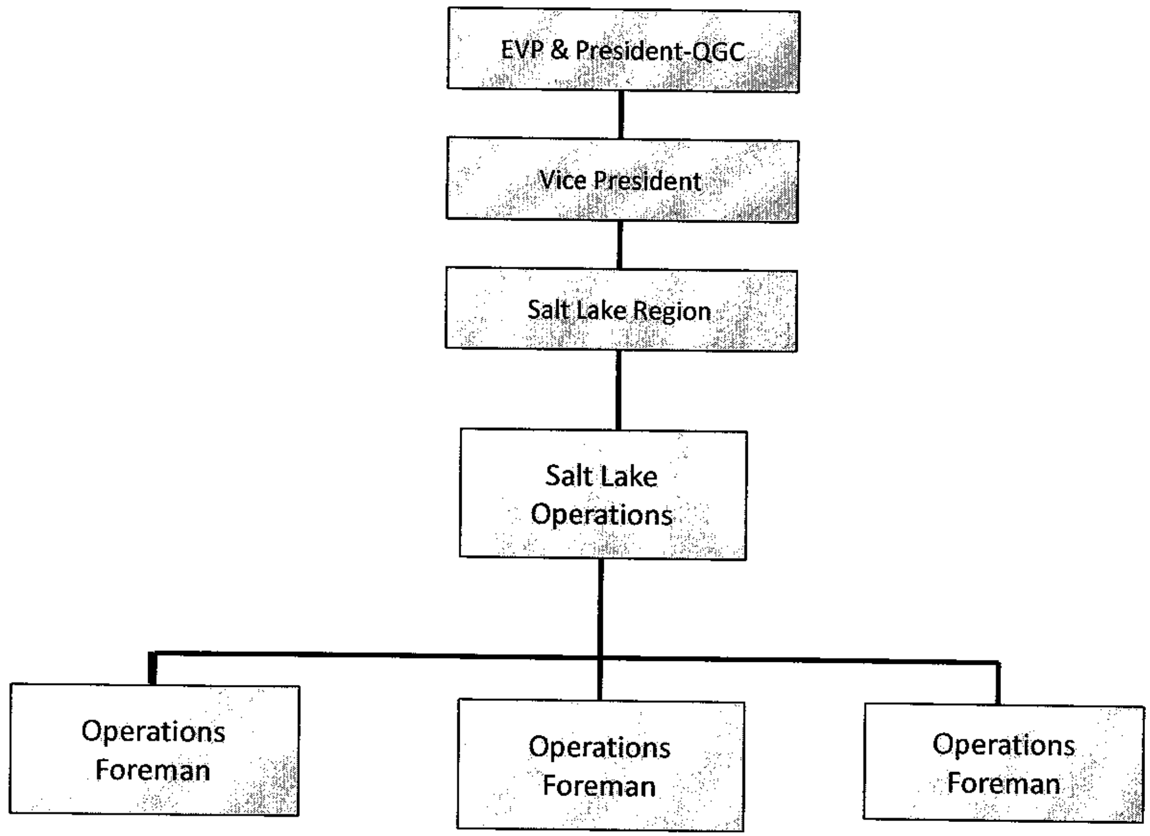
Salt Lake Region - QGC



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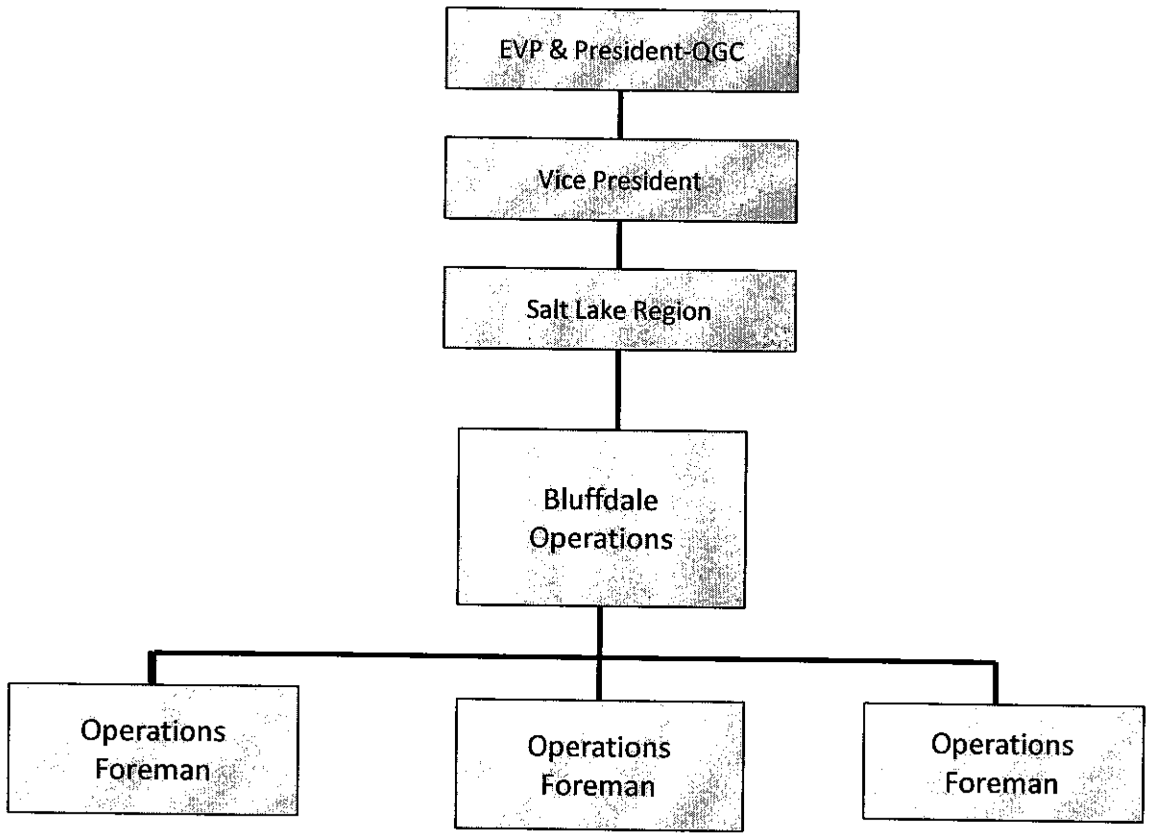
Salt Lake Region - QGC



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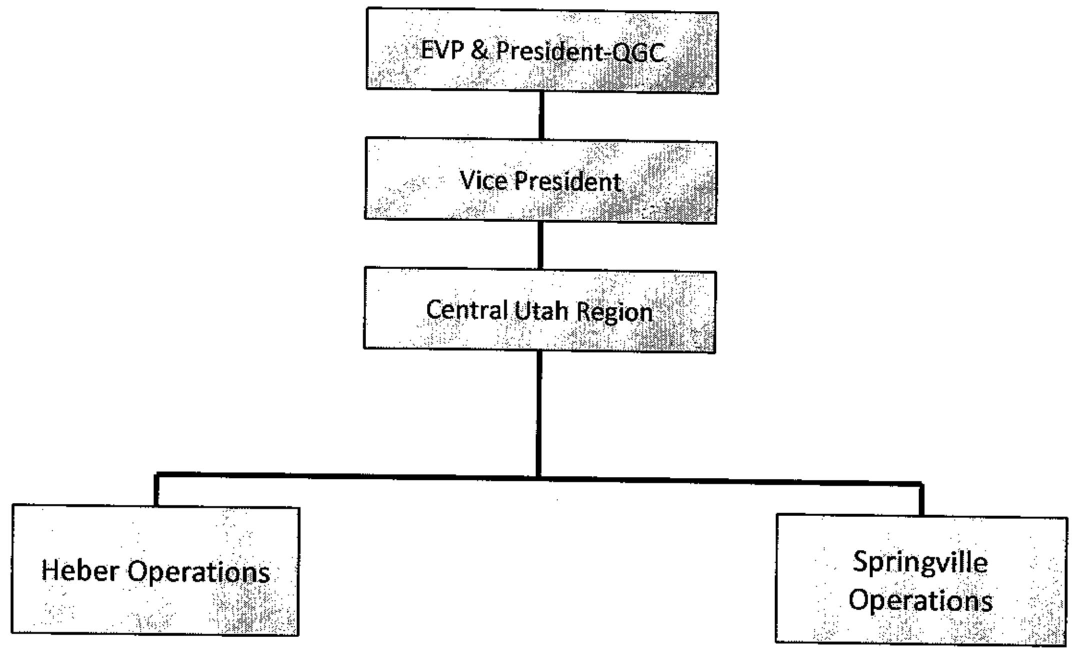
Central Utah Region - QGC



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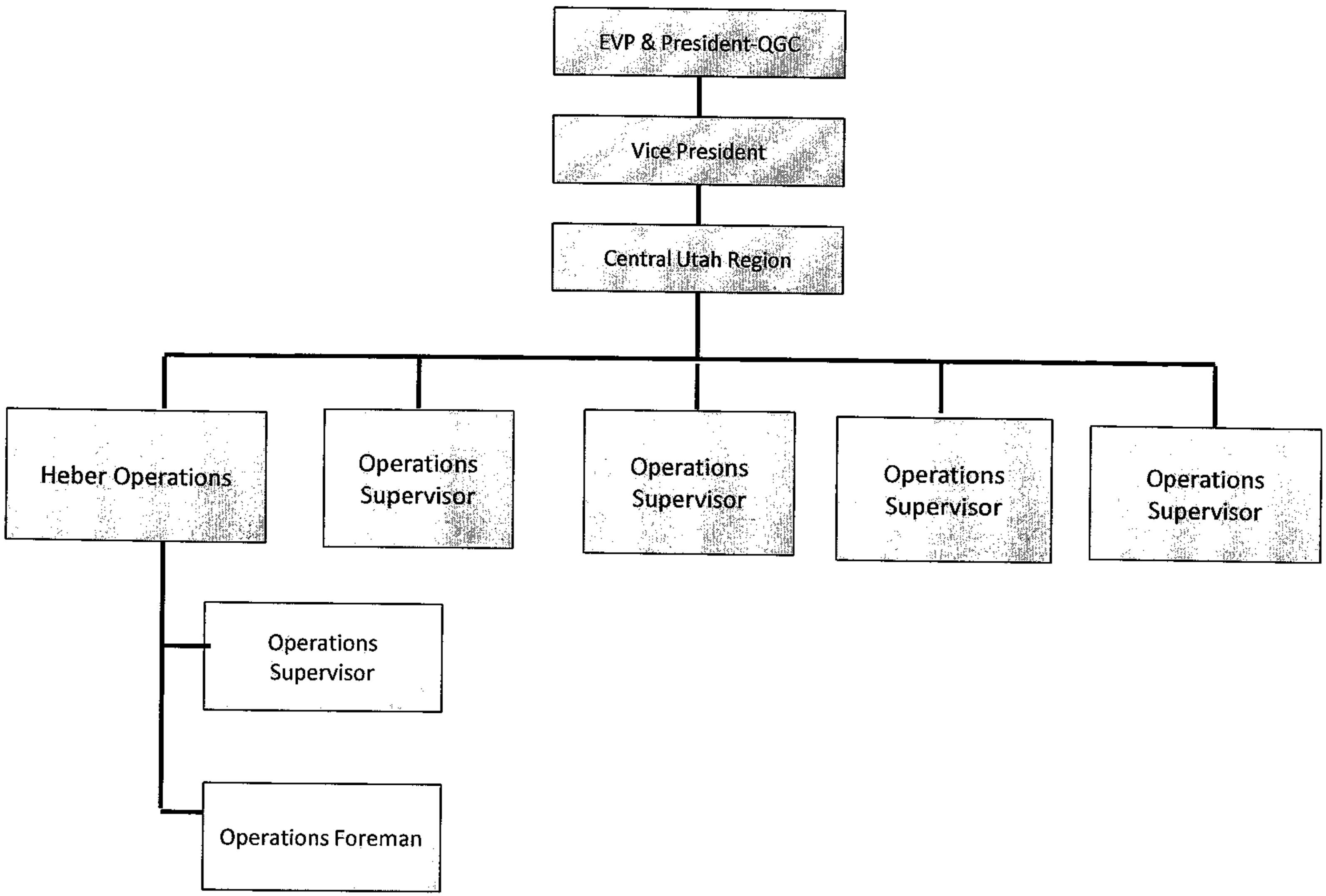
Central Utah Region - QGC



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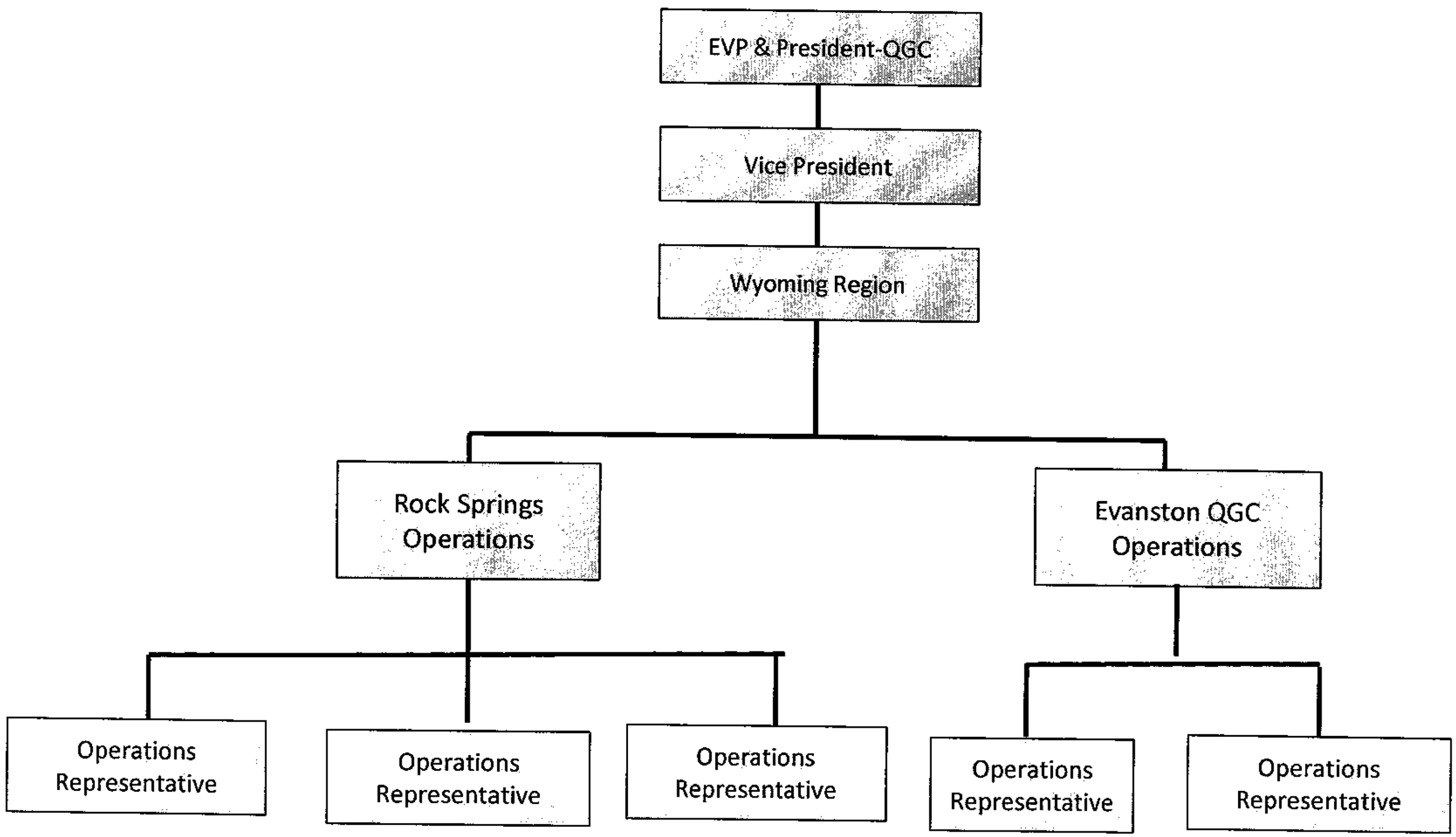
Wyoming Region - QGC



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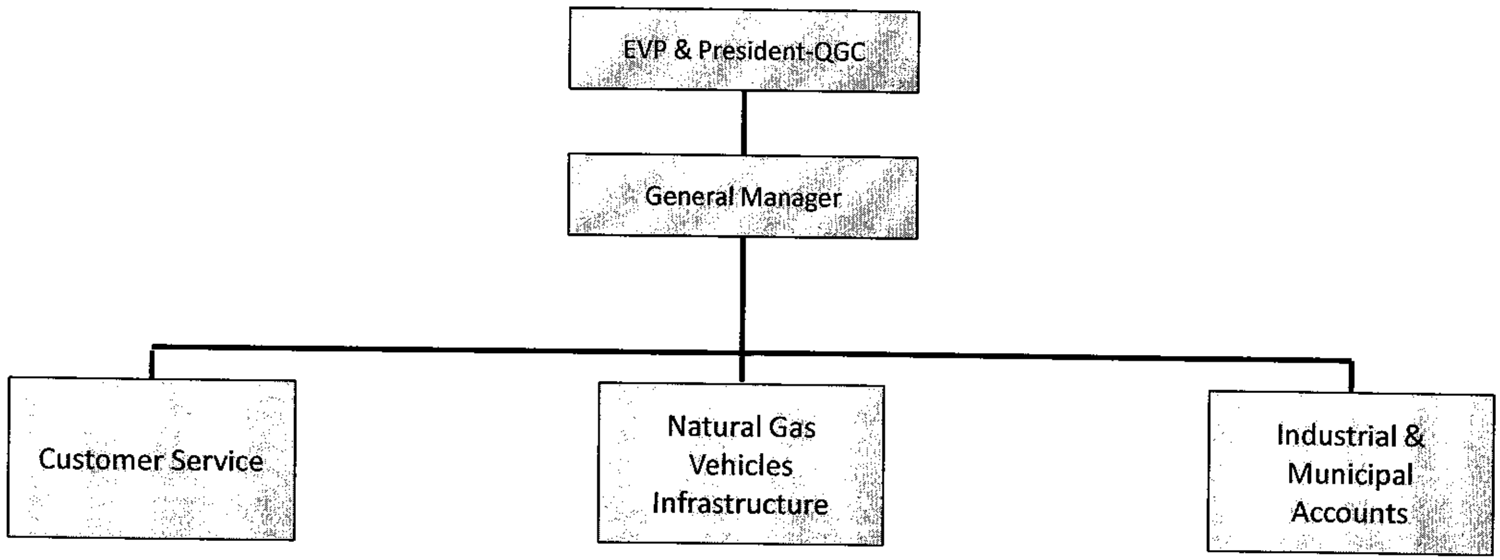
Customer & Community Relations - QGC



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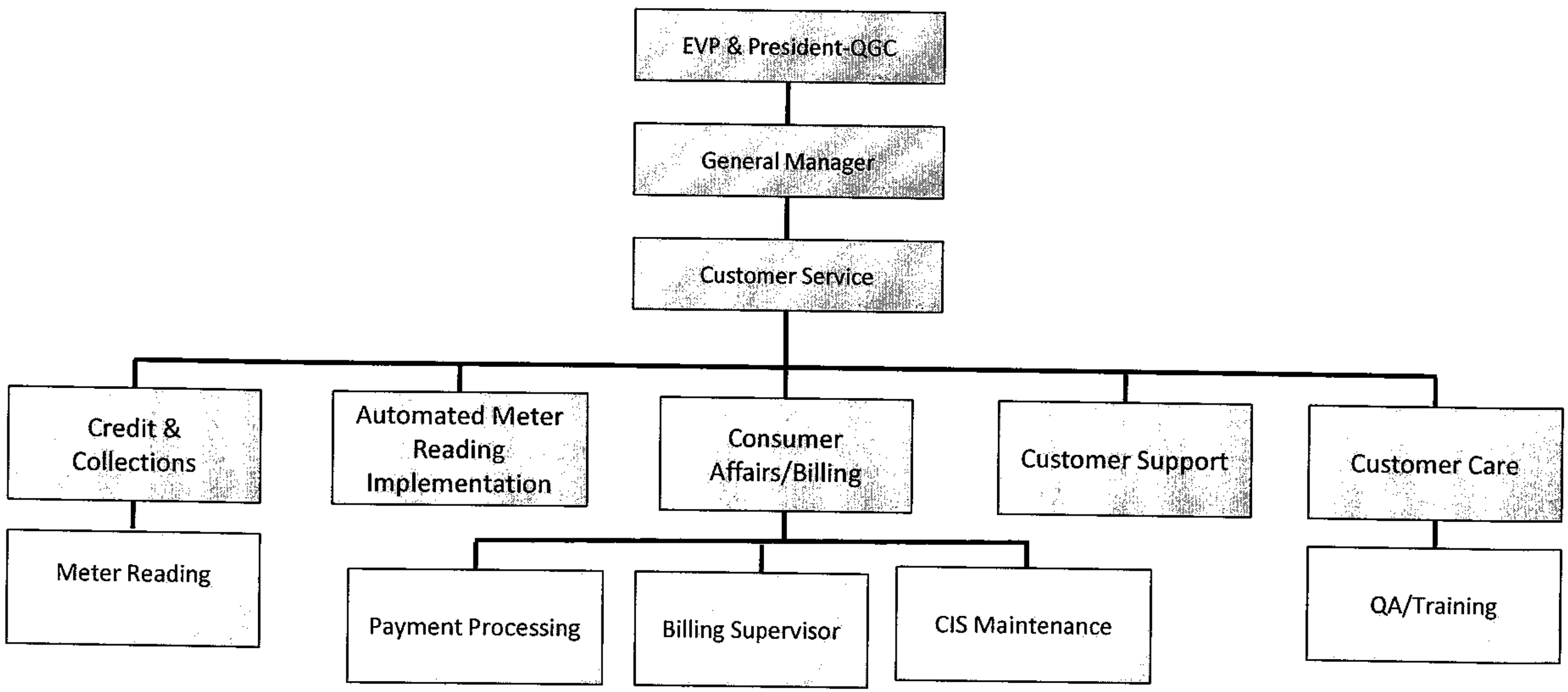
Customer Service - QGC



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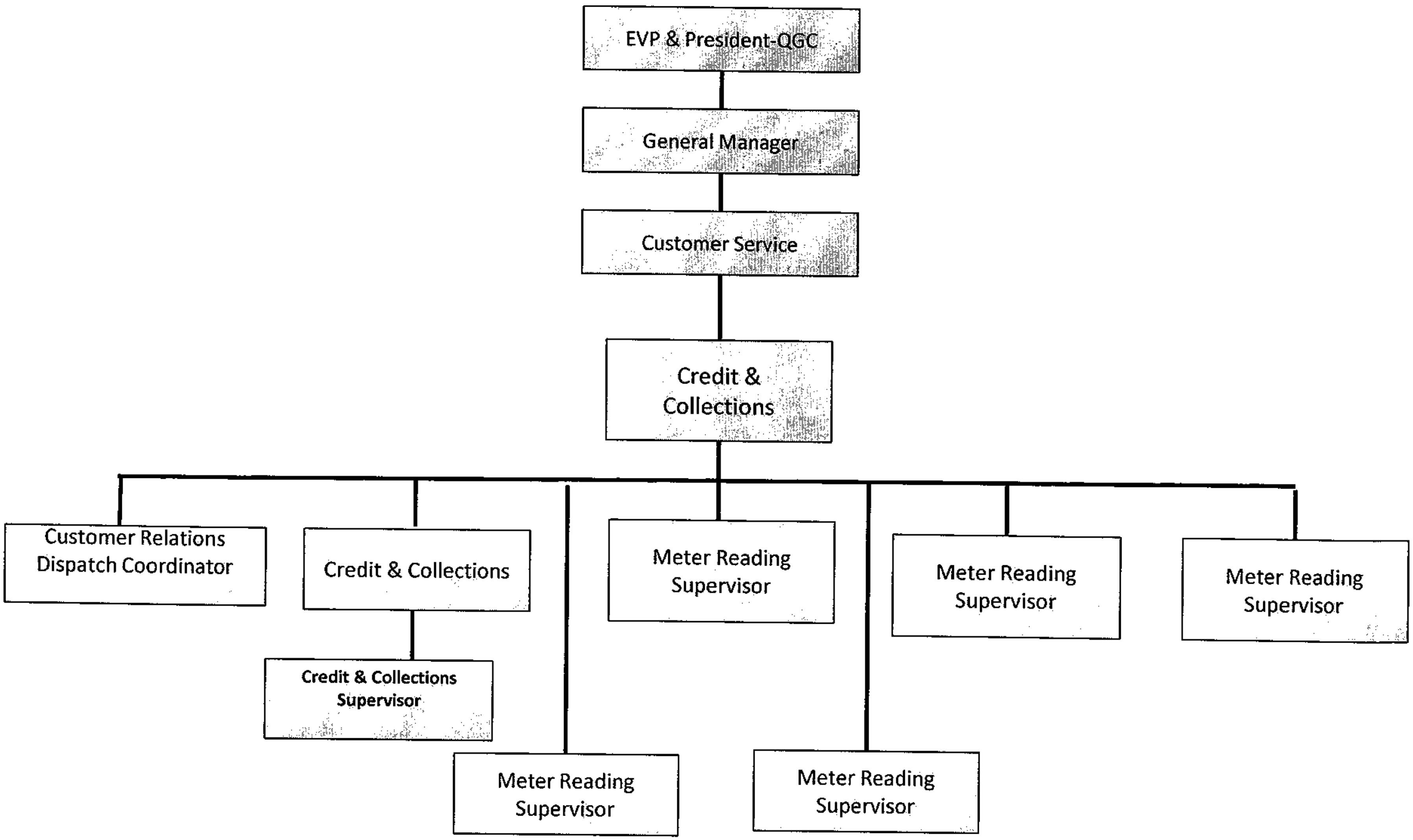
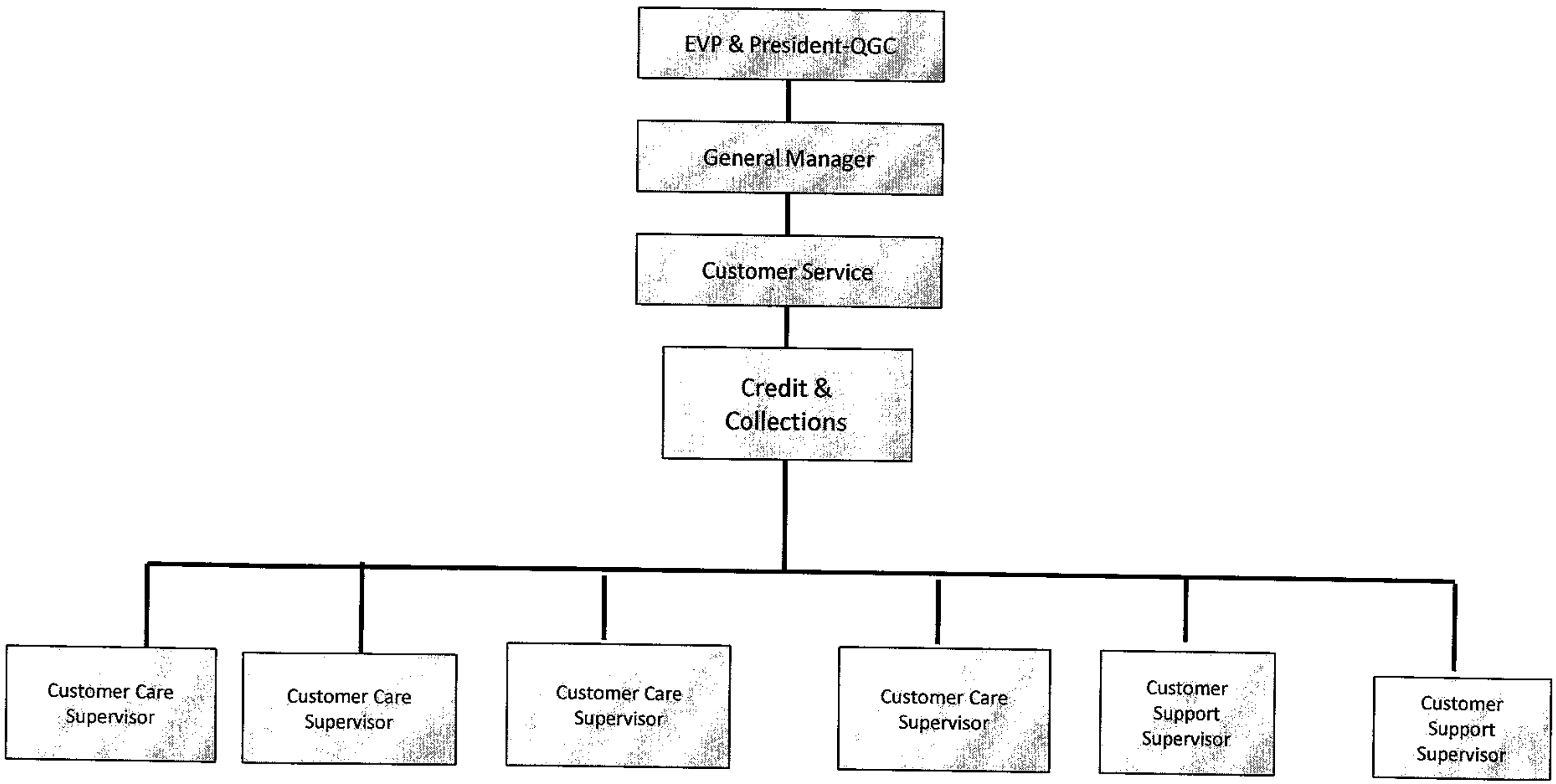
Customer Service - QGC



Customer Service - QGC



W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.20
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.20 After the Merger will any current Questar assets or contracts be transferred outside the post-transaction Dominion Questar entity? Will any Dominion assets or Dominion entities be transferred into the post-transaction Dominion Questar entity? Please explain and identify any regulated or unregulated assets and/or entities moving around post the transaction.

Answer: After the Merger, it is anticipated that all current Questar Gas Company assets and contracts will remain with Questar Gas Company, and will not be transferred to another Dominion entity. Similarly, it is not anticipated that any Dominion assets or Dominion entities will be transferred into Questar Gas Company after the Merger.

After the Merger and subject to negotiation with Dominion Midstream Partners, LP ("Dominion Midstream Partners"), Dominion expects to contribute all or part of Questar Pipeline Company to Dominion Midstream Partners in a financial transaction that will have no impact on the operations, services provided, or rates of Questar Pipeline Company. Dominion owns the general partner and approximately 64% of the limited partnership interests in Dominion Midstream Partners, which is a master limited partnership designed to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets.

Prepared by: Russell J. Singer, Assistant General Counsel, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.22
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.22 Does Dominion plan on merging Dominion Questar with another Dominion entity within the next five years after the proposed Merger?

Answer: There are no current plans to merge Dominion Questar into any Dominion entity within the next five years.

Prepared by: Prepared by: Richard M. Davis, Director - Corporate Finance, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-20)

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.18
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.18 Reference Joint Notice and Application ¶ 58d, p. 25.

a. Please explain if there has been any analysis or studies completed to quantify the potential cost and benefit to ratepayers if all or part of the Questar Pipeline is contributed to Dominion Mainstream.

b. If so, please provide all relevant documents including how costs and benefits to ratepayers were quantified.

c. If any costs will be incurred, please explain when these costs would be expected to show up in rates.

Answer: a.-c. See the responses to WPSC 2.02, 2.02.1, 2.02.2, 2.02.3, 2.02.4, 2.03.2, 2.03.3.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.02
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.02 In response to WPSC CIR 1.20, "After the Merger and subject to negotiation with Dominion Midstream Partners, LP, Dominion expects to contribute all or part of Questar Pipeline Company to Dominion Midstream Partners in a financial transaction that will have no impact on the operations, services provided, or rates of Questar Pipeline Company." Will this planned transfer involve assets that transport gas to current Questar regulated customers? Please explain how Dominion will retain control of Questar Pipeline Company as it sells equity interest to finance the acquisition.

Answer: Yes, the planned transfer will involve assets that transport gas to current Questar Gas customers in Utah and Wyoming. In order to understand how Dominion will retain control of Questar Pipeline Company as it sells equity interests to finance the acquisition, it is important to review both: (1) the exact nature of the proposed acquisition equity financing; and (2) the governance structure of Dominion Midstream Partners, L.P. ("DM").

(1) The equity financing at DM that will finance the acquisition of Questar Pipeline Company will be comprised of the issuance of new Limited Partner equity (in the form of "Limited Partner units") to public equity investors. This will have the effect of diluting somewhat Dominion's existing ~65% ownership of all Limited Partner equity (units) but will have no impact on Dominion's 100% ownership of the DM's General Partner.

(2) DM is a Master Limited Partnership with two kinds of partners; General Partners (100% owned by Dominion) and Limited Partners (currently ~65% owned by Dominion). Except in very limited, rare, and specific instances (as described in more detail in the DM registration statement of Form S-1 that was filed with the Securities and Exchange Commission and declared effective on October 10, 2014), the General Partner exercises **sole control** over every decision at DM including operating and financial decisions. Further, DM's General Partner management is identical to Dominion Resources Inc.'s management as described in the following table:

Position	Dominion Resources, Inc.	DM's General Partner
Chairman and CEO	Thomas F. Farrell II	Thomas F. Farrell II
Executive Vice President & CFO	Mark F. McGettrick	Mark F. McGettrick
Executive Vice President	David A. Christian	David A. Christian

Vice President, Controller & Chief Accounting Officer	Michele L. Cardiff	Michele L. Cardiff
Senior Vice President & General Counsel	Mark O. Webb	Mark O. Webb
Senior Vice President & Treasurer	James R. Chapman	James R. Chapman
Senior Vice President	Carter M. Reid	Carter M. Reid
Senior Vice President	Paul E. Ruppert	Paul E. Ruppert
Senior Vice President	Robert M. Blue	Robert M. Blue

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.02.1
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.02.1 Will Dominion Midstream Partners have separate financing and financing costs from Dominion Questar, Dominion Wexpro companies, and Dominion Questar Gas? Please explain and identify and separate and/or shared financing vehicles.

Answer: DM's financing and financing costs will be completely separate from Dominion Questar, Dominion Wexpro companies, and Dominion Questar Gas. DM has access to external equity financing (via issuance of Limited Partner equity), has access to intercompany lending with Dominion Resources, Inc. for short-term debt financing needs, and has access to external debt financing (bank and bond options) for long-term debt financing needs. None of those financings or financing costs will have any relationship with Dominion Questar, Dominion Wexpro companies, and Dominion Questar Gas.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.02.2
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.02.2 How will Dominion Questar Gas regulated gas customers be protected from any potential adverse consequences arising from this proposed transfer of Questar Pipeline Company assets to Dominion Midstream Partners going forward?

Answer: Dominion is not aware of any potential adverse consequences arising from the proposed transfer of Questar Pipeline Company assets to DM. As previously described, DM's General Partner is wholly owned by Dominion and Dominion retains sole discretion over all financial and operating decisions at DM and therefore Questar Pipeline Company. DM is prudently capitalized and has access to equity and debt capital to support its subsidiaries as needed. Further, after transfer to DM, Questar Pipeline Company will continue to be prudently capitalized and will maintain access to capital markets as a standalone long-term issuer of debt. Dominion intends for current Questar Pipeline Company employees to continue to perform the same services to support day-to-day operations.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.02.3
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.02.3 Will the proposed terms and conditions of contracts and agreements between Questar, Wexpro companies, Questar Gas Company and Questar Pipeline Company change after the sale of Questar Pipeline Company to Dominion Midstream after the merger? Please describe any proposed changes.

Answer: No. The transfer of Questar Pipeline Company to DM will not have any impact on the terms and conditions of existing contracts and agreements between Questar Pipeline Company and its current Questar affiliates.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.02.4
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.02.4 After the Questar Pipeline Company is transferred to Dominion Midstream Partners, please provide a general description of Dominion Midstream Partners and how that legal entity operates and interacts with other Dominion entities including how it plans to operate and interact with the proposed Dominion Questar, Dominion Wexpro companies and Dominion Questar Gas, as proposed.

Answer: DM is a growth-oriented limited partnership formed by Dominion to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets. DM's current assets include a preferred equity interest in the Cove Point LNG LP facility, a common equity interest (100%) in Dominion Carolina Gas Transmission, LLC (a FERC regulated natural gas transportation system in South Carolina and Georgia), and an equity interest (~26%) in Iroquois Gas Transmission System L.P. (a FERC regulated natural gas transportation system in New York and Connecticut). DM's interaction with Dominion Resources, Inc. and affiliates is extensive. As an example, DM's operations are managed by employees of Dominion Resources, Inc. and affiliates.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.03
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.03 Please provide the capital structure of Dominion Questar Corporation before and after the sale of Questar Pipeline Company from Dominion Questar Corporation to Dominion Midstream Partners.

Answer: **Capital structure of Questar Corporation (as of 3/31/2016)**
Short-term debt: $458.5 million
Current portion of long-term debt and capital lease obligation: $1.2 million
Long-term debt and capital lease obligation, less current portion: $992.7 million
Common Shareholders' equity: $1,360.7 million

Capital structure of Dominion Questar Corporation (before contribution of Questar Pipeline Company to Dominion Midstream Partners, L.P. ("DM"))
It is premature to provide a definitive statement as this evaluation is on-going. However, (and subject to on-going evaluation) two of the primary drivers that would result in a change to the U.S. GAAP capital structure of Dominion Questar Corporation are: (1) a "fair-valuing" of assets and liabilities which is required by accounting rules for a transaction of this nature but that given the regulated nature of the preponderance of operations at Questar is not expected to be material; and (2) the allocation of goodwill. However, Dominion has committed that it will not record any portion of the cost to acquire or any goodwill associated with the Merger on Dominion Questar Gas' books and is planning to make the required accounting entries associated with the Merger on that basis. For ratemaking purposes, Dominion expects that Dominion Questar Gas' capital structure will continue to serve as the "reference" balance sheet as it has in previous regulatory proceedings.

Capital structure of Dominion Questar Corporation (after contribution of Questar Pipeline Company to DM)
Please see the response to 2.03.1.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.03.1
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.03.1 What will happen to any debt currently assigned to Questar Pipeline Company after the purchase by Dominion Midstream? What will happen to the capitalization of Dominion Questar Corporation after the purchase of Questar Pipeline Company by Dominion Midstream?

Answer: Questar Pipeline Company's existing long-term debt obligations will transfer with Questar Pipeline Company to DM and remain the obligation of Questar Pipeline Company (to become Dominion Questar Pipeline Company). There will be no change to the structure, pricing/cost, security package, or holders of this debt due to this transfer.

The detailed mechanics of the contribution of Questar Pipeline Company to DM has not been definitively determined at this point. Therefore it is premature to provide a definitive statement of the impact to Dominion Questar's capitalization.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.03.2
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.03.2 Will Dominion Questar Gas customers be negatively impacted by the higher Dominion Questar Corporation equity levels due to the proposed post-merger sale of Questar Pipeline Company?

Answer: In fact, Dominion does not have a definitive view that the equity levels of Dominion Questar Corporation will be "higher" as a result of the contribution of Questar Pipeline Company to DM. Depending on the form of the contribution, said equity levels could be higher, could be lower, or could be unchanged. It is premature for Dominion to make a definitive statement on the topic while a final form of contribution is still being decided. However, Dominion does not expect, regardless of contribution structure, the transaction to have a negative impact in any way on Dominion Questar Gas customers. For ratemaking purposes, Dominion expects that Dominion Questar Gas' capital structure will continue to serve as the "reference" balance sheet as it has in previous regulatory proceedings.

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 2.03.3
Requested by Wyoming Commission Staff
Date of QGC Response May 16, 2016

Intended for Dominion:

WPSC 2.03.3 Please explain the potential impact, advantages and disadvantages to Dominion Questar Gas customers of selling the Questar Pipeline Company to the Dominion Midstream Limited Partnership rather than retaining Questar Pipeline Company under Dominion Questar Corporation.

Answer: Dominion does not expect there to be any disadvantages to Dominion Questar Gas customers as a result of the contribution of Questar Pipeline Company to DM. The operations and services provided by Questar Pipeline Company are not expected to change as a result of the transaction. While not quantifiable at this time, Dominion expects that Dominion Questar Gas customers could stand to benefit over time from having a large, well capitalized parent company which maintains diverse and attractive capital markets access in the bond, equity, and MLP equity markets (the latter access being supported by the contribution of the Questar Pipeline Company business).

Prepared by: Steven D. Ridge, Director, M&A, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-21)

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.52
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.52 Please refer to the Joint Notice and Application, ¶ 27, p. which states "After the Effective Time and subject to negotiation with Dominion Midstream, Dominion expects to contribute all or part of Questar Pipeline to Dominion Midstream in a transaction that will have no impact on the operations, services provided, or rates of Questar Pipeline", and respond to the following:

a. Please provide all analysis, studies or reports that substantiate the business case for the asset contribution plan.
b. Will this "contribution" trigger an ADIT payment and how will that flow into gas transmission rates?
c. How will the price for these contributed assets be set?
d. Who receives the benefit of any price above book value for the contributed value?
e. What will be the expected rate treatment for any value above net book value for the contributed assets?
f. Will gas control operations for interstate pipelines be shared between the entities?
g. Explain the integration of the two system, including the extent operations will be consolidated, including reliability functions.

Answer: a. Please refer to the response to DPU 6.18

b. The asset contribution plan has not been finalized, but to the extent the contribution of Questar Pipeline to Dominion Midstream Partners, L.P. ("Dominion Midstream") would be treated as a sale for tax purposes, the contributor would report tax gain equal to the difference between the fair market value and the tax basis of the assets treated as sold. Questar Pipeline's tax basis in these assets would be increased to reflect the deemed purchase price. The reporting of the tax gain would extinguish any accumulated deferred income tax ("ADIT") balance related to these assets that existed prior to the transaction. We believe that the tax normalization rules as currently administered would require Questar Pipeline to adjust its ADIT balance accordingly. We believe that the ADIT balance adjustment described above is consistent with Federal Energy Regulatory Commission ("FERC") precedent related to sales of property to FERC-jurisdictional partnerships.

Any decision regarding gas transmission rates related to possible changes to ADIT would be made by FERC.

c. The value at which Questar Pipeline will be contributed to Dominion Midstream has yet to be determined and will be subject to the review and approval of the Dominion Midstream Board of Directors.

d. Please refer to the response to WPSC 2.08.

e. Please refer to the response to WPSC 2.08. Any decision regarding gas transmission rate treatment for any value above net book value for the contributed assets ("goodwill") would be made by FERC.

f. There is no plan to share gas control operations between the Questar Interstate pipelines and the Dominion Interstate pipelines at this time.

g. As noted in response to WPSC 1.20, the contribution of Questar Pipeline to Dominion Midstream will be a financial transaction. Please also see the response to WPSC 2.06, note that the pre-merger Dominion entities will not be directly involved in local operations of the Dominion Questar companies. Information provided in response to DPU 4.12 explains the nature of decision making for the Dominion Questar entities – including those decisions that may have an impact on operations. Dominion and Questar do anticipate opportunities for shared knowledge and understanding of best practices among the operating companies. For example, the companies intend to compare approaches and lessons learned with regard to safety, pipeline and storage operations, pipeline integrity, information technology and customer service. These practices can have both direct and indirect bearing on the reliability and quality of services provided to our customers, over time.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-22)

P.S.C.U. Docket No. 16-057-01
Data Request No. 3.03
Requested by Office of Consumer Services
Date of QGC Response June 10, 2016

OCS 3.03 Please describe how the income tax expense of Questar Pipeline will be determined after it is contributed to Dominion Midstream. Address the fact that Dominion Midstream is an MLP and the effect this tax treatment will have on the income tax expense of Questar Pipeline as a separate entity within Dominion Midstream. Provide a copy of the Tax Sharing Agreement between Questar Pipeline and Dominion Midstream, if any. If one has not yet been drafted, then please provide the form of the Tax Sharing Agreement between Dominion Midstream and its other subsidiaries.

Answer: As part of the contribution of Questar Pipeline Company ("Questar Pipeline") to Dominion Midstream Partners, L.P. ("Dominion Midstream"), Questar Pipeline will convert to a single member limited liability company and as a result become a disregarded entity for income tax purposes, and be considered a division of Dominion Midstream.

Dominion Midstream is organized as an MLP. As a pass-through entity for U.S. federal and state income tax purposes, each of its unitholders is responsible for taking into account the unitholder's respective share of Dominion Midstream's items of taxable income, gain, loss and deduction in the preparation of income tax returns. As a pass-through entity not subject to income taxes, there is no tax sharing agreement within Dominion Midstream.

The Federal Energy Regulatory Commission has a policy to permit cost-of-service rates to reflect actual or potential income tax liability for all public utility assets, regardless of the form of ownership. Under this policy, all entities or individuals owning public utility assets would be permitted an income tax allowance, provided that they have an actual or potential income tax liability on that public utility income. Thus, a corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities, provided that they have an actual or potential income tax liability on that income.

Prepared by: Jonathan Bass, Senior Tax Consultant, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-23)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.09
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.09 Please identify the amount of Corporate overhead from Dominion that is anticipated to be allocated to Dominion Questar and Questar Gas.

Answer: As described in the testimony of Witnesses Farrell and Wood, Questar entities will benefit from efficiencies and economies of scale associated with participating in Dominion's centralized services company model. At this time, Dominion and Questar have not completed the process of identifying the specific corporate functions that would be transferred to a services company to yield such benefits. Presented below is a summary description of Dominion's service company model billing method:

Dominion services company model – A combination of direct charges and allocations. Under the services company model, the services company's affiliates are billed at cost. Similar to Questar Corporation, when work is performed for an individual affiliate, services company employees charge hours directly to the affiliate at a standardized hourly rate that includes labor, payroll taxes, and benefits, as well as an estimate for overhead costs necessary to support the service being provided (e.g., administrative and general expenses and infrastructure costs). Any remaining services company costs represent work performed for all affiliates, or specific groups of affiliates (e.g., operating segments), and are billed using methods based on relative attributes of the affiliates. Depending upon the nature of the services company department, these attributes include: headcount, square footage, operations and maintenance costs, number of customers, documents processed, network devices, vehicles, etc.

Prepared by: John Ingram, Director-Accounting, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.10
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.10 Please provide an understanding of the amounts and the method used to allocate corporate overhead changes to the existing operating entities of Dominion Resources.

Answer: Please see the response provided to DPU 2.09 for a summary description of the method used to charge and/or allocate Dominion's services company to its affiliates.

Prepared by: John Ingram, Director-Accounting, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 4.01
Requested by Division of Public Utilities
Date of QGC Response April 27, 2016

DPU 4.01 Please provide a spreadsheet showing a side by side comparison of pre and post-merger shared services costs, those currently allocated to Questar Gas those anticipated to be allocated to Dominion-Questar Gas. Please use data from the last full year and the first projected year..

Answer: A list of shared service costs currently allocated to Questar Gas are shown in DPU 2.05. It is anticipated that Dominion shared services will perform some of the same services that are performed currently by Questar Corporation. The corporate support functions are currently working together towards a plan for integration. At this point in the process, projected costs for the integrated Company going forward have not been quantified.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.40
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.40 Reference the Direct Testimony of David M. Curtis p. 8:21 – 28.

a. If the merger was approved, what common services currently shared between Questar Gas and Questar Corporation will be changed to shared services with Dominion?

b. What would the timeline be for combining any shared services?

Answer:

a. See the responses to DPU 4.01 and OCS 2.15. See also the testimony of Fred G. Wood, pages 10-11.

b. See slide 14 of the Joint Applicants' presentations at the April 28th and 29th technical conferences in Utah and Wyoming respectively.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.15
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Merger Costs, Integration Activities, and Savings

OCS 2.15 Please provide a copy of all integration/transition studies, analyses, and reports that address the organization, activities, staffing, costs, and/or savings to integrate Questar Corporation, Questar Pipeline, and Questar Gas into the Dominion organization structure. Please provide updates to your response as the integration/transition process proceeds.

Answer: As stated in the Joint Application, Dominion plans to operate Questar Gas and Questar Pipeline in the same manner they operate today. See the presentation provided at the April 28, 2016 Utah Technical Conference for a description of and status update on the integration process. See also the response to WPSC 2.05 for organizational charts showing the legal entity structure of Questar Corporation and its subsidiaries within Dominion, as well as how Questar is expected to be incorporated into Dominion's operating segment and leadership structures. These organizational charts also reflect the only staffing changes made to date. There are no other formal studies, analysis, or reports on the integration to date. Updates will be provided as the integration process proceeds.

Prepared by: Karla Haislip, Merger & Acquisition Project Director, Dominion Resources Services, Inc.

W.P.S.C. Docket Nos. 30010-150-GA-16 and 30025-1-GA-16
Data Request No. 1.21
Requested by Wyoming Commission Staff
Date of QGC Response March 24, 2016

WPSC 1.21 Please describe any changes in corporate overhead charges and/or cost allocation from Dominion to the Questar regulated entities and Wexpro after the Merger.

Answer: As described in the testimony of Witnesses Farrell and Wood, Questar entities will benefit from efficiencies and economies of scale associated with participating in Dominion's centralized services company model. At this time, Dominion and Questar have not completed the process of identifying the specific corporate functions that would be transferred to a services company to yield such benefits. Presented below are summary descriptions of Questar Corporation's corporate allocation methodology as compared to Dominion's service company model billing method:

Questar corporate cost allocation – A combination of direct charges and allocations

Questar Corporation's costs are directly assigned, when possible, by charging affiliates an hourly rate that includes overheads. Any remaining general and administrative costs that cannot be directly assigned are allocated to subsidiaries using the "Distrigas" formula – a weighted average distribution among the subsidiaries based on their relative share of Gross Plant, Gross Revenues and Gross Payroll.

Dominion services company model – A combination of direct charges and allocations

Under the services company model, the services company's affiliates are billed at cost. Similar to Questar Corporation, when work is performed for an individual affiliate, services company employees charge hours directly to the affiliate at a standardized hourly rate that includes labor, payroll taxes, and benefits, as well as an estimate for overhead costs necessary to support the service being provided (e.g., administrative and general expenses and infrastructure costs). Any remaining services company costs represent work performed for all affiliates, or specific groups of affiliates (e.g., operating segments), and are billed using methods based on relative attributes of the affiliates. Depending upon the nature of the services company department, these attributes include: headcount, square footage, operations and maintenance costs, number of customers, documents processed, network devices, vehicles, etc.

Prepared by: John Ingram, Director-Accounting, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-24)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.05
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.05 Please identify the amount of Corporate overhead that has been paid by each Questar operating entity as of December 31, 2013, 2014 and 2015.

Answer: See DPU 2.05 Attachment 1.xlsx, DPU 2.05 Attachment 2.xlsx and DPU 2.05 Attachment 3.xlsx for a breakdown of 2013, 2014 and 2015 costs billed from Questar Corporation to its sub-entities. Referring to Attachment 1, Lines 1-58 represent the total expense charged from Questar Corporation to its sub-entities. Columns (C) through (G) are expenses that are not allocated, but directly charged. Columns (H) through (L) are expenses that are allocated. Most costs are allocated using Distrigas, but other allocation methods are also used such as Employee Count, square footage, number of transactions, number of computers, or some other allocation method.

Line 59 represents amounts that were directly recorded to balance sheet accounts, such as labor overhead items, pension contributions and insurance premiums that are later charged to expense or capital accounts through allocations or amortizations.

Prepared by: Mike Rawlins, Manager Accounting, Questar Gas Company

2013 Corporate Charges to Subsidiaries

Line	(A)	(B)	DIRECT CHARGES (C) QFC	(D) QPC	(E) WEX	(F) QGC	(G) Total Direct Charges	ALLOCATED CHARGES (H) QFC	(I) QPC	(J) WEX	(K) QGC	(L) Total Allocated	(M) Total Direct & Allocated
1	1/	Direct Payments to Expense	19,609.49	581,389.12	-	1,974,783.13	2,575,781.74	-	-	-	-	-	2,575,781.74
2	284	Misc Other Income	-	-	-	-	-	-	(791.92)	(267.95)	(4,433.85)	(5,493.72)	(5,493.72)
3	400	Labor	84,317.66	3,279,385.38	394,674.29	4,010,250.30	7,768,627.63	533.13	4,453,456.61	2,153,720.53	9,853,629.44	16,461,339.71	24,229,967.34
4	402	Incentive Wages	-	266.18	-	234,634.50	234,900.68	-	1,999,585.59	1,631,258.34	3,005,683.08	6,636,527.00	6,871,427.68
5	403	Share-based Compensation	-	-	-	-	-	-	1,589,501.98	1,296,712.87	2,389,264.67	5,275,479.52	5,275,479.52
6	410	Travel	9,025.37	50,917.25	41,566.29	36,114.14	137,623.05	1.14	115,597.05	84,927.59	196,327.36	396,853.14	534,476.19
7	413	Training	-	2,180.10	10,803.74	725.00	13,708.84	4.00	28,957.76	13,737.47	69,292.25	111,991.48	125,700.32
8	414	Meals-Travel/Entertain	991.44	6,093.95	429.01	12,473.25	19,987.65	0.69	51,207.28	36,643.59	87,483.45	175,335.01	195,322.66
9	416	Meals-OnPremise, OT	-	-	-	591.75	591.75	0.14	12,680.64	7,239.18	30,172.93	50,092.90	50,684.65
10	453	Computer Software	-	-	70,623.24	415.80	71,039.04	67.76	246,174.38	100,701.14	742,094.99	1,089,038.27	1,160,077.31
11	459	Computer Hardware	-	2,128.39	-	7.66	2,136.05	-	9,010.78	4,670.57	29,058.85	42,740.20	44,876.25
12	460	Warehouse Supplies	-	1,307.46	-	33,177.21	34,484.67	-	1,702.32	1,322.77	2,563.85	5,588.95	40,073.62
13	461	Supplies and Equipment	14,798.51	650,993.76	44,747.95	(2,782,386.24)	(2,071,846.02)	6.24	104,176.93	51,112.71	448,915.70	604,211.58	(1,467,634.44)
14	482	Communication Charges	-	-	-	-	-	-	349,463.22	285,073.85	525,346.11	1,159,883.17	1,159,883.17
15	531	Advertising	-	-	-	-	-	-	2,366.75	1,940.10	3,543.54	7,850.39	7,850.39
16	546	Consultants/Contracted Svcs	-	91,257.28	571,098.77	161,714.33	824,070.38	2.06	402,242.98	286,887.53	1,013,528.72	1,702,661.29	2,526,731.67
17	547	Investor Relations	-	-	-	-	-	-	157,539.56	128,520.49	236,806.07	522,866.12	522,866.12
18	560	Assoc Company Labor	-	-	-	-	-	20.48	72,500.54	43,355.76	156,364.45	272,241.23	272,241.23
19	561	Assoc Company Labor Ovhd	-	-	-	-	-	6.09	21,394.00	11,659.49	44,565.76	77,625.33	77,625.33
20	562	Assoc Company Vehicle Clrg	-	-	-	-	-	-	1,683.00	503.26	3,373.92	5,560.18	5,560.18
21	565	Assoc Company Other	-	-	-	-	-	-	167,059.48	140,139.88	241,588.84	548,788.20	548,788.20
22	568	Assoc Company G&A	-	-	-	-	-	-	1,113,909.50	838,735.45	1,870,706.59	3,823,351.54	3,823,351.54
23	610	Rent	-	-	244,138.78	-	244,138.78	-	2,346,116.88	1,613,570.40	2,448,243.54	6,407,930.82	6,652,069.60
24	611	Questar Center Parking	-	-	28,385.83	-	28,385.83	-	48,082.68	38,279.64	75,200.47	161,562.79	189,948.62
25	619	Contributions - Noncharitable	-	-	-	299.45	299.45	-	-	-	-	-	299.45
26	620	Contributions and Donations	-	-	-	-	-	-	(454.93)	(250.11)	(994.55)	(1,699.59)	(1,699.59)
27	621	Director Fees & Meetings	-	-	-	-	-	-	544,897.10	444,526.08	819,063.72	1,808,486.90	1,808,486.90
28	622	Director Expenses	-	-	-	-	-	-	17,969.47	14,659.46	27,010.86	59,639.79	59,639.79
29	628	Dues, Publications, Subscriptio	-	113.97	10,271.81	99.75	10,485.53	0.11	83,596.33	66,555.43	136,202.74	286,354.61	296,840.14
30	629	Postage & Express	-	-	-	392,204.57	392,204.57	-	6,790.42	4,794.26	24,570.73	36,155.41	428,359.98
31	635	Licenses, Permits and Fees	40.00	8,666.57	9,650.21	6,296.97	24,653.75	0.25	18,101.11	13,709.34	28,994.13	60,804.84	85,458.59
32	641	Regulatory Fees/Expense	-	-	-	-	-	-	2,071.97	887.51	5,360.30	8,319.78	8,319.78
33	642	Insurance & Bonding	-	(47,108.22)	899,749.53	5,783.19	858,424.50	-	6,283.16	5,125.79	9,444.55	20,853.51	879,278.01
34	644	Bad Debts	-	-	-	-	-	-	292.67	238.76	439.93	971.37	971.37
35	645	Third Party Claims	-	-	-	-	-	-	386.03	314.92	580.26	1,281.20	1,281.20
36	650	Long-term Disability	-	7,500.00	-	12,052.00	19,552.00	-	-	-	-	-	19,552.00
37	651	Recognition Outstanding Servic	-	-	-	-	-	-	850.63	490.54	1,539.25	2,880.42	2,880.42
38	652	Employee Benefits-WC&GPL	-	-	11,158.22	-	11,158.22	-	-	-	-	-	11,158.22
39	653	Employee Benefits-Medical	-	-	1,624,991.57	(1,500.00)	1,623,491.57	-	115.64	48.64	302.02	466.30	1,623,957.87
40	654	Employee Benefits-Life Insur	-	-	17,374.91	-	17,374.91	-	-	-	-	-	17,374.91
41	655	Employee Benefits-Retirement	-	42,119.75	3,063,857.79	108,548.65	3,214,526.19	-	(77,790.52)	(32,717.78)	(203,170.54)	(313,678.84)	2,900,847.35
42	656	Employee Benefits-Empl Invest	-	-	-	-	-	-	39,555.16	16,636.43	103,308.76	159,500.35	159,500.35
43	657	Employee Benefits-Miscellanec	-	-	17,001.51	-	17,001.51	-	-	-	-	-	17,001.51
44	666	Depreciation	-	-	-	-	-	-	310,502.56	253,307.43	466,732.86	1,030,542.85	1,030,542.85
45	673	Bank Service Charge	-	-	75,026.91	-	75,026.91	-	74,726.30	60,961.58	112,325.06	248,012.94	323,039.85
46	677	Interest Expense - Assoc Comp.	-	-	19,709.28	-	19,709.28	-	-	-	-	-	19,709.28
47	687	Amortization of Debt Expense	-	-	-	-	-	-	194,398.12	158,589.64	292,210.12	645,197.88	645,197.88
48	710	Federal Income Tax	(2,400,000.00)	16,800,000.00	32,505,853.00	(1,373,817.00)	45,532,036.00	-	-	-	-	-	45,532,036.00
49	715	State Income Tax	(24,115.00)	138,073.00	1,860,532.00	(2,370,628.20)	(396,138.20)	-	-	-	-	-	(396,138.20)
50	749	Property Tax	-	-	-	-	-	-	18,193.63	15,451.67	26,426.12	60,071.42	60,071.42
51	850	Garage Vehicles & Equip	-	8,732.52	-	129,424.44	138,156.96	0.09	17,885.27	4,694.84	44,968.33	67,548.52	205,705.48
52	902	Information Technology	-	-	-	-	-	-	(12,337.41)	(6,313.96)	(39,805.93)	(58,457.30)	(58,457.30)
53	920	Labor Overhead	79,467.94	3,150,290.63	380,749.22	3,823,260.27	7,433,768.06	512.47	4,273,128.58	2,061,723.00	9,461,401.99	15,796,766.04	23,230,534.10
54	927	Vehicle Clearing	2,724.83	469,629.33	13,185.96	546,389.87	1,031,929.99	-	35,737.73	9,991.66	105,825.62	151,555.01	1,183,485.00
55	984	Company Services-Other	-	-	84,192.51	-	84,192.51	-	151,971.12	123,977.77	228,435.84	504,384.73	588,577.24
56	985	Transfer to Affiliates	-	7,975.52	3,853.38	23,037.66	34,866.56	-	-	-	-	-	34,866.56
57	989	Clearing Credits	-	-	-	(1,198,883.98)	(1,198,883.98)	-	-	-	-	-	(1,198,883.98)
58		Total Expense Charged to Subsidiaries	(2,213,139.76)	25,251,911.94	42,003,625.71	3,785,068.47	68,827,466.36	1,154.65	19,000,488.11	11,987,847.55	35,120,492.93	66,109,983.24	134,937,449.60
59	2/	Direct Payments to Bal Sheet	1,378.18	18,790,385.59	-	46,068,629.01	64,860,392.78						

1/ Amounts that are paid by corporate departments but are recorded directly on the subsidiaries books as expense rather than allocated, such as outside auditor fees, legal fees, and bank fees .
2/ Direct payments to balance sheet accounts, such as labor overhead items, pension contributions, and insurance premiums that later are charged to expense or capital accounts through other allocations or amortizations.

	2014 (A)	Corporate Charges to Subsidiaries (B)	DIRECT CHARGES (C)	(D)	(E)	(F)	(G)	ALLOCATED CHARGES (H)	(I)	(J)	(K)	(L)	(M)
		Transactions	QFC	QPC	WEX	QGC	Total Direct Charges	QFC	QPC	WEX	QGC	Total Allocated	Total Direct & Allocated
1		1/ Direct Payments to Expense	110,937.79	966,610.54	-	1,827,578.45	2,905,126.78	-	-	-	-	-	2,905,126.78
2	284	Misc Other Income	-	-	-	-	-	(601.97)	(32,752.49)	(31,182.84)	(56,618.15)	(121,155.44)	(121,155.44)
3	400	Labor	645,462.02	3,457,636.48	434,564.21	4,490,111.30	9,027,774.01	44,455.27	4,313,949.59	2,362,903.48	10,004,923.83	16,726,232.17	25,754,006.18
4	402	Incentive Wages	-	16,597.23	-	151,249.85	167,847.08	40,935.11	2,130,170.26	2,077,649.75	3,474,849.89	7,723,605.00	7,891,452.08
5	403	Share-based Compensation	-	-	-	-	-	31,690.20	1,649,086.40	1,608,427.27	2,690,079.67	5,979,283.55	5,979,283.55
6	410	Travel	75,478.63	79,242.28	62,029.90	32,745.50	249,496.31	1,711.16	109,170.79	90,269.58	199,978.84	401,130.37	650,626.68
7	413	Training	-	16,377.11	16,901.92	2,594.54	35,873.57	347.73	35,672.98	19,613.37	85,319.84	140,953.92	176,827.49
8	414	Meals-Travel/Entertain	14,250.69	5,981.22	184.35	17,349.19	37,765.45	357.26	25,832.41	18,073.51	52,771.56	97,034.73	134,800.18
9	416	Meals-OnPremise, OT	95.64	1,338.02	-	606.55	2,040.21	141.69	12,375.52	9,338.25	25,925.89	47,781.35	49,821.56
10	453	Computer Software	-	3,880.34	83,550.31	8,359.75	95,790.40	2,525.23	236,425.65	100,076.34	657,211.87	996,239.08	1,092,029.48
11	459	Computer Hardware	-	34,793.08	36,685.64	209,736.22	281,214.94	15.44	28,176.41	15,558.02	92,898.57	136,648.45	417,863.39
12	460	Warehouse Supplies	-	9,418.58	-	64,220.00	73,638.58	13.67	841.83	741.63	1,520.42	3,117.56	76,756.14
13	461	Supplies and Equipment	158,683.80	358,378.87	139,300.18	(4,531,635.71)	(3,875,272.86)	2,572.79	185,211.26	139,673.16	550,275.20	877,732.41	(2,997,540.45)
14	482	Communication Charges	271.38	-	-	462.90	734.28	6,638.13	345,442.88	336,920.73	563,516.94	1,252,518.68	1,253,252.96
15	531	Advertising	181.69	-	-	-	181.69	65.62	3,434.25	3,369.47	5,583.70	12,453.04	12,634.73
16	546	Consultants/Contracted Svcs	7,593.85	148,769.84	888,215.38	272,507.75	1,317,086.82	15,394.01	498,613.82	372,216.25	1,329,682.15	2,215,906.23	3,532,993.05
17	547	Investor Relations	-	-	-	-	-	2,223.18	115,689.21	112,836.82	188,718.54	419,467.75	419,467.75
18	560	Assoc Company Labor	-	-	-	-	-	369.62	37,658.54	15,142.96	92,853.93	146,025.06	146,025.06
19	561	Assoc Company Labor Ovhd	-	-	-	-	-	122.39	13,525.87	5,281.86	31,673.77	50,603.89	50,603.89
20	562	Assoc Company Vehicle Clrg	-	-	-	-	-	-	1,052.68	277.03	2,004.94	3,334.65	3,334.65
21	565	Assoc Company Other	-	-	-	-	-	1,863.58	126,735.12	125,431.44	197,680.80	451,710.94	451,710.94
22	568	Assoc Company G&A	-	-	-	-	-	14,732.81	928,745.87	818,385.50	1,716,548.26	3,478,412.44	3,478,412.44
23	610	Rent	-	166.25	540.00	-	706.25	18,351.52	2,260,522.89	1,705,114.69	2,446,609.28	6,430,598.38	6,431,304.63
24	611	Questar Center Parking	-	-	1,020.00	-	1,020.00	888.79	47,746.54	45,280.88	80,493.09	174,409.29	175,429.29
25	621	Director Fees & Meetings	-	-	-	-	-	9,853.18	512,737.01	500,095.19	836,404.56	1,859,089.94	1,859,089.94
26	622	Director Expenses	-	-	-	-	-	318.25	16,560.77	16,152.46	27,014.83	60,046.31	60,046.31
27	628	Dues, Publications, Subscripti	-	-	71,367.88	-	71,367.88	1,999.27	115,020.94	108,781.43	191,840.14	417,641.77	489,009.65
28	629	Postage & Express	-	53.88	-	485,068.21	485,122.09	83.50	6,473.64	5,185.71	26,382.51	38,125.36	523,247.45
29	635	Licenses, Permits and Fees	8,051.99	2,331.73	5,007.94	13,126.59	28,518.25	239.41	19,002.69	16,254.39	34,465.27	69,961.76	98,480.01
30	641	Regulatory Fees/Expense	-	995.00	-	750.00	1,745.00	-	3,577.75	1,558.74	10,278.81	15,415.30	17,160.30
31	642	Insurance & Bonding	(425.89)	(109,930.47)	856,889.82	(61,133.72)	685,399.74	80.13	4,169.62	4,066.81	6,801.71	15,118.27	700,518.01
32	644	Bad Debts	-	-	-	-	-	1.39	72.13	70.35	117.67	261.54	261.54
33	650	Long-term Disability	-	7,500.00	-	12,852.00	20,352.00	-	-	-	-	-	20,352.00
34	651	Recognition Outstanding Serv	-	-	-	-	-	30.06	1,986.55	1,747.14	3,739.73	7,503.48	7,503.48
35	652	Employee Benefits-WC&GPL	-	-	10,896.14	-	10,896.14	-	-	-	-	-	10,896.14
36	653	Employee Benefits-Medical	-	-	2,121,436.91	-	2,121,436.91	-	23.11	10.07	66.42	99.60	2,121,536.51
37	654	Employee Benefits-Life Insur	-	-	11,455.33	-	11,455.33	-	-	-	-	-	11,455.33
38	655	Employee Benefits-Retiremer	-	40,643.82	2,235,829.68	110,038.43	2,386,511.93	-	(51,565.41)	(22,468.94)	(148,230.36)	(222,264.71)	2,164,247.22
39	656	Employee Benefits-Empl Inve	-	-	-	-	-	-	50,449.62	21,982.75	145,022.90	217,455.27	217,455.27
40	657	Employee Benefits-Miscellan	-	(2,842.84)	14,364.19	-	11,521.35	73.96	3,848.68	3,753.79	6,278.18	13,954.61	25,475.96
41	666	Depreciation	-	-	-	-	-	8,454.86	439,971.60	429,123.86	717,705.66	1,595,255.97	1,595,255.97
42	673	Bank Service Charge	180.00	-	92,617.41	-	92,797.41	2,309.18	120,164.55	117,201.83	196,018.96	435,694.52	528,491.93
43	677	Interest Expense - Assoc Com	-	-	5,191.55	-	5,191.55	-	-	-	-	-	5,191.55
44	679	Interest Expense - Miscellane	-	-	-	-	-	-	81.78	69.50	118.65	269.93	269.93
45	687	Amortization of Debt Expense	-	-	-	-	-	3,649.70	189,921.93	185,239.30	309,811.00	688,621.92	688,621.92
46	710	Federal Income Tax	(4,900,435.00)	25,390,398.00	68,160,022.00	(21,142,715.00)	67,507,270.00	-	-	-	-	-	67,507,270.00
47	715	State Income Tax	(11,478.00)	1,151,591.38	1,836,805.62	(2,205,881.00)	771,038.00	-	-	-	-	-	771,038.00
48	749	Property Tax	-	-	-	-	-	-	(5,687.23)	(4,833.84)	(8,253.60)	(18,774.67)	(18,774.67)
49	850	Garage Vehicles & Equip	-	-	-	131,686.15	131,686.15	(69.07)	10,685.02	(2,579.49)	25,482.23	33,518.69	165,204.84
50	902	Information Technology	-	-	-	-	-	-	(2,624.04)	(1,446.50)	(8,952.58)	(13,023.12)	(13,023.12)
51	920	Labor Overhead	493,165.81	2,634,969.29	329,632.70	3,357,951.17	6,815,718.97	33,470.69	3,228,821.60	1,766,599.08	7,527,925.58	12,556,816.95	19,372,535.92
52	927	Vehicle Clearing	4,121.51	368,575.07	11,902.19	636,331.61	1,020,930.38	242.85	30,609.21	8,603.37	95,288.60	134,744.03	1,155,674.41
53	984	Company Services-Other	-	-	79,589.09	-	79,589.09	3,938.37	204,943.84	199,890.84	334,315.57	743,088.63	822,677.72
54	985	Transfer to Affiliates	52.35	560,862.39	41,185.96	363,811.95	965,912.65	-	-	-	-	-	965,912.65
55	989	Clearing Credits	-	-	-	(1,166,435.58)	(1,166,435.58)	-	-	-	-	-	(1,166,435.58)
56			(3,393,811.74)	35,144,337.09	77,547,186.30	(16,918,662.90)	92,379,048.75	249,488.95	17,972,573.63	13,306,457.00	34,764,145.28	66,292,664.85	158,671,713.60
57		2/ Direct Payments to Bal Sheet	18,058.71	15,661,450.59	-	39,873,823.58	55,553,332.88						

1/ Amounts that are paid by corporate departments but are recorded directly on the subsidiaries books as expense rather than allocated, such as outside auditor fees, legal fees, and bank fees .

2/ Direct payments to balance sheet accounts, such as labor overhead items, pension contributions, and insurance premiums that later are charged to expense or capital accounts through other allocations or amortizations.

	2015	Corporate Charges to Subsidiaries	DIRECT CHARGES					ALLOCATED CHARGES					
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line		Transactions	QFC	QPC	WEX	QGC	Total Direct Charges	QFC	QPC	WEX	QGC	Total Allocated	Total Direct & Allocated
	1/	Direct Payments to Expense	138,869.16	1,143,170.80	-	2,044,598.93	3,326,638.89	-	-	-	-	-	3,326,638.89
1	284	Misc Other Income	-	-	-	-	-	264.20	12,216.69	12,350.32	17,355.24	42,186.45	42,186.45
2	324	Misc Expense Reductions	-	-	-	-	-	367.94	18,405.47	14,570.10	29,663.04	63,006.55	63,006.55
3	400	Labor	647,096.12	3,476,043.85	535,417.27	4,960,627.86	9,619,185.10	72,027.32	5,168,153.06	2,918,504.22	11,061,481.50	19,220,166.10	28,839,351.20
4	402	Incentive Wages	-	8,116.87	-	27,095.85	35,212.72	31,754.80	1,565,624.95	1,537,272.46	2,535,847.44	5,670,499.65	5,705,712.37
5	403	Share-based Compensation	-	-	-	-	-	32,252.63	1,590,169.88	1,561,372.89	2,575,602.93	5,759,398.33	5,759,398.33
6	410	Travel	95,429.10	56,416.37	53,065.23	30,290.53	235,201.23	1,806.75	100,945.12	86,237.92	187,431.14	376,420.93	611,622.16
7	413	Training	-	7,788.40	8,553.43	2,960.80	19,302.63	574.14	47,477.83	32,910.50	110,232.11	191,194.58	210,497.21
8	414	Meals-Travel/Entertain	16,652.52	5,147.73	414.06	26,863.05	49,077.36	428.47	25,787.96	19,417.53	55,060.08	100,694.04	149,771.40
9	416	Meals-OnPremise, OT	-	95.53	8.70	1,280.85	1,385.08	208.61	16,702.13	12,409.74	33,930.44	63,250.92	64,636.00
10	453	Computer Software	481.94	3,144.82	63,623.81	42,450.81	109,701.38	7,081.69	399,383.41	178,516.01	1,075,941.06	1,660,922.17	1,770,623.55
11	459	Computer Hardware	5,905.99	51,465.03	46,926.24	342,020.76	446,318.02	193.76	34,716.87	23,518.07	99,240.41	157,669.12	603,987.14
12	460	Warehouse Supplies	-	21,812.74	-	38,690.97	60,503.71	61.34	1,901.34	2,904.41	5,413.72	10,280.81	70,784.52
13	461	Supplies and Equipment	97,340.29	335,572.10	109,925.67	(5,054,614.41)	(4,511,776.35)	1,668.88	144,137.77	123,184.46	429,337.15	698,328.25	(3,813,448.10)
14	480	Natural Gas	-	-	-	-	-	(0.00)	(0.01)	(0.01)	(0.02)	(0.04)	(0.04)
15	482	Communication Charges	341.28	-	-	-	341.28	1,447.85	73,198.68	71,130.70	121,618.91	267,396.13	267,737.41
16	483	Power, Sewer, Water	-	-	-	-	-	92.09	4,540.57	4,458.35	7,354.38	16,445.40	16,445.40
17	531	Advertising	-	-	-	-	-	59.41	2,929.28	2,876.24	4,744.57	10,609.50	10,609.50
18	546	Consultants/Contracted Svcs	-	12,499.06	824,884.35	298,580.83	1,135,964.24	14,335.68	906,717.83	787,184.83	1,917,560.59	3,625,798.94	4,761,763.18
19	547	Investor Relations	-	-	-	-	-	1,807.61	89,121.77	87,507.83	144,350.79	322,788.00	322,788.00
20	560	Assoc Company Labor	-	-	-	-	-	(3.51)	(251.55)	(219.79)	(479.54)	(954.39)	(954.39)
21	561	Assoc Company Labor Ovhd	-	-	-	-	-	(0.34)	(71.04)	(40.89)	(178.92)	(291.19)	(291.19)
22	562	Assoc Company Vehicle Clrg	-	-	-	-	-	3.22	79.89	37.50	190.88	311.48	311.48
23	565	Assoc Company Other	-	-	-	-	-	204.73	11,083.13	11,306.71	17,613.90	40,208.47	40,208.47
24	610	Rent	-	360.00	405.00	-	765.00	19,297.47	2,228,924.61	1,853,896.21	2,320,927.84	6,423,046.13	6,423,811.13
25	611	Questar Center Parking	-	-	1,155.00	-	1,155.00	934.88	47,382.72	45,360.21	79,256.42	172,934.23	174,089.23
26	621	Director Fees & Meetings	-	-	-	-	-	10,515.46	518,449.59	509,060.79	839,734.36	1,877,760.19	1,877,760.19
27	622	Director Expenses	-	-	-	-	-	325.20	16,033.59	15,743.23	25,969.65	58,071.66	58,071.66
28	626	Group Entertainment/Dinners	-	-	-	-	-	342.79	16,900.63	16,594.57	27,374.01	61,212.00	61,212.00
29	628	Dues, Publications, Subscriptions	479.40	-	38,201.79	-	38,681.19	2,351.23	128,722.55	121,815.71	220,322.12	473,211.62	511,892.81
30	629	Postage & Express	-	225.00	-	533,137.24	533,362.24	128.48	7,689.01	6,790.70	22,662.47	37,270.65	570,632.89
31	635	Licenses, Permits and Fees	229.00	820,547.33	3,484.25	16,495.62	840,756.20	435.79	25,086.85	21,110.60	46,147.12	92,780.36	933,536.56
32	641	Regulatory Fees/Expense	-	-	-	949.40	949.40	1.73	130.47	110.36	255.44	498.00	1,447.40
33	642	Insurance & Bonding	(795.14)	(109,387.24)	832,814.83	(70,627.97)	652,004.48	61.84	3,048.88	2,993.67	4,938.28	11,042.66	663,047.14
34	644	Bad Debts	-	-	-	-	-	20.86	1,028.25	1,009.63	1,665.45	3,724.18	3,724.18
35	645	Third Party Claims	-	-	837.90	-	837.90	-	-	-	-	-	837.90
36	650	Long-term Disability	-	7,500.00	28,027.79	12,852.00	48,379.79	-	-	-	-	-	48,379.79
37	651	Recognition Outstanding Service E	-	175.00	-	-	175.00	37.66	1,835.86	1,573.45	3,203.04	6,650.00	6,825.00
38	652	Employee Benefits-WC&GPL	-	-	21,794.00	-	21,794.00	-	-	-	-	-	21,794.00
39	653	Employee Benefits-Medical	-	-	2,556,055.12	-	2,556,055.12	-	9.08	4.08	25.39	38.55	2,556,093.67
40	654	Employee Benefits-Life Insur	-	-	16,861.17	-	16,861.17	-	-	-	-	-	16,861.17
41	655	Employee Benefits-Retirement	-	40,716.47	3,315,252.62	107,662.70	3,463,631.79	-	(50,847.77)	(22,842.38)	(142,217.31)	(215,907.46)	3,247,724.33
42	656	Employee Benefits-Empl Invest Pla	-	-	-	-	-	-	37,900.30	17,025.98	106,004.23	160,930.51	160,930.51
43	657	Employee Benefits-Miscellaneous	-	25.00	47,345.67	37.40	47,408.07	233.23	30,947.69	20,032.02	73,030.37	124,243.31	171,651.38
44	659	Deferred Comp (Non-Qualified)	-	-	(8.72)	-	(8.72)	-	-	-	-	-	(8.72)
45	666	Depreciation	-	-	-	-	-	13,776.45	679,831.89	660,601.87	1,100,860.97	2,455,071.19	2,455,071.19
46	673	Bank Service Charge	-	-	76,371.92	-	76,371.92	1,521.98	75,040.28	73,682.29	121,542.22	271,786.77	348,158.69
47	677	Interest Expense - Assoc Company	-	-	103,783.98	-	103,783.98	-	-	-	-	-	103,783.98
48	679	Interest Expense - Miscellaneous	-	-	-	-	-	(1.24)	(65.89)	(67.73)	(104.23)	(239.10)	(239.10)
49	687	Amortization of Debt Expense	1,838.61	90,956.17	(240,183.95)	147,389.17	0.00	4,173.59	205,772.67	202,046.26	333,290.62	745,283.13	745,283.13
50	710	Federal Income Tax	(528,000.00)	29,714,000.00	62,506,000.00	24,876,000.00	116,568,000.00	-	-	-	-	-	116,568,000.00
51	715	State Income Tax	17,933.00	2,379,403.84	4,005,486.16	(3,783,783.00)	2,619,040.00	-	-	-	-	-	2,619,040.00
52	731	Sales Tax	-	-	-	-	-	206.51	10,253.85	10,014.29	16,687.44	37,162.09	37,162.09
53	735	Telecomm Gross Receipts Tax	-	-	-	-	-	103.66	5,145.29	5,026.26	8,371.96	18,647.17	18,647.17
54	749	Property Tax	-	-	-	-	-	547.07	28,475.25	28,981.85	45,278.90	103,283.06	103,283.06
55	850	Garage Vehicles & Equip	-	450.50	-	97,615.31	98,065.81	77.13	11,628.49	2,853.01	27,771.77	42,330.40	140,396.21
56	902	Information Technology	-	-	-	-	-	(0.35)	(64.60)	(44.02)	(182.62)	(291.59)	(291.59)
57	920	Labor Overhead	551,852.58	2,976,915.43	459,059.66	4,152,318.01	8,140,145.68	60,912.98	4,380,028.17	2,467,011.78	9,392,076.65	16,300,029.58	24,440,175.26
58	927	Vehicle Clearing	5,796.76	354,376.97	8,006.89	546,479.34	914,659.96	696.49	54,200.48	26,964.59	138,442.29	220,303.85	1,134,963.81
59	930	Communication Chargeback	-	-	-	-	-	(128.15)	(6,099.54)	(6,078.61)	(9,510.57)	(21,816.87)	(21,816.87)
60	949	Office Building Clearing	-	-	-	-	-	-	2,922.06	-	5,024.05	7,946.11	7,946.11
61	953	Other Clearing	-	-	-	-	-	5.04	248.73	244.23	402.87	900.88	900.88
62	969	Warehouse Overhead	-	-	-	-	-	10.49	442.27	507.11	1,355.29	2,315.17	2,315.17
63	984	Company Services-Other	-	-	18,432.45	-	18,432.45	4,639.71	228,754.07	224,611.48	370,513.66	828,518.91	846,951.36
64	985	Transfer to Affiliates	-	177,191.97	451,302.22	1,054,972.47	1,683,466.66	-	-	-	-	-	1,683,466.66
65	989	Clearing Credits	-	-	-	(1,095,686.24)	(1,095,686.24)	-	-	-	-	-	(1,095,686.24)
66			1,051,450.61	41,574,729.74	75,893,304.51	29,356,658.28	147,876,143.14	287,865.25	18,902,726.78	13,794,043.56	35,610,431.94	68,595,067.54	216,471,210.68
67	2/	Direct Payments to Bal Sheet	5,816.52	21,052,196.21	-	55,752,596.85	76,810,609.58						

1/ Amounts that are paid by corporate departments but are recorded directly on the subsidiaries books as expense rather than allocated, such as outside auditor fees, legal fees, and bank fees .
2/ Direct payments to balance sheet accounts, such as labor overhead items, pension contributions, and insurance premiums that later are charged to expense or capital accounts through other allocations or amortizations.

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.05U
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 2.05U Please identify the amount of Corporate overhead that has been paid by each Questar operating entity as of December 31, 2013, 2014 and 2015.

Answer: DPU 2.05 Attachment 1.xlsx, has been updated to correct the totals in Columns L and M, lines 1-57, for 2013 in the attached file named DPU 2.05U Attachment 1.

Prepared by: Kelly Mendenhall, General Manager Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.06
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.06 Please explain the specific costs that are included in the corporate overhead charge and how the overhead charges are allocated to the operating entities.

Answer: See the response to DPU 2.05 for costs included in the corporate overhead charge. Costs are directly assigned whenever possible. All remaining costs are allocated using one of the following methods:

Distrigas
Employee Count
Square Footage
# of Transactions
# of Computer Accounts (E-mail)
# of Vehicles
Surveys

Prepared by: Mike Rawlins, Manager Accounting, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.07
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.07 Please provide the calculations for the Questar distrigas allocation of corporate overhead for 2013, 2014 and 2015.

Answer: The Distrigas calculations for 2013, 2014 and 2015 are attached as DPU 2.07 Attachment 1, DPU 2.07 Attachment 2 and DPU 2.07 Attachment 3.

Prepared by: David Alder, Senior Financial Reporting Analyst, Questar Corporation

To: Distribution

From: Greg Sandberg

Date: April 3, 2013

Subject: **Distrigas Percentages for 2013**

Questar Corporation

The Distrigas percentages used in allocating Questar Corporation's general and administrative expenses and other corporate charges for 2013 have been finalized. Consistent with prior years, the allocation percentages were calculated giving equal weight to the elements of the Distrigas calculation that include gross plant, gross revenues less product costs, and gross payroll. The information used to calculate the revenue and plant elements of the Distrigas percentages was taken from 2012 year-end financial statements of Questar Corporation, its consolidated subsidiaries and its unconsolidated affiliate. The gross payroll information was retrieved from the PeopleSoft HR system servicing Questar Corporation and each affiliate company and adjusted based on a forecast of 2013 payroll (see payroll note under the next heading). The following table compares the Distrigas percentages used for allocating Questar Corporation's general and administrative expenses for 2013 and 2012:

Company*	**Allocation Percentages for Corporate G&A Expenses** **2013**	2012	**Increase (Decrease)**
Questar Gas	**45.29%**	45.34%	(0.05%)
Wexpro	**24.58%**	23.52%	1.06%
Questar Pipeline-consolidated (less QIC)	**28.46%**	29.40%	(0.94%)
Questar InfoComm (QIC)	**1.67%**	1.74%	(0.07%)
Total	**100.00%**	100.00%	

*Due to its small size, Questar Fueling has not been included in 2013 calculations.

In addition to the above percentages used in allocating corporate general and administrative expenses, there is a second category of Distrigas percentages (which includes an allocation attributable to Questar Corporation-parent) used to allocate certain corporate charges for consulting and professional services. These same percentages are also used to allocate certain charges related to the corporate shared services group. The following table compares the second category of Distrigas percentages used in allocating Questar Corporation's shared services group and other corporate charges for 2013 and 2012.

Company	**Allocation Percentages for Corporate Shared Services and Other Charges** **2013**	2012	**Inc. (Dec.)**
Questar Gas	**39.89%**	40.43%	(0.54%)
Wexpro	**23.33%**	22.44%	0.89%
Questar Pipeline-consolidated (less QIC)	**26.48%**	27.56%	(1.08%)
Questar InfoComm (QIC)	**1.38%**	1.47%	(0.09%)
Questar Corp	**8.92%**	8.10%	0.82%
Total	**100.00%**	100.00%	

Detail Schedules and Assumptions for the 2013 Calculation

The accompanying Schedules I, II and III provide the details for the 2013 Distrigas calculation. Schedule I excludes Questar Corporation's Distrigas components and provides the percentages for use in allocating Questar Corporation's general and administrative expenses. Schedule II includes Questar Corporation's Distrigas components and provides the percentages for use in allocating corporate shared services and other charges. Schedule III provides the adjustments made to gross plant, gross revenues and gross payroll. Consistent with 2012, on Schedule III are adjustments to capture the effects of Questar Pipeline's 50% interest in unconsolidated affiliate White River Hub, LLC. Schedule IV provides a year-to-year comparison of the Schedule I Distrigas components and allocation percentages for the 2013 and 2012 calculations.

In late 2012 personnel in the Telecomm group were transferred from Questar Gas to Questar Corporation-parent and in early 2013 approximately 100 employees retired in response to an incentive offered by Questar. To reflect these changes, gross payroll information used in the 2013 calculation incorporates a forecast of amounts to be paid to employees in 2013 based on their new company assignments or retirement status, as applicable.

The Telecomm transfer also involved a movement of gross plant from Questar Gas to Questar Pipeline. Because the plant transfers were completed as of year-end 2012, the unaltered December 31, 2012 financial statements reflected the updated plant configuration and were used in the 2013 calculation.

Explanation of Year-to-Year Changes in Distrigas Components and Percentages

Based on the data in Schedule IV that compares the Schedule I Distrigas components of 2013 with 2012, overall gross plant increased $307.6 million or 6.2% and overall gross revenues less product costs increased $32.8 million or 3.7%. The overall estimated gross payroll for 2012 (proportioned among entities based on a 2013 estimate) was $3.4 million or 3.1% higher than the 2011 amount. Questar Gas's overall Distrigas percentage was down slightly (-0.05%), resulting from decreases in its share of gross revenues less product costs (-0.68%) and gross plant (-0.09%), mostly offset by an increase in its share of gross payroll (+0.62%) relative to Wexpro and Questar Pipeline. Wexpro's overall Distrigas percentage increased by 1.06% due to increased shares of gross revenues (+1.58%), gross plant (+1.26%) and gross payroll (+0.36%) relative to Questar Pipeline and Questar Gas. Questar Pipeline's (including Questar InfoComm) overall Distrigas percentage decreased by 1.01% due to decreases in its share of gross plant (-1.17%), gross payroll (-0.98%), and gross revenues less product costs (-0.90%) relative to Wexpro and Questar Gas.

If you have any questions regarding the Distrigas calculation for 2013, please call me at extension 5117.

Distribution:

Michelle Ashton
Craig Brown
Brad Burton
Jeff Callor
Dave Curtis
Kent Dickson
Koby Glazier
Kevin Hadlock
Greg Heiner
Bill Hunt
Craig Kellersberger
Graeme Layton
Connie Marshall
Barrie McKay
Brady Rasmussen
Jeff West
John Wilkey
Julie Wray
John Yin

To: Distribution

From: Craig Kellersberger

Date: April 2, 2014

Subject: **Distrigas Percentages for 2014**

Questar Corporation

The Distrigas percentages used in allocating Questar Corporation's general and administrative expenses and other corporate charges for 2014 have been finalized. Consistent with prior years, the allocation percentages were calculated giving equal weight to the elements of the Distrigas calculation that include gross plant, gross revenues less product costs, and gross payroll. The information used to calculate the plant element of the Distrigas percentages was taken from the 2013 year-end financial statements of Questar Corporation, its consolidated subsidiaries and its unconsolidated affiliate except for Questar Fueling. The data used to calculate the Questar Fueling plant is the average of the December 31, 2013 balance and the 2014 ending budget amount. The gross revenue less product costs information came from the Questar Corporation 2014 budget consolidating income statement and from the Wexpro 2014 budget combined income statement. The gross payroll information was retrieved from the PeopleSoft HR system servicing Questar Corporation and each affiliate company and adjusted based on a forecast of 2014 payroll (see payroll note under the next heading). The following table compares the Distrigas percentages used for allocating Questar Corporation's general and administrative expenses for 2014 and 2013:

Company	**Allocation Percentages for Corporate G&A Expenses** 2014	2013	**Increase (Decrease)**
Questar Gas	**44.99%**	45.29%	(0.30%)
Wexpro	**24.79%**	24.58%	0.21%
Wexpro II	**1.90%**	0.00%	1.90%
Wexpro Development	**0.21%**	0.00%	0.21%
Total Wexpro	**26.90%**	24.58%	2.32%
Questar Pipeline-consolidated (less QIC)	**26.25%**	28.46%	(2.21%)
Questar InfoComm (QIC)	**1.33%**	1.67%	(0.34%)
Total Questar Pipeline-consolidated	**27.58%**	30.13%	(2.55%)
Questar Fueling	**0.53%**	0.00%	0.53%
Total	**100.00%**	100.00%	

In addition to the above percentages used in allocating corporate general and administrative expenses, there is a second category of Distrigas percentages (which includes an allocation attributable to Questar Corporation-parent) used to allocate certain corporate charges for consulting and professional services. These same percentages are also used to allocate certain charges related to the corporate shared services group. The following table compares the second category of Distrigas percentages used in allocating Questar Corporation's shared services group and other corporate charges for 2014 and 2013.

Company	Allocation Percentages for Corporate Shared Services and Other Charges 2014	2013	Inc. (Dec.)
Questar Gas	**39.74%**	39.89%	(0.15%)
Wexpro	**23.65%**	23.33%	0.32%
Wexpro II	**1.82%**	0.00%	1.82%
Wexpro Development	**0.16%**	0.00%	0.16%
Total Wexpro	**25.63%**	23.33%	2.30%
Questar Pipeline-consolidated (less QIC)	**24.29%**	26.48%	(2.19%)
Questar InfoComm (QIC)	**1.11%**	1.38%	(0.27%)
Total Questar Pipeline-Consolidated	**25.40%**	27.86%	(2.46%)
Questar Fueling	**0.46%**	0.00%	0.46%
Questar Corp	**8.77%**	8.92%	(0.15%)
Total	**100.00%**	100.00%	

Detail Schedules and Assumptions for the 2014 Calculation

The accompanying Schedules I, II and III provide additional details for the 2014 Distrigas calculation. Schedule I excludes Questar Corporation's Distrigas components and provides the percentages for use in allocating Questar Corporation's general and administrative expenses. Schedule II includes Questar Corporation's Distrigas components and provides the percentages for use in allocating corporate shared services and other charges. Schedule III provides the adjustments made to gross plant, gross revenues and gross payroll. Additionally consistent with 2013, Schedule III provides adjustments to capture the effects of Questar Pipeline's 50% interest in unconsolidated affiliate White River Hub, LLC. Schedule IV provides a year-to-year comparison of the Schedule I Distrigas components and allocation percentages for the 2014 and 2013 calculations.

Gross Plant Assumptions

Gross plant was transferred from Wexpro Development to Wexpro II on February 1, 2014. The plant was allocated to Wexpro II for the entire year. The 2013 financial statements amounts were used in the 2014 calculation. In the event of a Wexpro Development acquisition in 2014, a Distrigas prospective adjustment may be made if material.

Gross Revenue Assumptions

The Questar Fueling gross revenues less product costs were insignificant in 2013. Wexpro II didn't exist in 2013. As a result, the 2014 budget income statements give a better representation of the revenues less product costs expected in 2014 and were used in the 2014 calculation instead of the 2013 financial statements. In the event of a Wexpro Development acquisition in 2014, a Distrigas prospective adjustment may be made if material.

Gross Payroll Assumptions

In early 2013, approximately 100 employees retired in response to an incentive offered by Questar. On September 1, 2013, Wexpro Development started operations and incurred only a partial year payroll. Subsequently, on February 1, 2014, Wexpro II was formed but had no 2013 payroll. Given these circumstances, the 2013 gross payroll was inadequate for the 2014 calculation. Consequently, the gross payroll data used in the calculation incorporates forecasted payroll paid employees in 2014.

Explanation of Year-to-Year Changes in Distrigas Components and Percentages

Based on the data in Schedule IV comparing the Schedule I Distrigas 2014 components with 2013, overall gross plant increased $353.4 million or 6.7% and overall gross revenues less product costs increased $80.7 million or 8.8%. The overall estimated gross payroll for 2013 (proportioned among entities based on a 2014 estimate) was $3.0 million or 2.6% higher than the 2012 amount.

- Questar Gas's overall Distrigas percentage was down (-0.30%), resulting from decreases in its share of gross revenues less product costs (-0.52%) and gross payroll (-0.86%), partially offset by an increase in its share of gross plant (+0.46%) relative to Wexpro, Questar Pipeline and Questar Fueling.
- Wexpro's combined overall Distrigas percentage increased by 2.32% due to increased shares of gross revenues less product costs (+4.07%), gross plant (+2.40%) and gross payroll (+0.48%) relative to Questar Gas, Questar Pipeline and Questar Fueling.
- Questar Pipeline's (including Questar InfoComm) overall Distrigas percentage decreased by 2.55% due to decreases in its share of gross revenues less product costs (-3.90%), gross plant (-3.36%), and gross payroll (-0.36%) relative to Questar Gas, Wexpro and Questar Fueling.
- Questar Fueling's overall Distrigas percentage increased by 0.53% due to increases in its share of gross payroll (+0.74%), gross plant (+0.50%), and gross revenues less product costs (+0.35%) relative to Questar Gas, Wexpro and Questar Pipeline.

If you have any questions regarding the Distrigas calculation for 2014, please call me at extension 5342.

Distribution:

Michelle Ashton	Kent Dickson	Graeme Layton	Greg Sandberg
Craig Brown	Koby Glazier	Connie Marshall	John Wilkey
Brad Burton	Kevin Hadlock	Barrie McKay	Julie Wray
Jeff Callor	Greg Heiner	Kelly Mendenhall	John Yin
Dave Curtis	Tony Ivins	Brady Rasmussen	

To: Distribution

From: Craig Kellersberger

Date: April 1, 2015

Subject: **Distrigas Percentages for 2015**

Questar Corporation

The Distrigas percentages used in allocating Questar Corporation's general and administrative expenses and other corporate charges for 2015 have been finalized. Consistent with prior years, the allocation percentages were calculated giving equal weight to the elements of the Distrigas calculation that include gross plant, gross revenues less product costs, and gross payroll. The information used to calculate the plant element of the Distrigas percentages was taken from the 2014 year-end financial statements of Questar Corporation, its consolidated subsidiaries and its unconsolidated affiliate. The gross revenue less product costs information came from the Questar Corporation 2014 year-end consolidating income statement and from the Wexpro 2015 budget combined income statement. The gross payroll information was retrieved from the PeopleSoft HR system servicing Questar Corporation and each affiliate company. The following table compares the Distrigas percentages used for allocating Questar Corporation's general and administrative expenses for 2015 and 2014:

Company	Allocation Percentages for Corporate G&A Expenses 2015	2014	Increase (Decrease)
Questar Gas	**44.72%**	44.99%	(0.27%)
Wexpro	**23.87%**	24.79%	(0.92%)
Wexpro II	**1.80%**	1.90%	(0.10%)
Wexpro Development	**1.44%**	0.21%	1.23%
Total Wexpro	**27.11%**	26.90%	0.21%
Questar Pipeline-consolidated (less QIC)	**26.24%**	26.25%	(0.01%)
Questar InfoComm (QIC)	**1.37%**	1.33%	0.04%
Total Questar Pipeline-consolidated	**27.61%**	27.58%	0.03%
Questar Fueling	**0.56%**	0.53%	0.03%
Total	**100.00%**	100.00%	

In addition to the above percentages used in allocating corporate general and administrative expenses, there is a second category of Distrigas percentages (which includes an allocation attributable to Questar Corporation-parent) used to allocate certain corporate charges for consulting and professional services. These same percentages are also used to allocate certain charges related to the corporate shared services group.

The following table compares the second category of Distrigas percentages used in allocating Questar Corporation's shared services group and other corporate charges for 2015 and 2014.

Company	Allocation Percentages for Corporate Shared Services and Other Charges 2015	2014	Inc. (Dec.)
Questar Gas	**39.37%**	39.74%	(0.37%)
Wexpro	**22.72%**	23.65%	(0.93%)
Wexpro II	**1.72%**	1.82%	(0.10%)
Wexpro Development	**1.29%**	0.16%	1.13%
Total Wexpro	**25.73%**	25.63%	0.10%
Questar Pipeline-consolidated (less QIC)	**24.16%**	24.29%	(0.13%)
Questar InfoComm (QIC)	**1.12%**	1.11%	0.01%
Total Questar Pipeline-Consolidated	**25.28%**	25.40%	(0.12%)
Questar Fueling	**0.47%**	0.46%	0.01%
Questar Corp	**9.15%**	8.77%	0.38%
Total	**100.00%**	100.00%	

Detail Schedules and Assumptions for the 2015 Calculation

The accompanying Schedules I, II and III provide additional details for the 2015 Distrigas calculation. Schedule I excludes Questar Corporation's Distrigas components and provides the percentages for use in allocating Questar Corporation's general and administrative expenses. Schedule II includes Questar Corporation's Distrigas components and provides the percentages for use in allocating corporate shared services and other charges. Schedule III provides the adjustments made to gross plant, gross revenues and gross payroll. Additionally, Schedule III provides adjustments to capture the effects of Questar Pipeline's 50% interest in unconsolidated affiliate White River Hub, LLC. Schedule IV provides a year-to-year comparison of the Schedule I Distrigas components and allocation percentages for the 2015 and 2014 calculations.

Gross Plant Assumptions

The 2014 financial statements amounts were used in the 2015 calculation. In the event of a Wexpro Development acquisition in 2015, a Distrigas prospective adjustment may be made if material.

Gross Revenue Assumptions

The 2014 financial statements amounts were used in the 2015 calculation. In the event of a Wexpro Development acquisition in 2015, a Distrigas prospective adjustment may be made if material.

Gross Payroll Assumptions

The 2014 payroll amounts were used in the 2015 calculation. Payroll amounts were allocated to Wexpro II and Wexpro Development using information provided by Payroll personnel. Employees of Wexpro Company provide services to Wexpro II and Wexpro Development. A similar allocation was performed to allocate Questar Corporation and Questar Gas employees' payroll to Questar Fueling, which has no employees of its own. Finally, consistent with prior years, payroll for employees of Questar Project Employee Company (QPEC) has been allocated to the companies to which those individuals provide service.

Explanation of Year-to-Year Changes in Distrigas Components and Percentages

Based on the data in Schedule IV comparing the Schedule I Distrigas 2015 components with 2014, overall gross plant increased $270.9 million or 4.8%, overall gross revenues less product costs increased $13.1 million or 1.3%, and overall gross payroll increased $2.5 million or 2.1%.

- Questar Gas's overall Distrigas percentage was down 0.27%, resulting from decreases in its share of gross revenues less product costs (-0.13%) and gross payroll (-1.42%), partially offset by an increase in its share of gross plant (+0.74%) relative to Wexpro, Questar Pipeline and Questar Fueling.
- Wexpro's combined overall Distrigas percentage increased by 0.21% due to increased shares of gross revenues less product costs (+0.28%) and gross payroll (+0.64%), partially offset by a decrease in its share of gross plant (-0.27%) relative to Questar Gas, Questar Pipeline and Questar Fueling.
- Questar Pipeline's (including Questar InfoComm) overall Distrigas percentage increased by 0.03% due to increases in its share of gross revenues less product costs (+0.03%) and gross payroll (+0.60%), partially offset by a decrease in gross plant (-0.55%) relative to Questar Gas, Wexpro and Questar Fueling.
- Questar Fueling's overall Distrigas percentage increased by 0.03% due to increases in its share of gross payroll (+0.18%) and gross plant (+0.08%), partially offset by a decrease in gross revenues less product costs (-0.18%) relative to Questar Gas, Wexpro and Questar Pipeline.

If you have any questions regarding the Distrigas calculation for 2015, please call me at extension 5342.

Distribution:

Michelle Ashton	Kent Dickson	Connie Marshall	John Wilkey
Craig Brown	Koby Glazier	Barrie McKay	Julie Wray
Brad Burton	Kevin Hadlock	Kelly Mendenhall	John Yin
Jeff Callor	Greg Heiner	Brent Ray	
Dave Curtis	Tony Ivins	Greg Sandberg	

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.08
Requested by Division of Public Utilities
Date of QGC Response April 4, 2016

DPU 2.08 Please identify any other costs that are allocated to the operating entities through the distrigas or similar allocation method.

Answer: In addition to the corporate costs identified in DPU 2.05, DPU 2.06 and DPU 2.07, the other costs allocated to operating entities include telecommunication charges from Questar Pipeline Company. DPU 2.08 Attachment 1.xlsx, show these cost allocations and amounts for 2013, 2014 and 2015, respectively.

Prepared by: Steve Gomez, Team Leader Accounting, Questar Pipeline Company

QPC Telecom Allocations to Affiliates

December 2015 Allocation factors

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
	Product	Allocation Method	QGC	Wexpro	Questar Corp	Questar Pipeline	Overthrust Pipeline	Questar Energy Services	Southern Trails	White River Hub	Questar Fueling	Total
1	Network	Number of Current Ports	43.92%	6.97%	14.74%	32.18%	0.25%	0.43%	0.25%	0.27%	1.01%	100.00%
2	Long Distance	Number of Minutes	94.83%	0.27%	2.45%	2.42%		0.01%	0.00%	0.00%	0.02%	100.00%
3	Low Band Radio	Number of Radios	2.25%	29.96%	14.61%	52.81%		0.37%				100.00%
4	Telemetry	Number of RTU's	33.21%			56.55%	5.50%		2.47%	1.33%	0.95%	100.00%
5	Small Mobile Radio	Number of Radios	73.03%	0.33%	16.09%	10.54%						100.00%
6	Tech Support	Labor hours	78.27%	3.52%	10.57%	7.64%						100.00%
7	InMotion	Number of Radios	80.58%		9.47%	8.19%			1.77%			100.00%

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.01
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.01 Please identify the amount of Corporate overhead that has been paid by each Questar operating entity as of December 31, 2010, 2011 and 2012. The response should be in similar format to the response for DPU DR 2.5.

Answer: Please see attachments DPU 5.01 Attachment 1, Attachment 2 and Attachment 3 for the corporate overhead of 2010, 2011 and 2012.

Prepared by: Mike Rawlins, Accounting Manager, Questar Gas Company

2010 Corporate Charges to Subsidiaries

DIRECT CHARGES

Line	(A) Transactions	(B)	(C) QEP	(D) QPC	(E) WEX	(F) QGC	(G) Total Direct Charges
1	284	Misc Other Income	-	-	-	-	-
2	400	Labor	148,340.05	324,565.18	62,008.98	863,803.08	1,398,717.29
3	410	Travel	159.00	-	229.05	221.31	609.36
4	411	Air Travel	36.00	2,531.40	299.35	4,021.00	6,887.75
5	412	Sundries	16,777.53	3,562.16	5,331.43	2,321.40	27,992.52
6	413	Training	57,005.42	6,600.00	549.26	9,900.00	74,054.68
7	414	Meals-Travel/Entertain	167.00	177.43	259.94	-	604.37
8	416	Meals-OnPremise, OT	-	34.47	-	-	34.47
9	453	Computer Software	389,587.27	-	55,389.99	457,507.68	902,484.94
10	461	Supplies and Equipment	(18,457.54)	4,731.81	780.30	(166,239.84)	(179,185.27)
11	482	Communication Charges	-	-	-	-	-
12	496	Outside Counsel	8,346.00	-	-	41,922.35	50,268.35
13	505	Consultants	261,272.99	432,547.58	144,188.00	520,814.62	1,358,823.19
14	530	Contract Library Research	-	1,100.00	-	-	1,100.00
15	535	Public Communications	-	-	-	-	-
16	542	Debt Service	-	8,250.00	-	13,000.00	21,250.00
17	546	Consultants/Contracted Svcs	44,598.22	17,287.89	3,571.74	37,868.21	103,326.06
18	547	Investor Relations	10,622.00	-	-	-	10,622.00
19	560	Assoc Company Labor	-	-	-	-	-
20	561	Assoc Company Labor Ovhd	-	-	-	-	-
21	562	Assoc Company Vehicle Clrg	-	-	-	-	-
22	564	Assoc Company Office Suppl	-	-	-	-	-
23	565	Assoc Company Other	14,658.19	-	-	36,645.46	51,303.65
24	566	Assoc Company Printing	-	-	-	-	-
25	567	Assoc Company Mail-Stationary	-	-	-	-	-
26	596	Building Rents	-	-	-	-	-
27	610	Rent	-	7,575.00	3,030.00	34,970.00	45,575.00
28	619	Contributions Non-charitable	-	-	-	3,750.00	3,750.00
29	620	Contributions and Donations	-	1,136.91	1,136.91	1,136.91	3,410.73
30	621	Director Fees & Meetings	-	-	-	-	-
31	622	Director Expenses	-	-	-	-	-
32	626	Group Entertainment	-	-	-	-	-
33	628	Dues & Memberships	-	-	10,000.00	-	10,000.00
34	629	Postage & Express	-	-	-	25.00	25.00
35	631	Publications & Subscriptions	-	-	-	-	-
36	635	Licenses, Permits and Fees	135,785.00	-	-	-	135,785.00
37	642	Insurance & Bonding	2,495,604.98	2,301,378.58	782,947.87	2,751,491.92	8,331,423.35
38	644	Bad Debts	-	-	-	-	-
39	645	Third Party Claims	659.00	2,008.63	71.00	41,452.33	44,190.96
40	650	Long-term Disability	33,773.40	18,724.41	-	21,768.00	74,265.81
41	652	Employee Benefits-WC&GPL	27,957.85	14,397.12	683.41	384,768.32	427,806.70
42	653	Employee Benefits-Medical	3,092,270.39	2,434,810.56	855,574.82	9,761,513.77	16,144,169.54
43	654	Employee Benefits-Life Insur	54,570.13	20,557.12	5,771.26	79,548.11	160,446.62
44	655	Employee Benefits-Retirement	1,313,320.22	3,911,825.17	1,133,548.42	14,329,494.04	20,688,187.85
45	656	Employee Benefits-Empl Invest Plan	-	-	-	-	-
46	657	Employee Benefits-Miscellaneous	67,473.62	54,001.11	13,919.36	267,795.82	403,189.91
47	658	Emp Ben-Post Ret Ben OT Pens	244,613.75	(59,706.31)	170,701.33	1,643,261.11	1,998,869.88
48	659	Deferred Comp - (Non-Qualified)	-	-	-	-	-
49	666	Depreciation	-	-	-	-	-
50	673	Bank Service Charge	131,268.36	195,665.65	10,536.23	941,288.38	1,278,758.62
51	677	Interest Expense - Assoc Company	216,042.74	110.25	49,870.55	393,082.86	659,106.40
52	679	Interest Expense - Misc	-	(9,622.50)	-	(7,803.75)	(17,426.25)
53	687	Amortization of Debt Expense	-	-	-	-	-
54	710	Federal Income Tax	15,294,000.00	19,098,000.00	31,011,000.00	(7,310,000.00)	58,093,000.00
55	715	State Income Tax	1,067,000.00	86,396.00	232,468.00	(2,420,518.00)	(1,034,654.00)
56	749	Property Tax	-	-	-	-	-
57	850	Garage Vehicles & Equip	-	-	-	15.01	15.01
58	902	Information Technology	-	-	-	-	-
59	920	Labor Overhead	99,983.15	282,113.86	57,894.40	933,104.55	1,373,095.96
60	927	Vehicle Clearing	-	-	-	-	-
61	984	Company Services-Other	29,623.82	135,521.04	50,410.05	644,621.66	860,176.57
62	985	Transfer to Affiliates	415,715.99	1,326,897.21	215,601.33	3,126,352.49	5,084,567.02
63		Total Charges to Subsidiaries	25,652,774.53	30,623,177.73	34,877,772.98	27,442,903.80	118,596,629.04

ALLOCATED CHARGES

Line	(A) Transactions	(B)	(H) QEP	(I) QPC	(J) WEX	(K) QGC	(L) Total Allocated	(M) Total Direct & Allocated
1	284	Misc Other Income	(28)	(21)	(15)	(36)	(100.00)	(100.00)
2	400	Labor	6,033,231	3,102,736	2,167,779	5,777,701	17,081,448.18	18,480,165.47
3	410	Travel	1,059	2,878	1,988	5,539	11,464.14	12,073.50
4	411	Air Travel	16,834	8,576	6,093	15,541	47,045.23	53,932.98
5	412	Sundries	10,710	14,297	10,248	24,663	59,917.21	87,909.73
6	413	Training	25,548	15,145	10,168	31,290	82,150.97	156,205.65
7	414	Meals-Travel/Entertain	8,843	6,631	4,737	11,703	31,913.22	32,517.59
8	416	Meals-OnPremise, OT	8,416	3,189	1,883	8,264	21,751.80	21,786.27
9	453	Computer Software	65,659	63,432	45,829	107,515	282,435.09	1,184,920.03
10	461	Supplies and Equipment	14,291	18,289	12,884	33,300	78,763.70	(100,421.57)
11	482	Communication Charges	20,111	17,779	12,841	30,210	80,941.53	80,941.53
12	496	Outside Counsel	93,011	69,212	49,959	118,259	330,441.71	380,710.06
13	505	Consultants	31,756	132,554	87,933	268,484	520,727.02	1,879,550.21
14	530	Contract Library Research	23,857	15,521	11,197	26,653	77,229.07	78,329.07
15	535	Public Communications	18,168	3,948	2,822	7,315	32,252.80	32,252.80
16	542	Debt Service	-	-	-	-	-	21,250.00
17	546	Consultants/Contracted Svcs	41,679	18,807	11,837	42,830	115,153.39	218,479.45
18	547	Investor Relations	176,057	110,401	79,631	189,862	555,952.13	566,574.13
19	560	Assoc Company Labor	72,176	67,018	48,414	113,718	301,325.66	301,325.66
20	561	Assoc Company Labor Ovhd	53,973	53,279	38,496	90,254	236,003.25	236,003.25
21	562	Assoc Company Vehicle Clrg	1,181	1,327	840	3,220	6,569.12	6,569.12
22	564	Assoc Company Office Suppl	2,375	4,478	3,019	8,732	18,604.12	18,604.12
23	565	Assoc Company Other	53,413	54,488	39,373	92,223	239,497.65	290,801.30
24	566	Assoc Company Printing	10,050	5,732	3,343	15,660	34,786.04	34,786.04
25	567	Assoc Company Mail-Stationary	6,733	5,380	3,216	13,401	28,730.52	28,730.52
26	596	Building Rents	348,245	256,634	185,238	438,643	1,228,759.56	1,228,759.56
27	610	Rent	1,886	1,992	1,440	3,369	8,686.50	54,261.50
28	619	Contributions Non-charitable	10,591	10,375	7,496	17,578	46,039.17	49,789.17
29	620	Contributions and Donations	198,898	264,474	191,157	445,529	1,100,058.00	1,103,468.73
30	621	Director Fees & Meetings	1,287,892	1,016,394	733,827	1,733,196	4,771,307.60	4,771,307.60
31	622	Director Expenses	22,339	8,294	5,963	14,668	51,263.65	51,263.65
32	626	Group Entertainment	4,098	4,488	3,244	7,582	19,411.99	19,411.99
33	628	Dues & Memberships	53,501	41,376	29,487	72,662	197,027.04	207,027.04
34	629	Postage & Express	5,554	6,076	4,392	10,267	26,289.14	26,314.14
35	631	Publications & Subscriptions	35,449	13,518	9,665	24,319	82,951.65	82,951.65
36	635	Licenses, Permits and Fees	53,384	14,037	9,901	26,160	103,481.86	239,266.86
37	642	Insurance & Bonding	13,954	8,377	6,041	14,433	42,804.91	8,374,228.26
38	644	Bad Debts	-	(0)	(0)	(0)	(0.03)	(0.03)
39	645	Third Party Claims	-	-	-	-	-	44,190.96
40	650	Long-term Disability	-	-	-	-	-	74,265.81
41	652	Employee Benefits-WC&GPL	-	-	-	-	-	427,806.70
42	653	Employee Benefits-Medical	5	64	30	251	350.57	16,144,520.11
43	654	Employee Benefits-Life Insur	-	-	-	-	-	160,446.62
44	655	Employee Benefits-Retirement	-	44,129	21,194	172,452	237,775.23	20,925,963.08
45	656	Employee Benefits-Empl Invest Plan	16,706	7,002	1,650	27,501	52,858.84	52,858.84
46	657	Employee Benefits-Miscellaneous	-	-	-	-	-	403,189.91
47	658	Emp Ben-Post Ret Ben OT Pens	-	-	-	-	-	1,998,869.88
48	659	Deferred Comp - (Non-Qualified)	194,236	122,684	88,494	210,922	616,335.51	616,335.51
49	666	Depreciation	80,227	59,858	43,208	102,267	285,560.31	285,560.31
50	673	Bank Service Charge	211,930	212,854	153,802	360,408	938,994.89	2,217,753.51
51	677	Interest Expense - Assoc Company	-	-	-	-	-	659,106.40
52	679	Interest Expense - Misc	11	2	2	4	19.39	(17,406.86)
53	687	Amortization of Debt Expense	72,130	101,209	73,192	170,101	416,631.96	416,631.96
54	710	Federal Income Tax	-	-	-	-	-	58,093,000.00
55	715	State Income Tax	-	-	-	-	-	(1,034,654.00)
56	749	Property Tax	5,662	1,230	880	2,280	10,052.17	10,052.17
57	850	Garage Vehicles & Equip	-	16	11	26	53.40	68.41
58	902	Information Technology	114,351	87,957	63,498	150,116	415,922.17	415,922.17
59	920	Labor Overhead	1,111,421	796,898	521,811	1,698,782	4,128,912.63	5,502,008.59
60	927	Vehicle Clearing	31,307	6,803	4,863	12,605	55,578.00	55,578.00
61	984	Company Services-Other	-	-	-	-	-	860,176.57
62	985	Transfer to Affiliates	-	-	-	-	-	5,084,567.02
63		Total Charges to Subsidiaries	10,662,880.75	6,881,819.29	4,815,002.09	12,752,427.53	35,112,129.66	153,708,758.70

2011 Corporate Charges to Subsidiaries

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			DIRECT CHARGES				ALLOCATED				
Line	Transactions		QPC	WEX	QGC	Total Direct Charges	QPC	WEX	QGC	Total Allocated	Total Direct & Allocated
1	284	Misc Other Income	-	-	(1,548.78)	(1,548.78)	(41,572.72)	(29,844.50)	(60,898.82)	(132,316.04)	(133,864.82)
2	289	Revenue - Printing, Mail, Statny	-	-	-	-	(9,645.70)	(1,396.61)	(83,847.24)	(94,889.55)	(94,889.55)
3	400	Labor	1,436,373.77	286,235.61	7,151,719.54	8,874,328.92	4,141,179.65	1,769,384.23	9,512,431.45	15,422,995.33	24,297,324.25
4	402	Incentive Wages	-	-	-	-	2,171,269.62	1,574,289.33	3,046,025.73	6,791,584.68	6,791,584.68
5	403	Share-based Compensation	-	-	-	-	1,685,658.61	1,222,194.76	2,364,772.87	5,272,626.24	5,272,626.24
6	410	Travel	17,242.67	2,618.39	17,077.90	36,938.96	55,675.13	32,144.09	102,757.68	190,576.89	227,515.85
7	411	Air Travel	446.00	866.80	997.40	2,310.20	1,132.34	800.74	1,657.87	3,590.95	5,901.15
8	412	Sundries	1,413.42	-	2,708.42	4,121.84	3,493.35	2,043.21	6,451.37	11,987.93	16,109.77
9	413	Training	11,174.63	39.95	6,987.00	18,201.58	35,091.49	17,785.87	72,034.68	124,912.04	143,113.62
10	414	Meals-Travel/Entertain	6,323.21	653.85	7,686.07	14,663.13	34,401.78	20,946.41	57,618.94	112,967.13	127,630.26
11	416	Meals-OnPremise, OT	99.38	-	1,381.64	1,481.02	7,144.36	3,087.64	17,095.76	27,327.77	28,808.79
12	453	Computer Software	286,445.58	69,937.06	853,772.95	1,210,155.59	273,477.05	136,883.85	823,115.57	1,233,476.47	2,443,632.06
13	459	Computer Hardware	18,881.48	-	279,225.47	298,106.95	27,119.33	13,390.01	87,941.18	128,450.52	426,557.47
14	460	Warehouse Supplies	6,277.99	-	62,575.61	68,853.60	347.78	80.99	784.04	1,212.81	70,066.41
15	461	Supplies and Equipment	941,482.53	31,882.50	(2,542,710.74)	(1,569,345.71)	165,422.52	70,059.59	632,710.58	868,192.70	(701,153.01)
16	466	Intercompany Rent	-	-	-	-	183.72	133.20	257.73	574.65	574.65
17	482	Communication Charges	-	-	28,950.00	28,950.00	252,706.69	183,225.83	354,518.64	790,451.16	819,401.16
18	496	Outside Counsel	-	-	-	-	21,935.20	16,352.87	31,409.48	69,697.55	69,697.55
19	505	Consultants	96,803.91	50,840.00	77,935.00	225,578.91	23,416.57	10,923.69	63,845.31	98,185.57	323,764.48
20	530	Contract Library Research	-	-	-	-	4,307.97	3,206.38	5,760.33	13,274.68	13,274.68
21	531	Advertising	888.00	-	10,684.80	11,572.80	98.16	71.34	137.13	306.63	11,879.43
22	535	Public Communications	-	-	-	-	5,212.61	3,781.38	7,318.26	16,312.25	16,312.25
23	542	Debt Service	-	-	-	-	1,118.95	811.30	1,569.75	3,500.00	3,500.00
24	546	Consultants/Contracted Svcs	688,969.68	223,555.23	1,020,613.02	1,933,137.93	464,956.18	310,526.17	842,452.59	1,617,934.94	3,551,072.87
25	547	Investor Relations	-	-	-	-	216,419.23	156,915.79	303,609.71	676,944.72	676,944.72
26	560	Assoc Company Labor	-	-	-	-	75,439.03	55,362.68	142,995.16	273,796.87	273,796.87
27	561	Assoc Company Labor Ovhd	-	-	-	-	28,824.35	21,678.54	47,817.76	98,320.65	98,320.65
28	562	Assoc Company Vehicle Clrg	-	-	-	-	16,823.92	4,205.58	36,555.99	57,585.49	57,585.49
29	565	Assoc Company Other	-	-	-	-	121,707.77	90,592.56	163,265.41	375,565.74	375,565.74
30	568	Assoc Company G&A	-	-	-	-	1,036,196.09	712,550.90	1,652,015.05	3,400,762.03	3,400,762.03
31	596	Building Rents	-	-	-	-	134,222.86	98,795.05	176,753.27	409,771.18	409,771.18
32	610	Rent	10,865.00	4,980.00	10,365.00	26,210.00	486,383.85	334,068.08	825,418.50	1,645,870.43	1,672,080.43
33	619	Contributions Non-charitable	-	-	3,750.00	3,750.00	28,562.00	20,709.01	40,068.99	89,340.00	93,090.00
34	620	Contributions and Donations	-	-	-	-	306,916.80	222,363.89	431,331.19	960,611.88	960,611.88
35	621	Director Fees & Meetings	-	-	-	-	1,109,848.02	804,701.09	1,556,979.17	3,471,528.28	3,471,528.28
36	622	Director Expenses	-	-	-	-	9,363.67	6,789.90	13,133.59	29,287.16	29,287.16
37	626	Group Entertainment	-	-	-	-	3,507.32	2,543.00	4,920.34	10,970.66	10,970.66
38	628	Dues & Memberships	40,197.20	6,052.05	32,788.18	79,037.43	81,539.16	57,736.65	117,717.86	256,993.67	336,031.10
39	629	Postage & Express	-	2,247.06	233,017.80	235,264.86	11,374.19	4,402.59	63,315.24	79,092.02	314,356.88
40	631	Publications & Subscriptions	-	-	-	-	3,698.16	2,715.60	5,450.59	11,864.35	11,864.35
41	635	Licenses, Permits and Fees	400.00	40,014.50	10,407.02	50,821.52	33,119.16	23,864.24	46,677.53	103,660.93	154,482.45
42	641	Regulatory Fees/Expense	-	-	-	-	457.78	323.68	684.42	1,465.88	1,465.88
43	642	Insurance & Bonding	2,309,322.20	734,746.10	2,207,225.15	5,251,293.45	14,737.59	10,685.56	20,675.04	46,098.19	5,297,391.64
44	643	Special Transactions	-	-	-	-	49,509.47	35,926.96	69,352.75	154,789.18	154,789.18
45	644	Bad Debts	-	-	-	-	(0.13)	(0.10)	(0.18)	(0.41)	(0.41)
46	645	Third Party Claims	9,190.07	-	120,469.13	129,659.20	(5.42)	(4.03)	(7.24)	(16.69)	129,642.51
47	650	Long-term Disability	12,351.00	-	9,711.55	22,062.55	-	-	-	-	22,062.55
48	651	Recognition Outstanding Service Empl	-	-	900.00	900.00	1,074.96	584.64	1,914.29	3,573.89	4,473.89
49	652	Employee Benefits-WC&GPL	29,635.50	7,276.31	358,681.32	395,593.13	-	-	-	-	395,593.13
50	653	Employee Benefits-Medical	2,783,643.91	1,332,485.01	8,654,680.85	12,770,809.77	601.83	257.93	1,757.74	2,617.50	12,773,427.27
51	654	Employee Benefits-Life Insur	37,048.84	17,751.20	100,300.89	155,100.93	-	-	-	-	155,100.93
52	655	Employee Benefits-Retirement	8,315,333.80	3,246,410.15	26,015,565.39	37,577,309.34	(193,363.00)	(82,869.86)	(564,742.74)	(840,975.60)	36,736,333.74
53	656	Employee Benefits-Empl Invest Plan	-	-	-	-	3,090.22	1,324.38	9,025.40	13,440.00	13,440.00
54	657	Employee Benefits-Miscellaneous	81,676.64	12,176.35	242,946.10	336,799.09	-	-	-	-	336,799.09
55	658	Emp Ben-Post Ret Ben OT Pens	23,599.12	255,625.34	1,733,305.94	2,012,530.40	-	-	-	-	2,012,530.40
56	659	Deferred Comp - (Non-Qualified)	-	-	-	-	25,582.11	18,548.43	35,888.57	80,019.10	80,019.10
57	666	Depreciation	-	-	-	-	100,483.35	72,848.36	141,004.57	314,336.28	314,336.28
58	673	Bank Service Charge	84,310.85	30,148.60	574,902.29	689,361.74	231,868.23	168,117.45	325,282.32	725,268.00	1,414,629.74
59	677	Interest Expense - Assoc Company	166,318.44	4,481.43	309,710.72	480,510.59	-	-	-	-	480,510.59
60	687	Amortization of Debt Expense	-	-	-	-	207,102.99	150,161.00	290,540.16	647,804.15	647,804.15
61	710	Federal Income Tax	1,567,282.00	(5,974,437.00)	(3,865,534.00)	(8,272,689.00)	-	-	-	-	(8,272,689.00)
62	715	State Income Tax	1,368,653.00	838,319.00	557,146.00	2,764,118.00	-	-	-	-	2,764,118.00
63	749	Property Tax	-	-	-	-	2,805.12	2,033.87	3,935.25	8,774.24	8,774.24
64	850	Garage Vehicles & Equip	2,130.59	97,262.29	105,599.03	204,991.91	19,238.95	3,270.50	42,880.21	65,389.66	270,381.57
65	852	Outside Labor	-	-	5,519.27	5,519.27	-	-	-	-	5,519.27
66	902	Information Technology	-	-	-	-	45,319.06	5,784.25	100,844.38	151,947.69	151,947.69
67	920	Labor Overhead	1,158,272.75	221,684.61	3,459,658.31	4,839,615.67	3,377,331.52	1,439,928.94	7,764,272.93	12,581,533.39	17,421,149.06
68	927	Vehicle Clearing	25,267.27	656.46	48,620.69	74,544.42	4,934.34	1,079.24	18,003.14	24,016.72	98,561.14
69	984	Company Services-Other	147,866.95	74,145.17	535,765.46	757,777.58	-	-	-	-	757,777.58
70	985	Transfer to Affiliates	461,068.39	125,545.82	1,199,664.01	1,786,278.22	-	-	-	-	1,786,278.22
71	989	Clearing Credits	-	-	(102,098.27)	(102,098.27)	-	-	-	-	(102,098.27)
72	Total Charges to Subsidiaries		22,147,255.77	1,744,199.84	49,541,123.13	73,432,578.74	16,918,845.19	9,808,878.11	31,777,257.23	58,504,980.53	131,937,559.27

2012 Corporate Charges to Subsidiaries

Line	(A) Transactions	(B)	(C) DIRECT CHARGES QFC	(D) DIRECT CHARGES QPC	(E) DIRECT CHARGES WEX	(F) DIRECT CHARGES QGC	(G) Total Direct Charges	(H) ALLOCATED CHARGES QPC	(I) ALLOCATED CHARGES WEX	(J) ALLOCATED CHARGES QGC	(K) Total Allocated	(L) Total Direct & Allocated
1	1/	Direct Payments to Expense	1,305.39	6,029,206.02	-	11,203,363.12	17,233,874.53	-	-	-	-	17,233,874.53
2	284	Misc Other Income	-	-	-	-	-	(1,356.81)	(568.93)	(5,685.57)	(7,611.31)	(7,611.31)
3	289	Revenue - Printing, Mail, Statny	-	-	-	-	-	(141.64)	(29.05)	(1,032.31)	(1,203.00)	(1,203.00)
4	400	Labor	12,074.99	1,546,742.18	461,127.45	3,792,072.21	5,812,016.83	4,325,975.03	2,009,890.57	9,957,503.90	16,293,369.50	22,105,386.33
5	402	Incentive Wages	-	5,348.03	-	7,045.38	12,393.41	1,479,150.00	1,117,200.00	2,153,650.00	4,750,000.00	4,762,393.41
6	403	Share-based Compensation	-	-	-	-	-	1,402,122.91	1,059,021.55	2,041,498.17	4,502,642.63	4,502,642.63
7	410	Travel	1,093.17	9,161.96	1,415.12	11,574.10	23,244.35	77,260.75	46,851.26	147,745.34	271,857.34	295,101.69
8	413	Training	-	-	82.92	2,580.98	2,663.90	43,689.74	21,715.09	99,109.81	164,514.64	167,178.54
9	414	Meals-Travel/Entertain	449.42	2,870.12	425.10	7,084.83	10,829.47	48,174.60	30,207.42	85,280.59	163,662.61	174,492.08
10	416	Meals-OnPremise, OT	-	196.34	-	486.40	682.74	7,511.19	4,156.75	16,329.91	27,997.85	28,680.59
11	453	Computer Software	-	-	89,654.08	-	89,654.08	250,507.56	124,779.31	696,703.44	1,071,990.31	1,161,644.39
12	459	Computer Hardware	-	-	-	-	-	21,773.13	14,176.41	50,421.58	86,371.12	86,371.12
13	460	Warehouse Supplies	-	2,588.60	-	52,716.27	55,304.87	968.44	93.77	1,683.99	2,746.21	58,051.08
14	461	Supplies and Equipment	51.35	837,667.15	46,077.58	(3,175,262.39)	(2,291,466.31)	174,396.65	87,166.32	554,481.00	816,043.97	(1,475,422.34)
15	482	Communication Charges	-	-	-	-	-	258,713.97	195,406.31	376,688.87	830,809.15	830,809.15
16	531	Advertising	-	-	-	-	-	2,371.93	1,791.52	3,453.55	7,617.00	7,617.00
17	546	Consultants/Contracted Svcs	-	1,226,283.78	1,413,822.87	929,156.74	3,569,263.39	539,054.47	316,014.71	1,139,051.09	1,994,120.27	5,563,383.66
18	547	Investor Relations	-	-	-	-	-	204,070.08	154,138.96	297,119.44	655,328.48	655,328.48
19	560	Assoc Company Labor	-	-	-	-	-	72,730.50	56,565.40	139,452.46	268,748.36	268,748.36
20	561	Assoc Company Labor Ovhd	-	-	-	-	-	26,795.21	20,214.84	49,967.48	96,977.53	96,977.53
21	562	Assoc Company Vehicle Clrg	-	-	-	-	-	6,657.58	4,004.33	12,332.23	22,994.14	22,994.14
22	565	Assoc Company Other	-	-	-	-	-	160,033.04	124,395.53	224,005.00	508,433.57	508,433.57
23	568	Assoc Company G&A	-	-	-	-	-	1,317,207.84	944,177.60	2,113,865.15	4,375,250.59	4,375,250.59
24	610	Rent	-	167,505.49	110,929.39	117,929.54	396,364.42	1,974,402.42	1,353,749.89	2,282,647.20	5,610,799.51	6,007,163.93
25	611	Questar Center Parking	-	21,340.00	9,450.00	11,300.00	42,090.00	38,820.32	28,681.26	58,621.24	126,122.81	168,212.81
26	620	Contributions and Donations	-	-	-	-	-	902.06	492.72	2,065.60	3,460.38	3,460.38
27	621	Director Fees & Meetings	-	-	-	-	-	593,926.44	448,591.84	864,759.95	1,907,278.24	1,907,278.24
28	622	Director Expenses	-	-	-	-	-	9,949.69	7,514.99	14,486.80	31,951.47	31,951.47
29	624	Mark to Market	-	-	-	-	-	(13,227.17)	(24,814.57)	38,041.74	-	-
30	628	Dues, Publications, Subscriptions	-	-	-	-	-	72,155.46	53,330.54	108,140.64	233,626.64	233,626.64
31	629	Postage & Express	-	77.91	-	182,264.40	182,342.31	8,740.38	4,590.80	33,978.51	47,309.69	229,652.00
32	635	Licenses, Permits and Fees	-	-	7,148.93	550.00	7,698.93	30,017.77	21,997.07	46,967.75	98,982.59	106,681.52
33	641	Regulatory Fees/Expense	-	-	-	-	-	96.27	75.48	136.00	307.75	307.75
34	642	Insurance & Bonding	-	(73,205.83)	821,556.13	(46,900.95)	701,449.35	7,364.11	5,562.11	10,722.19	23,648.41	725,097.76
35	644	Bad Debts	-	-	-	-	-	6,053.07	4,571.88	8,813.30	19,438.25	19,438.25
36	645	Third Party Claims	-	-	3,093.82	-	3,093.82	8,446.76	6,622.83	11,932.32	27,001.91	30,095.73
37	650	Long-term Disability	-	7,500.00	-	21,714.39	29,214.39	-	-	-	-	29,214.39
38	651	Recognition Outstanding Service E	-	-	-	-	-	822.70	463.16	1,421.25	2,707.11	2,707.11
39	652	Employee Benefits-WC&GPL	-	-	2,317.00	-	2,317.00	-	-	-	-	2,317.00
40	653	Employee Benefits-Medical	-	-	1,296,736.48	-	1,296,736.48	137.68	56.89	382.53	577.10	1,297,313.58
41	654	Employee Benefits-Life Insur	-	-	10,188.90	-	10,188.90	-	-	-	-	10,188.90
42	655	Employee Benefits-Retirement	-	43,813.28	7,474,482.06	116,243.50	7,634,538.84	(73,082.49)	(30,195.76)	(203,055.53)	(306,333.78)	7,328,205.06
43	656	Employee Benefits-Empl Invest Pl	-	-	-	-	-	4,300.97	1,777.05	11,949.99	18,028.00	18,028.00
44	657	Employee Benefits-Miscellaneous	-	-	19,655.46	-	19,655.46	-	-	-	-	19,655.46
45	659	Deferred Comp - (Non-Qualified)	-	-	-	-	-	(16.12)	(12.18)	(23.48)	(51.78)	(51.78)
46	666	Depreciation	-	-	-	-	-	205,781.89	155,428.14	299,617.43	660,827.47	660,827.47
47	673	Bank Service Charge	-	-	16,219.93	-	16,219.93	77,971.09	58,891.46	113,526.31	250,388.86	266,608.79
48	677	Interest Expense - Assoc Company	-	-	6,855.26	-	6,855.26	-	-	-	-	6,855.26
49	687	Amortization of Debt Expense	-	-	-	-	-	160,347.88	121,110.54	233,467.34	514,925.76	514,925.76
50	710	Federal Income Tax	-	(4,052,239.00)	54,674,622.00	(19,968,142.00)	30,654,241.00	-	-	-	-	30,654,241.00
51	715	State Income Tax	-	288,501.00	586,560.00	(398,671.00)	476,390.00	-	-	-	-	476,390.00
52	749	Property Tax	-	-	-	-	-	4,095.01	3,092.96	5,962.36	13,150.32	13,150.32
53	850	Garage Vehicles & Equip	-	2,575.01	65.36	98,484.50	101,124.87	21,139.92	4,821.92	49,467.54	75,429.38	176,554.25
54	902	Information Technology	-	-	-	-	-	23,059.09	(28.43)	51,494.62	74,525.28	74,525.28
55	920	Labor Overhead	12,989.77	1,463,527.28	444,667.65	3,569,908.43	5,491,093.13	4,053,188.45	1,882,505.68	9,395,405.00	15,331,099.12	20,822,192.25
56	927	Vehicle Clearing	34.66	219,405.14	10,287.09	604,645.46	834,372.35	45,229.07	11,643.09	123,529.15	180,401.32	1,014,773.67
57	984	Company Services-Other	-	-	87,569.14	-	87,569.14	107,963.24	81,544.49	157,195.04	346,702.77	434,271.91
58	985	Transfer to Affiliates	-	140,202.57	42,293.64	375,617.40	558,113.61	-	-	-	-	558,113.61
58	989	Clearing Credits	-	-	-	(1,035,768.90)	(1,035,768.90)	-	-	-	-	(1,035,768.90)
59	Total Charges to Subsidiaries		27,998.75	7,889,067.03	67,637,303.36	(3,520,007.59)	72,034,361.55	17,786,252.15	10,533,435.49	33,875,277.89	62,194,965.54	134,229,327.09
	2/	Direct Payments to Bal Sheet	-	16,423,229.85	0	47,036,831.05	63,460,060.90					

1/ Amounts that are paid by corporate departments but are recorded directly on the subsidiaries books as expense rather than allocated, such as outside auditor fees, legal fees, and bank fees .

2/ Direct payments to balance sheet accounts, such as labor overhead items, pension contributions, and insurance premiums that later are charged to expense or capital accounts through other allocations or amortizations.

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.01U
Requested by Division of Public Utilities
Date of QGC Response June 1, 2016

DPU 5.01U Please identify the amount of Corporate overhead that has been paid by each Questar operating entity as of December 31, 2010, 2011 and 2012. The response should be in similar format to the response for DPU DR 2.5.

Answer: DPU 5.01U Attachment 3.xlsx, has been updated to correct amounts on line 1 – Direct Payments to Expense, and the Direct Payments to the Balance Sheet at the bottom of the sheet. About $14 million was determined to be balance sheet rather than direct expense. The total on line 59 also changed to reflect this correction. No other lines have been changed.

Prepared by: Mike Rawlins, Accounting Manager, Questar Gas Company

2012 Corporate Charges to Subsidiaries

Line	(A) Transactions	(B)	DIRECT CHARGES (C) QFC	(D) QPC	(E) WEX	(F) QGC	(G) Total Direct Charges	ALLOCATED CHARGES (H) QPC	(I) WEX	(J) QGC	(K) Total Allocated	(L) Total Direct & Allocated
1	1/	Direct Payments to Expense	1,557.39	470,919.33	-	2,743,333.98	3,215,810.70	-	-	-	-	3,215,810.70
2	284	Misc Other Income	-	-	-	-	-	(1,356.81)	(568.93)	(5,685.57)	(7,611.31)	(7,611.31)
3	289	Revenue - Printing, Mail, Statny	-	-	-	-	-	(141.64)	(29.05)	(1,032.31)	(1,203.00)	(1,203.00)
4	400	Labor	12,074.99	1,546,742.18	461,127.45	3,792,072.21	5,812,016.83	4,325,975.03	2,009,890.57	9,957,503.90	16,293,369.50	22,105,386.33
5	402	Incentive Wages	-	5,348.03	-	7,045.38	12,393.41	1,479,150.00	1,117,200.00	2,153,650.00	4,750,000.00	4,762,393.41
6	403	Share-based Compensation	-	-	-	-	-	1,402,122.91	1,059,021.55	2,041,498.17	4,502,642.63	4,502,642.63
7	410	Travel	1,093.17	9,161.96	1,415.12	11,574.10	23,244.35	77,260.75	46,851.26	147,745.34	271,857.34	295,101.69
8	413	Training	-	-	82.92	2,580.98	2,663.90	43,689.74	21,715.09	99,109.81	164,514.64	167,178.54
9	414	Meals-Travel/Entertain	449.42	2,870.12	425.10	7,084.83	10,829.47	48,174.60	30,207.42	85,280.59	163,662.61	174,492.08
10	416	Meals-OnPremise, OT	-	196.34	-	486.40	682.74	7,511.19	4,156.75	16,329.91	27,997.85	28,680.59
11	453	Computer Software	-	-	89,654.08	-	89,654.08	250,507.56	124,779.31	696,703.44	1,071,990.31	1,161,644.39
12	459	Computer Hardware	-	-	-	-	-	21,773.13	14,176.41	50,421.58	86,371.12	86,371.12
13	460	Warehouse Supplies	-	2,588.60	-	52,716.27	55,304.87	968.44	93.77	1,683.99	2,746.21	58,051.08
14	461	Supplies and Equipment	51.35	837,667.15	46,077.58	(3,175,262.39)	(2,291,466.31)	174,396.65	87,166.32	554,481.00	816,043.97	(1,475,422.34)
15	482	Communication Charges	-	-	-	-	-	258,713.97	195,406.31	376,688.87	830,809.15	830,809.15
16	531	Advertising	-	-	-	-	-	2,371.93	1,791.52	3,453.55	7,617.00	7,617.00
17	546	Consultants/Contracted Svcs	-	1,226,283.78	1,413,822.87	929,156.74	3,569,263.39	539,054.47	316,014.71	1,139,051.09	1,994,120.27	5,563,383.66
18	547	Investor Relations	-	-	-	-	-	204,070.08	154,138.96	297,119.44	655,328.48	655,328.48
19	560	Assoc Company Labor	-	-	-	-	-	72,730.50	56,565.40	139,452.46	268,748.36	268,748.36
20	561	Assoc Company Labor Ovhd	-	-	-	-	-	26,795.21	20,214.84	49,967.48	96,977.53	96,977.53
21	562	Assoc Company Vehicle Clrg	-	-	-	-	-	6,657.58	4,004.33	12,332.23	22,994.14	22,994.14
22	565	Assoc Company Other	-	-	-	-	-	160,033.04	124,395.53	224,005.00	508,433.57	508,433.57
23	568	Assoc Company G&A	-	-	-	-	-	1,317,207.84	944,177.60	2,113,865.15	4,375,250.59	4,375,250.59
24	610	Rent	-	167,505.49	110,929.39	117,929.54	396,364.42	1,974,402.42	1,353,749.89	2,282,647.20	5,610,799.51	6,007,163.93
25	611	Questar Center Parking	-	21,340.00	9,450.00	11,300.00	42,090.00	38,820.32	28,681.26	58,621.24	126,122.81	168,212.81
26	620	Contributions and Donations	-	-	-	-	-	902.06	492.72	2,065.60	3,460.38	3,460.38
27	621	Director Fees & Meetings	-	-	-	-	-	593,926.44	448,591.84	864,759.95	1,907,278.24	1,907,278.24
28	622	Director Expenses	-	-	-	-	-	9,949.69	7,514.99	14,486.80	31,951.47	31,951.47
29	624	Mark to Market	-	-	-	-	-	(13,227.17)	(24,814.57)	38,041.74	-	-
30	628	Dues, Publications, Subscriptions	-	-	-	-	-	72,155.46	53,330.54	108,140.64	233,626.64	233,626.64
31	629	Postage & Express	-	77.91	-	182,264.40	182,342.31	8,740.38	4,590.80	33,978.51	47,309.69	229,652.00
32	635	Licenses, Permits and Fees	-	-	7,148.93	550.00	7,698.93	30,017.77	21,997.07	46,967.75	98,982.59	106,681.52
33	641	Regulatory Fees/Expense	-	-	-	-	-	96.27	75.48	136.00	307.75	307.75
34	642	Insurance & Bonding	-	(73,205.83)	821,556.13	(46,900.95)	701,449.35	7,364.11	5,562.11	10,722.19	23,648.41	725,097.76
35	644	Bad Debts	-	-	-	-	-	6,053.07	4,571.88	8,813.30	19,438.25	19,438.25
36	645	Third Party Claims	-	-	3,093.82	-	3,093.82	8,446.76	6,622.83	11,932.32	27,001.91	30,095.73
37	650	Long-term Disability	-	7,500.00	-	21,714.39	29,214.39	-	-	-	-	29,214.39
38	651	Recognition Outstanding Service I	-	-	-	-	-	822.70	463.16	1,421.25	2,707.11	2,707.11
39	652	Employee Benefits-WC&GPL	-	-	2,317.00	-	2,317.00	-	-	-	-	2,317.00
40	653	Employee Benefits-Medical	-	-	1,296,736.48	-	1,296,736.48	137.68	56.89	382.53	577.10	1,297,313.58
41	654	Employee Benefits-Life Insur	-	-	10,188.90	-	10,188.90	-	-	-	-	10,188.90
42	655	Employee Benefits-Retirement	-	43,813.28	7,474,482.06	116,243.50	7,634,538.84	(73,082.49)	(30,195.76)	(203,055.53)	(306,333.78)	7,328,205.06
43	656	Employee Benefits-Empl Invest Pl	-	-	-	-	-	4,300.97	1,777.05	11,949.99	18,028.00	18,028.00
44	657	Employee Benefits-Miscellaneous	-	-	19,655.46	-	19,655.46	-	-	-	-	19,655.46
45	659	Deferred Comp - (Non-Qualified)	-	-	-	-	-	(16.12)	(12.18)	(23.48)	(51.78)	(51.78)
46	666	Depreciation	-	-	-	-	-	205,781.89	155,428.14	299,617.43	660,827.47	660,827.47
47	673	Bank Service Charge	-	-	16,219.93	-	16,219.93	77,971.09	58,891.46	113,526.31	250,388.86	266,608.79
48	677	Interest Expense - Assoc Compan	-	-	6,855.26	-	6,855.26	-	-	-	-	6,855.26
49	687	Amortization of Debt Expense	-	-	-	-	-	160,347.88	121,110.54	233,467.34	514,925.76	514,925.76
50	710	Federal Income Tax	-	(4,052,239.00)	54,674,622.00	(19,968,142.00)	30,654,241.00	-	-	-	-	30,654,241.00
51	715	State Income Tax	-	288,501.00	586,560.00	(398,671.00)	476,390.00	-	-	-	-	476,390.00
52	749	Property Tax	-	-	-	-	-	4,095.01	3,092.96	5,962.36	13,150.32	13,150.32
53	850	Garage Vehicles & Equip	-	2,575.01	65.36	98,484.50	101,124.87	21,139.92	4,821.92	49,467.54	75,429.38	176,554.25
54	902	Information Technology	-	-	-	-	-	23,059.09	(28.43)	51,494.62	74,525.28	74,525.28
55	920	Labor Overhead	12,989.77	1,463,527.28	444,667.65	3,569,908.43	5,491,093.13	4,053,188.45	1,882,505.68	9,395,405.00	15,331,099.12	20,822,192.25
56	927	Vehicle Clearing	34.66	219,405.14	10,287.09	604,645.46	834,372.35	45,229.07	11,643.09	123,529.15	180,401.32	1,014,773.67
57	984	Company Services-Other	-	-	87,569.14	-	87,569.14	107,963.24	81,544.49	157,195.04	346,702.77	434,271.91
58	985	Transfer to Affiliates	-	140,202.57	42,293.64	375,617.40	558,113.61	-	-	-	-	558,113.61
58	989	Clearing Credits	-	-	-	(1,035,768.90)	(1,035,768.90)	-	-	-	-	(1,035,768.90)
59	Total Charges to Subsidiaries		28,250.75	2,330,780.34	67,637,303.36	(11,980,036.73)	58,016,297.72	17,786,252.15	10,533,435.49	33,875,277.89	62,194,965.54	120,211,263.26
	2/	Direct Payments to Bal Sheet		21,981,516.54	0	55,496,860.19	77,478,376.73					

1/ Amounts that are paid by corporate departments but are recorded directly on the subsidiaries books as expense rather than allocated, such as outside auditor fees, legal fees, and bank fees .

2/ Direct payments to balance sheet accounts, such as labor overhead items, pension contributions, and insurance premiums that later are charged to expense or capital accounts through other allocations or amortizations.

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.02
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.02 As a follow-up to the information provided in response to DPU 2.5, it appears that a large portion of the increase in the total corporate overhead is due to the variation in the amount of Federal and State tax. (2013 $45.1 million, 2014 $68.3 million, 2015 $119.2 million). Please explain the reason for the difference in the tax allocation for the three years under review and how the Federal and State tax amounts are allocated to the operating entities.

Answer: Federal and state taxes are allocated to the operating entities based on their proportionate share of net tax (gross tax less credits).

Questar Corporation files its federal and most state taxes on a consolidated basis. Tax payments, including quarterly estimates and finalized annual payments, are generally made at the corporate level and then billed to the individual entities for their proportionate share. The amounts reported in DPU 2.05 represent the amount billed to the various entities during the calendar year for payments of current federal and state obligations.

2013 is low because approximately $34,000,000 of the required payments for 2013 federal income taxes was satisfied as a result of the application of overpayments from the 2012 federal income tax return.

2015 is high because the federal government did not approve 50% bonus depreciation until December 18th, 2015. As fourth quarter estimated payments were due on December 15th, these payments were made based on assumptions that did not include 50% bonus depreciation. As this resulted in a substantial overpayment, Questar Corporation filed for a refund of $45,000,000 on January 5, 2016.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.03
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.03 In reference to the tax allocation amounts identified in the previous question, please explain how these allocation amounts correspond with the corporate income tax amounts identified in the Questar Corp 10-K report. (2013 $101.3 million, 2014 $125.9 million, 2015 $110.6 million).

Answer: The tax amounts in the 10-K report include expenses for current and deferred federal and state income taxes while the above referenced direct charges include only current federal and state income tax payments. Inherent in this process are timing differences between the date a tax expense is incurred and the date it is paid. The 10-K report also includes current and deferred taxes for Questar Corporation, while the above referenced direct charges do not.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.04
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.04 As a follow-up to the information provided in response to DPU 2.5, please explain why the 2013 direct allocated charges to Questar Gas for Federal and State taxes are negative amounts.

Answer: The 2013 direct charges are negative because they were impacted by a net operating loss carryover from 2012. The net operating loss originated in 2011 due to 100% bonus depreciation.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.05
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.05 As a follow-up to the information provided in response to DPU 2.5, please provide additional information concerning the change in total corporate overhead charges in the following areas. (Note that the amount in 2013 has been recalculated from the original spreadsheet. Individual line item totals for column L and M have been corrected).

	2013	2014	2015
Labor	24,229,967	25,754,006	28,838,351
Consultants/Contracted Services	2,526,732	3,532,993	4,761,763
Labor Overhead	23,230,534	19,372,536	24,440,175

Answer: In order to have an accurate analysis of the change in the costs requested above, an adjustment needs to be made for a change in accounting coding procedure. Prior to 2015, shared service costs were all coded to Associated Company G&A, regardless of the type of costs. In 2015, to improve transparency, the Company changed from summarizing the corporate costs in a separate transaction code to recording the corporate costs in their original transaction code on the affiliate books. Thus, amounts that in prior years were charged to Associated Company (separate transaction code) are now reported as Labor, Labor Overhead, etc… in 2015. Note: No change was made to the allocations. Below is a revised table:

	2013	2014	Change from 2013		2015	Change from 2014	
Labor	24,229,967	25,754,006	1,524,039		28,838,351	3,084,345	
Associated Company Labor	1,814,119	1,686,975	(127,144)		-	(1,686,975)	
	26,046,099	27,442,995	1,396,896	5%	28,838,351	1,395,356	5%
Consultants/Contracted Services	2,526,732	3,532,993	1,006,261		4,761,763	1,228,770	
Associated Company Consultants/Contracted Services	550,175	522,425	(27,750)		-	(522,425)	
	3,076,907	4,055,418	978,511	32%	4,761,763	706,345	17%
Labor Overhead	23,230,534	19,372,536	(3,857,998)		24,440,175	5,067,639	
Associated Company Labor Overhead	1,558,686	1,201,481	(357,205)		-	(1,201,481)	
	24,789,220	20,574,017	(4,215,203)	-17%	24,440,175	3,866,158	19%

The increase in Labor of 5% from 2013 to 2014 was due to annual merit increases of 3% and an increase of 10 employees at Questar.

For the 2014-2015 change, 3% of the change was due to annual merit increases. The employee count increased by an average of eight employees in 2015 for the remainder of the increase.

The increase in Consultant charges from 2013 to 2014 was due to the following increases:

Auditor fees	$200,000
Contract programmers	$100,000
Financial advisors	$100,000
Office machine contracts	$250,000
Compensation consultants	$100,000
Legal counsel	$120,000
Miscellaneous	$109,000

For 2015, the following increases occurred:

Auditor fees	$245,000
Legal counsel	$60,000
Benefits consultants	$60,000
Executive search	$125,000
Contract programmers	$75,000
Miscellaneous	$141,000

Labor Overhead decreased from 2013 to 2014 due to lower pension expense. Questar Corporation's pension expense decreased $5,040,000 in 2014 as compared to 2013. The decrease was partially offset by higher medical insurance costs.

Labor Overhead increased from 2014 to 2015 due to higher pension expense and increased medical costs. Questar Corporation's pension expense increased $1,200,000 in 2015. Medical costs increased $900,000. Overhead associated with the 5% increase in labor was $1,050,000. Increases in time off and miscellaneous benefits caused the remainder of the increase.

Prepared by: Mike Rawlins, Manager General Accounting, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.06
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.06 As a follow-up to the narrative information provided in response to DPU 2.05, please explain the difference between the total direct charges identified on line 58 and the Direct Payment amount identified on line 59.

Answer: Generally, Line 58 includes the Corporate overhead charges that were paid or expensed for the year.

Generally, Line 59 is the Corporate overhead charges that were capitalized.

Prepared by: Mike Rawlins, Manager General Accounting, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.07
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.07 As a follow-up to the information provided in response to DPU 2.5, please explain why in 2015 there were $5,957,309 in employee benefit costs (652 – 657) that were directly allocated to Wexpro. This amount represents 96.5% of the total allocation for 2015.

Answer: Wexpro receives employee benefit costs from the Corporation in a different manner than Questar Gas and Questar Pipeline. Wexpro does not use the Peoplesoft system and therefore all of the allocated charges to Wexpro are coded in 652-657. The employee benefit costs for Questar Pipeline and Questar Gas are included in the Direct Payments amounts on line 67.

Prepared by: Mike Rawlins, Manager General Accounting, Questar Gas Company

EXHIBIT ____ (LK-25)

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.02
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.02 As a follow-up to the information provided in response to DPU 2.5, it appears that a large portion of the increase in the total corporate overhead is due to the variation in the amount of Federal and State tax. (2013 $45.1 million, 2014 $68.3 million, 2015 $119.2 million). Please explain the reason for the difference in the tax allocation for the three years under review and how the Federal and State tax amounts are allocated to the operating entities.

Answer: Federal and state taxes are allocated to the operating entities based on their proportionate share of net tax (gross tax less credits).

Questar Corporation files its federal and most state taxes on a consolidated basis. Tax payments, including quarterly estimates and finalized annual payments, are generally made at the corporate level and then billed to the individual entities for their proportionate share. The amounts reported in DPU 2.05 represent the amount billed to the various entities during the calendar year for payments of current federal and state obligations.

2013 is low because approximately $34,000,000 of the required payments for 2013 federal income taxes was satisfied as a result of the application of overpayments from the 2012 federal income tax return.

2015 is high because the federal government did not approve 50% bonus depreciation until December 18th, 2015. As fourth quarter estimated payments were due on December 15th, these payments were made based on assumptions that did not include 50% bonus depreciation. As this resulted in a substantial overpayment, Questar Corporation filed for a refund of $45,000,000 on January 5, 2016.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.03
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.03 In reference to the tax allocation amounts identified in the previous question, please explain how these allocation amounts correspond with the corporate income tax amounts identified in the Questar Corp 10-K report. (2013 $101.3 million, 2014 $125.9 million, 2015 $110.6 million).

Answer: The tax amounts in the 10-K report include expenses for current and deferred federal and state income taxes while the above referenced direct charges include only current federal and state income tax payments. Inherent in this process are timing differences between the date a tax expense is incurred and the date it is paid. The 10-K report also includes current and deferred taxes for Questar Corporation, while the above referenced direct charges do not.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

P.S.C.U. Docket No. 16-057-01
Data Request No. 5.04
Requested by Division of Public Utilities
Date of QGC Response April 28, 2016

DPU 5.04 As a follow-up to the information provided in response to DPU 2.5, please explain why the 2013 direct allocated charges to Questar Gas for Federal and State taxes are negative amounts.

Answer: The 2013 direct charges are negative because they were impacted by a net operating loss carryover from 2012. The net operating loss originated in 2011 due to 100% bonus depreciation.

Prepared by: Bob Maxwell, Director of Tax Accounting, Questar Corporation

EXHIBIT ____ (LK-26)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.36
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Corporate Structure and Affiliate Transactions

OCS 2.36 Please provide a copy of all studies and/or analyses that address the utilization of Questar Corporation and/or Questar Gas as Dominion's Western Region hub and/or the establishment of a "new" Western Region operating headquarters in Salt Lake City (Application at 25 and Leopold Direct at 13).

Answer: There are no formal "studies and/or analyses". The strategic rationale behind the western hub strategy is based on Dominion's general understanding of the US energy landscape given current and future potential environmental regulations and other factors, and how Dominion believes that will fit with the Questar Merger and business model.

Prepared by: Thomas Wohlfarth, Senior Vice President, Regulatory Affairs, Dominion Resources Services, Inc.

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.17
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.17 Reference Joint Notice and Application ¶ 58b, p. 25.

a. Please describe the new Western Region operating headquarters in detail, including estimated staffing levels, costs, purpose, goals and a project timeline for the headquarters.

b. Provide all studies, analyses and plans for this Western Region operating headquarters.

Answer: a.-b. See the response to OCS 2.36. Following the Merger, Questar's existing headquarters in Salt Lake City will become Dominion's Western Region operating headquarters.

Prepared by: Lisa S. Booth, Deputy General Counsel, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-27)

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.45
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.45 Reference the Direct Testimony of Craig C. Wagstaff p. 7:89 – 90 and 103 – 104. In lines 103 – 104 it is mentioned that Questar Gas employees will "remain" local, where in lines 89 – 90 it is mentioned that Questar Gas will "continue" to have local employees.

a. How many local employees does Questar Gas currently have?
b. How many employees will remain local after Dominion's purchase and in the subsequent 5 years after the merger?
c. If less employees remain local, wouldn't total donated hours and ability to service and participate on boards of various charitable organizations be diminished? If not, please explain why.

Answer:
a. Please see Joint Application Exhibit 1.15 page 2.
b-c. It is anticipated that Dominion Questar Gas employees will be local now and in the future. Participations on boards and charitable organizations will not be diminished.

Prepared by: Kelly B Mendenhall, General Manager, Regulatory Affairs, Questar Gas Company

P.S.C.U. Docket No. 16-057-01
Data Request No. 6.67
Requested by Division of Public Utilities
Date of QGC Response May 26, 2016

DPU 6.67 Of the 347 positions shown in Exhibit 1.15 page 1, what is the best estimate of:

a. How many will be eliminated and replaced by Dominion employees.
b. How many will be eliminated and replaced outsourced resources?

Answer: a.-b. Please see the responses to DPU 4.09 and WPSC 2.12, as well as the First Supplement to the Joint Application filed on May 19, 2016 in Wyoming Docket Nos. 30010-150-GA-16 and 30025-1-GA-16 (see specifically Section VI).

Prepared by: Karla Haislip, Merger & Acquisition Project Director, Dominion Resources Services, Inc.

EXHIBIT ____ (LK-28)

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.55
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Staffing, Employee Welfare, Bargaining Unit

OCS 2.55 Please describe all plans to integrate the employees of Questar into the Dominion employee benefits and welfare plans, including the pension plan, other post-retirement and post- employment benefit plans, 401(k) and other savings plans, vision and dental plans, life insurance and disability (short term and long term) plans, and paid time off.

Answer: At this time, Dominion has no plans to change Questar's employee benefit and welfare plans, including pension, other post-retirement and post-employment benefits plans, 401(k) and other savings plans, vision and dental plans, life insurance and long term disability plans through the continuation period set forth in the Merger Agreement. Dominion is currently analyzing transition options for employee benefit plans after the continuation period. At this time, decisions have not been finalized.

Dominion is still evaluating the options for transition of time off policies, including the timing of any changes and details, which would include the short term disability policy transition. At this time, decisions have not been finalized.

Prepared by: Jennifer C. Wiggins, HR Projects & Strategic Change Manager

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.58
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Staffing, Employee Welfare, Bargaining Unit

OCS 2.58 Provide a copy of all studies, analyses, and/or quantifications of integrating the employees of Questar into the Dominion employee benefits and welfare plans.

Answer: Dominion is currently analyzing transition options for employee benefit plans after the continuation period set forth in the Merger Agreement with the assistance of our actuary, Willis Towers Watson. At this time, decisions have not been finalized. Dominion will make a copy of a preliminary analysis available as OCS 2.58 Highly Confidential Attachment 2 pursuant to Utah Admin. Code R746-100-16. The document will be available for review, upon reasonable notice, at Questar Gas' offices for those parties who agree in writing to comply with R746-100-16.

Additionally, internal analysis has been conducted to review transition of Paid-Time-Off Plans. Dominion is still evaluating the options for transition of time off policies, including the timing of any changes and details. See OCS 2.58 Attachment 1.

At this time, no decisions have been made and analysis is ongoing.

Prepared by: Jennifer C. Wiggins, HR Projects & Strategic Change Manager, Dominion Resources

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 2,884.62		
100% Sick	$ 3,846.15		subject to refresh
70% Sick	$ 14,807.69		subject to refresh
PTO		$ 2,596.15	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 24,038.46**	**$ 21,634.62**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 26,923.08	$ 22,211.54	
75,000/year employee			
Vacation	$ 4,326.92		
100% Sick	$ 5,769.23		subject to refresh
70% Sick	$ 22,211.54		subject to refresh
PTO		$ 3,894.23	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 36,057.69**	**$ 32,451.92**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 40,384.62	$ 33,317.31	
100,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 7,692.31		subject to refresh
70% Sick	$ 29,615.38		subject to refresh
PTO		$ 5,192.31	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 48,076.92**	**$ 43,269.23**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 53,846.15	$ 44,423.08	

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 2,884.62		
100% Sick	$ 7,692.31		subject to refresh
70% Sick	$ 12,115.38		subject to refresh
PTO		$ 4,230.77	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 25,192.31**	**$ 23,269.23**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 28,076.92	$ 23,846.15	
75,000/year employee			
Vacation	$ 4,326.92		
100% Sick	$ 11,538.46		subject to refresh
70% Sick	$ 18,173.08		subject to refresh
PTO		$ 6,346.15	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 37,788.46**	**$ 34,903.85**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 42,115.38	$ 35,769.23	
100,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 15,384.62		subject to refresh
70% Sick	$ 24,230.77		subject to refresh
PTO		$ 8,461.54	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 50,384.62**	**$ 46,538.46**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 56,153.85	$ 47,692.31	

ANNUALIZED VALUE OF TIME OFF POLICIES	**Dominion**	**Questar**	
50,000/year employee			
Vacation	$ 3,846.15		
100% Sick	$ 11,538.46		subject to refresh
70% Sick	$ 9,423.08		subject to refresh
PTO		$ 5,000.00	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 27,307.69**	**$ 24,038.46**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 30,192.31	$ 24,615.38	
75,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 17,307.69		subject to refresh
70% Sick	$ 14,134.62		subject to refresh
PTO		$ 7,500.00	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 40,961.54**	**$ 36,057.69**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 45,288.46	$ 36,923.08	
100,000/year employee			
Vacation	$ 7,692.31		
100% Sick	$ 23,076.92		subject to refresh
70% Sick	$ 18,846.15		subject to refresh
PTO		$ 10,000.00	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 54,615.38**	**$ 48,076.92**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 60,384.62	$ 49,230.77	

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 3,846.15		
100% Sick	$ 15,384.62		subject to refresh
70% Sick	$ 6,730.77		subject to refresh
PTO		$ 6,346.15	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 28,461.54**	**$ 25,384.62**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 31,346.15	$ 25,961.54	
75,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 23,076.92		subject to refresh
70% Sick	$ 10,096.15		subject to refresh
PTO		$ 9,519.23	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 42,692.31**	**$ 38,076.92**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 47,019.23	$ 38,942.31	
100,000/year employee			
Vacation	$ 7,692.31		
100% Sick	$ 30,769.23		subject to refresh
70% Sick	$ 13,461.54		subject to refresh
PTO		$ 12,692.31	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 56,923.08**	**$ 50,769.23**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 62,692.31	$ 51,923.08	

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 3,846.15		
100% Sick	$ 19,230.77		subject to refresh
70% Sick	$ 4,038.46		subject to refresh
PTO		$ 6,346.15	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 29,615.38**	**$ 25,384.62**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 32,500.00	$ 25,961.54	
75,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 28,846.15		subject to refresh
70% Sick	$ 6,057.69		subject to refresh
PTO		$ 9,519.23	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 44,423.08**	**$ 38,076.92**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 48,750.00	$ 38,942.31	
100,000/year employee			
Vacation	$ 7,692.31		
100% Sick	$ 38,461.54		subject to refresh
70% Sick	$ 8,076.92		subject to refresh
PTO		$ 12,692.31	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 59,230.77**	**$ 50,769.23**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 65,000.00	$ 51,923.08	

25 Years

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 4,807.69		
100% Sick	$ 25,000.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 6,538.46	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 32,307.69**	**$ 25,576.92**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 35,192.31	$ 26,153.85	
75,000/year employee			
Vacation	$ 7,211.54		
100% Sick	$ 37,500.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 9,807.69	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 48,461.54**	**$ 38,365.38**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 52,788.46	$ 39,230.77	
100,000/year employee			
Vacation	$ 9,615.38		
100% Sick	$ 50,000.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 13,076.92	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 64,615.38**	**$ 51,153.85**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 70,384.62	$ 52,307.69	

30 Years

ANNUALIZED VALUE OF TIME OFF POLICIES	Dominion	Questar	
50,000/year employee			
Vacation	$ 5,769.23		
100% Sick	$ 25,000.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 6,538.46	
STD (after 6 months service)		$ 17,307.69	
Dependent Care	included in sick		
Holiday	$ 2,307.69	$ 1,730.77	
Personal Volunteer	$ 192.31		
Value	**$ 33,269.23**	**$ 25,576.92**	
Parental Leave	$ 2,884.62		
Bereavement	mgmt discretion	$ 576.92	per occurance
	$ 36,153.85	$ 26,153.85	
75,000/year employee			
Vacation	$ 8,653.85		
100% Sick	$ 37,500.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 9,807.69	
STD (after 6 months service)		$ 25,961.54	
Dependent Care	included in sick		
Holiday	$ 3,461.54	$ 2,596.15	
Personal Volunteer	$ 288.46		
Value	**$ 49,903.85**	**$ 38,365.38**	
Parental Leave	$ 4,326.92		
Bereavement	mgmt discretion	$ 865.38	per occurance
	$ 54,230.77	$ 39,230.77	
100,000/year employee			
Vacation	$ 11,538.46		
100% Sick	$ 50,000.00		subject to refresh
70% Sick	$ -		subject to refresh
PTO		$ 13,076.92	
STD (after 6 months service)		$ 34,615.38	
Dependent Care	included in sick		
Holiday	$ 4,615.38	$ 3,461.54	
Personal Volunteer	$ 384.62		
Value	**$ 66,538.46**	**$ 51,153.85**	
Parental Leave	$ 5,769.23		
Bereavement	mgmt discretion	$ 1,153.85	per occurance
	$ 72,307.69	$ 52,307.69	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF AMERICAN	)	
ELECTRIC POWER COMPANY, INC., KENTUCKY	)	
POWER COMPANY AND LIBERTY UTILITIES CO.	)	**CASE NO. 2021-00481**
FOR APPROVAL OF THE TRANSFER OF OWNERSHIP	)	
AND CONTROL OF KENTUCKY POWER COMPANY	)	

Exhibit DB-R2

DIMITRY BALASHOV

ON BEHALF OF

LIBERTY UTILITIES CO.

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Energy Corporation for Approval of a Transaction by which Wisconsin Energy Corporation Would Acquire All of the Outstanding Common Stock of Integrys Energy Group, Inc.	)	Docket No.:

DIRECT TESTIMONY OF
JOHN J. REED IN SUPPORT OF APPLICATION
BY WISCONSIN ENERGY CORPORATION

I. INTRODUCTION AND PURPOSE

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

A. My name is John J. Reed. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric") and CE Capital, Inc. located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Wisconsin Energy Corporation ("WEC").

Q. Please describe your educational background and professional experience in the energy and utility industries.

A. I have more than 35 years of experience in the energy industry, and have worked as an executive in, and consultant and economist to, the energy industry. Over the past 26 years, I have directed the energy consulting services of Concentric, Navigant Consulting, and Reed Consulting Group. I have served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients, including Wisconsin regulated utilities, and have provided expert testimony on regulatory, economic, and financial matters on more than 150 occasions before the Federal Energy Regulatory Commission ("FERC"), Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. My background is presented in more detail in Ex.-WEC-Reed-1: Experience Statement and Testimony Listing of John J. Reed.

Q. Please describe Concentric's and CE Capital's activities in energy and utility engagements.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America. CE Capital is a fully registered broker-dealer securities firm specializing in merger and acquisition activities. As CEO of CE Capital, I hold several securities licenses that cover all forms of securities and investment banking activities.

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

A. The purpose of my testimony is to address how WEC's proposed acquisition of Integrys Energy Group, Inc. ("Integrys") (the "Transaction") is in the best interests of utility customers, investors and the public. Specifically, I will address three primary areas: (1) recent industry trends and economic and financial market conditions that have driven consolidation within the utility industry, the key drivers of consolidation and how the proposed Transaction is consistent with that current market context; (2) the expected benefits of the proposed Transaction to the customers and investors of WEC and Integrys (collectively the "Companies"), and to the general public; and (3) why the Transaction should be approved by the Wisconsin Public Service Commission (the "Commission") as proposed.

Q. Did Concentric or CE Capital provide any advisory services to the proposed Transaction before it was announced?

A. No. We have been retained as consultants and experts to assist in the approval process for the Transaction.

Q. How is the remainder of your testimony organized?

A. Section II of my testimony provides a brief overview of the Transaction, including the objectives of the Transaction and the commitments and conditions made by WEC. Section III provides an overview of recent utility industry trends, to provide context and insight into the underlying strategic, economic and regulatory drivers that encourage transactions such as the proposed Transaction. Additionally, I present an overview of utility industry consolidation over the long-term, and show how that trend has changed the utility sector over time. Section IV reviews the reaction of the Credit Rating Agencies to consolidation in the utility industry in general, and WEC, Integrys, their operating companies, and the Transaction in particular. Section V summarizes my understanding of the Commission's standard for approving a merger like this Transaction. Section VI describes the specific strategic, customer, and financial benefits of the Transaction. Section VII explains how the Transaction satisfies the Commission's standard. Section VIII provides my conclusions and recommendations.

II. OVERVIEW OF THE TRANSACTION

Q. Please briefly describe the Transaction.

A. On June 22, 2014, WEC and Integrys (collectively, the "Companies") entered into an agreement pursuant to which WEC would acquire 100% of the outstanding common stock of Integrys. Upon completion of the Transaction, the combined company will be called WEC Energy Group. All utility subsidiaries of WEC and Integrys (except Upper Peninsula Power Company),[1] including Wisconsin Electric Power Company ("WEPCO") and Wisconsin Gas LLC ("WG") (both doing business as "We Energies"), Wisconsin Public Service Corporation ("WPS"), The Peoples Gas Light and Coke Company ("Peoples Gas"), North Shore Gas Company ("North Shore Gas"), Minnesota Energy Resources Corporation ("MERC"), and Michigan Gas Utilities Corporation ("MGU") will remain as subsidiaries of WEC Energy Group. As discussed below, WEC Energy Group will continue to hold 60.31% ownership in American Transmission Company LLC ("ATC").

Integrys shareholders will receive total consideration of $71.47 per share which, combined with the assumption of Integrys debt and excluding non-regulated businesses

[1] Integrys is in the late stages of selling UPPCO to Balfour Beatty Infrastructure Partners LP.

represents a premium of 55% over Integrys' estimated 2015 rate base.[2] The total value of the Transaction is estimated at $9.1 billion: $5.8 billion for Integrys shares and $3.3 billion of assumed Integrys debt. WEC will finance the Transaction by issuing new WEC stock and by WEC issuing approximately $1.5 billion in new acquisition debt.

In performing the due diligence necessary to properly consider the proposed Transaction, WEC engaged Standard & Poor's ("S&P") and Moody's Investor Services ("Moody's") (collectively with Fitch Ratings ("Fitch"), the "Credit Rating Agencies") to review the terms of the Transaction and to confirm the expected effect of the Transaction on the credit metrics and credit ratings of the combined company.[3] As noted in the Application and as discussed in more detail in Section III of my testimony, the Credit Rating Agencies have evaluated the impact of the Transaction on credit quality, and have reaffirmed the current credit ratings for the operating utility subsidiaries after the finalization of the Transaction. While Moody's has changed the ratings "outlook" for WEC (the parent company) to negative and Fitch has changed WEC's credit rating to "Rating Watch Negative" due to near-term concerns about additional debt at the holding company level, Moody's has also indicated that the long term effect of the Transaction is likely to be beneficial, particularly for Integrys.

Each of the boards of directors of WEC and Integrys gave its unanimous approval for its company's participation in the Transaction. Both WEC and Integrys will schedule shareholder votes to seek approval of the Transaction from their common equity shareholders. Both shareholder votes are expected to be held in the fourth quarter of

[2] Integrys shareholders will receive 1.128 WEC shares plus $18.58 in cash for each Integrys share. See, *Wisconsin Energy to Acquire Integrys Energy Group*, Company Presentation, June 2014, at 15 and 26. Valuation based on June 20, 2014 closing price.

[3] WEC engaged S&P and Moody's prior to the merger and compensated them for their reviews. Integrys provided consent for doing the analysis.

2014. The Companies each expect its shareholders will find this proposed Transaction to be in the Company's best interests and will vote to approve the Transaction.

Please refer to the testimony of WEC's witness Scott Lauber for a more detailed discussion of the Transaction.

Q. What are the key characteristics of the combined WEC Energy Group?

A. WEC Energy Group will be one of the largest utility holding companies in the country, with a combined rate base of about $17 billion, serving approximately 4.3 million customers across Wisconsin, Illinois, Michigan and Minnesota. On a consolidated basis, WEC Energy Group will rank approximately 14th among public utilities in the country in terms of market value and 15th in terms of gas and electric customers. The combined company will have approximately 2.8 million gas distribution customers and 1.5 million electric utility customers. Based solely on the gas utility customer count, WEC Energy Group will be larger than all but seven gas utilities nationally.

Integrys has announced a proposed sale of the retail electricity and natural gas supply portion of Integrys Energy Services, Inc. ("IES") to Exelon Corporation. That divestiture is expected to close no later than the first quarter of 2015. WEC Energy Group will continue to own and operate IES's solar asset development and management business, Trillium CNG, a leading provider of compressed natural gas fueling services, and Integrys Business Support, LLC ("IBS"), a centralized service company that, shortly after the Transaction's closing, will be renamed "WEC Business Services, LLC" ("WBS").On a consolidated basis, WEC Energy Group also will retain a 60.31% ownership stake in American Transmission Company, LLC ("ATC").

As the Companies have stated in their announcement of the Transaction, "[t]he combination of Wisconsin Energy and Integrys brings together two strong and well-regarded utility operators with complementary geographic footprints to create a larger, more diverse Midwest electric and natural gas delivery company with the operational expertise, scale and financial resources to meet the region's future energy needs."[4]

Q. Is WEC seeking recovery of the Transaction's acquisition premium?

A. No. WEC is not seeking the recovery of the acquisition premium from regulators in any state or at the FERC.

Q. Is WEC seeking recovery of its transaction costs?

A. No. To be clear, transaction costs are the various costs and fees incurred in connection with the execution of the Transaction (e.g., banker fees, legal fees, etc.). WEC Energy Group will not seek the recovery of these Transaction costs from any state regulator or the FERC.

Q. Is WEC seeking recovery of transition costs**?**

A. Savings that are realized over time, and the recovery of transition costs necessary to achieve those savings, will be addressed through the future rate case processes in each state.

Q. Is WEC planning any changes in the combined company's presence and workforce in the communities it serves?

A. No. WEC is committed to maintaining a local presence in the communities currently served by the combined company's operating utilities. WEC Energy Group will maintain operational headquarters in the cities of Milwaukee, Green Bay, Chicago and Waukegan.

[4] See, *Wisconsin Energy to acquire Integrys Energy Group for $9.1 billion in cash, stock and assumed debt - creating a leading Midwest electric and gas utility*, Press Release, June 23, 2014.

The corporate headquarters of WEC Energy Group will remain in Wisconsin. WEC is not planning the sort of reductions in force that occur in many corporate consolidations. The vast majority of any reductions in the labor force of WEC Energy Group will occur over time through natural attrition and voluntary separation. As specifically related to labor union employees, as discussed in WEC's application, "[f]or 2 years from the date of closing of the Transaction, any reduction in headcount among employees in Wisconsin who are represented by a labor union will occur only as the result of voluntary attrition or retirement."[5]

Q. Will the Transaction have any near-term impact on rates?

A. No. None of the WEC Energy Group utilities is proposing any changes to rates at this time as a result of the Transaction. As discussed in more detail later in my testimony and in the testimony of Mr. Lauber, this Transaction is not based on expected short-term savings sometimes seen in mergers, which generally have occurred as the result of significant layoffs. Efficiencies are expected to be identified and realized over time, with no meaningful net savings expected in the near term. Savings that are realized over time, and the transition costs necessary to achieve those savings, will be reflected through the future rate case processes in each state.

Q. Will WEC Energy Group have affiliated interest agreements in place governing the sharing of services between regulated and non-regulated operations?

A. Yes. As discussed in more detail in Mr. Lauber's testimony, WEC and its affiliates currently share services pursuant to various agreements approved in the jurisdictions in which they currently operate. Integrys and its operating companies, including IBS, provide services to one another pursuant to their own commission-approved affiliated

[5] See, WEC Application at 5.

interest agreements. WEC is seeking the Commission's approval of a new affiliated interest agreement that reflects the merger and allows WEC and Integrys companies (other than WBS) to provide services to one another where it is in customers' best interests to do so.

Q. Has WEC agreed to any conditions applicable to its majority ownership in ATC?

A. Yes. As discussed WEC Witness Scott Lauber, WEC is committing to the FERC that following the closing of the Transaction, WEC Energy Group will vote its ownership stake in ATC in such a way as to maintain the current diversity of views on the direction and management of ATC.

Q. Please summarize the benefits the Transaction will create.

A. As discussed in more detail in Section VI, below, the Transaction will create a larger, more diversified and financially strong energy company with deep roots in Wisconsin, benefiting customers, employees, shareholders and the communities and region in which it operates. The significant scale of WEC Energy Group will better equip it to compete and maintain its independence in the rapidly changing and capital-intensive energy business. The strong cash flow of the combined company can be prudently invested in needed energy infrastructure, including the environmental retrofits, undergrounding of service lines, gas main replacements and investment in new technologies that are included in Integrys' five-year plan to invest $3.5 billion in infrastructure and operations. Over the long-term, WEC Energy Group's increased financial scale and strength will promote enhanced access to capital to fund the ongoing initiatives of the combined company.

The Transaction will result in increased customer base/composition, geographic, asset (including generation assets), operational and regulatory diversification. This diversification will better enable WEC Energy Group to meet the challenges of a rapidly changing energy industry, through sharing best practices across its operating territories, the ability to benefit from the combined company's large and expert workforce across its system, and the opportunity to create efficiencies over time. The positive impact of diversification and operational opportunities, along with WEC's commitments regarding their active local presence and workforce, will produce significant local and regional economic benefits as compared to either independent operation or as part of another merger with a different acquirer with a different focus.

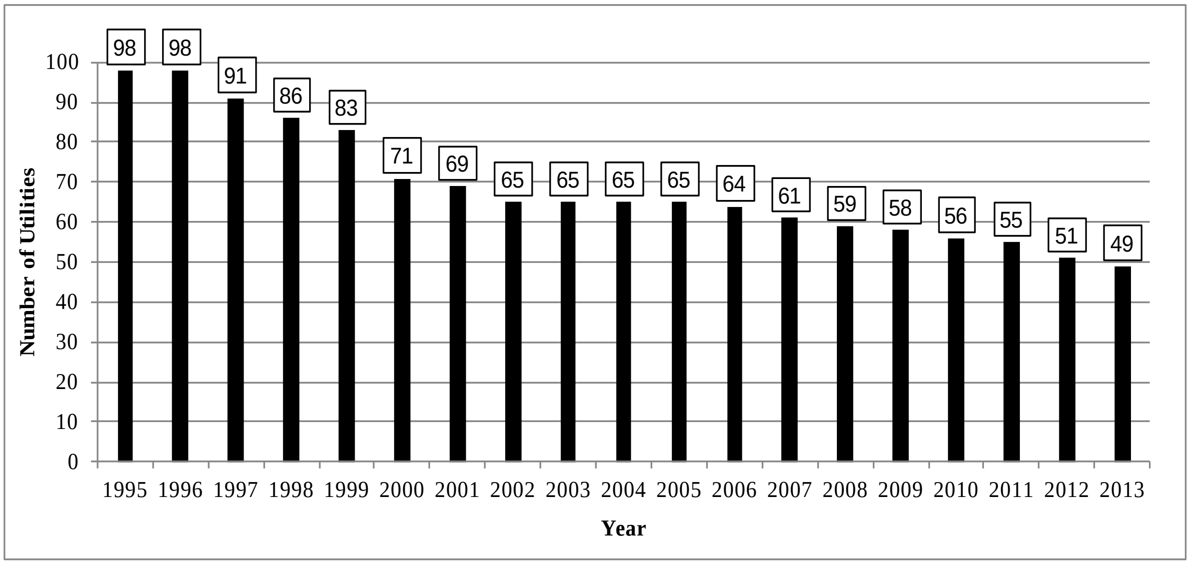
Creating a utility holding company with the strength, scale and breadth that WEC Energy Group will have, will enable it to continue to provide its customers with safe, reliable and affordable utility service, appropriately compensate its shareholders, continue the Companies' long tradition of making significant contributions to the communities they serve, act as a leader in the energy industry and continue to constructively contribute to energy policy in Wisconsin and the nation. Importantly, the Transaction will enable WEC Energy Group to achieve these benefits for customers, investors and the public.

III. RECENT INDUSTRY TRENDS AND UTILITY INDUSTRY CONSOLIDATION

Q. Please describe the state of mergers and acquisitions in the utility industry.

A. The utility industry has been steadily consolidating for some time. As shown in Chart 1, since 1995, the number of electric investor-owned utilities ("IOUs") has declined by 50 percent, from 98 companies at the beginning of 1995 to 49 companies as of December 2013.

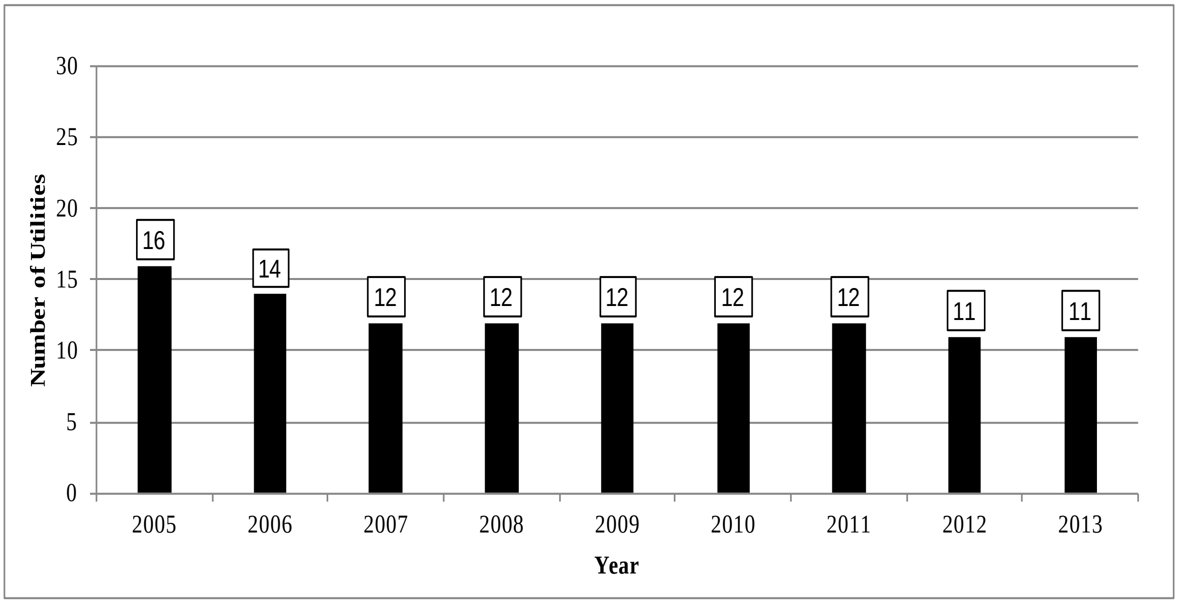
Chart 1: U.S. Investor-Owned Electric Utilities 1995-2013[6]



Similarly, the number of natural gas distribution IOUs has declined by approximately 31 percent, from 16 companies in December 2005 to 11 companies as of December 2013. Moreover, as pointed out by Daniel Fidell, a utility analyst at U.S. Capital Advisors, the merger and acquisition trend from 2004-2011 "typically consisted of a larger electric utility acquiring a smaller gas utility."[7]

[6] Source: EEI 2013 Financial Review, at 41.
[7] "U.S. Capital Advisors breaks down attractive utility M&A targets," SNL Financial, July 9, 2014.

Chart 2: U.S. Investor-Owned Natural Gas Distribution Utilities 2005-2013[8]



Q. What trends in the industry are driving this consolidation?

A. Industry trends such as stagnant demand or declining customer usage and increased capital spending for investments that do not increase the quantities of electricity or natural gas sold (e.g., environmental retrofits on existing electric generators), as well as weak economic conditions over the past several years have stretched utility balance sheets and placed pressure on credit metrics, contributing to utilities seeking strategic mergers to increase their size and improve their overall financial strength.

Current and projected capital needs of utilities are driven by expenditures that are not growth oriented and, absent rate increases, do not produce additional revenues. The magnitude of these investments often requires utilities to seek access to capital markets. At the same time that utilities are facing increased capital requirements, projected market conditions are such that the era of extraordinarily low debt costs, which has benefited all utilities, is likely coming to an end. As interest rates rise and the cost of both debt and

8 Source: Value Line Investment Survey, December edition of each year shown.

equity increase, utilities with stronger balance sheets and higher credit ratings will have access to capital at more favorable terms, all of which will benefit customers and shareholders.

The trend toward industry concentration highlights one important reason that mid-sized investor-owned utilities, such as WEC and Integrys, would consider merging or being acquired. In particular, by becoming part of a larger company, mid-sized companies can continue to compete effectively with larger entities for debt and equity capital to finance their capital needs.

Q. Please explain why growth prospects are more challenging for utilities in the current environment.

A. Electric and natural gas utilities have faced stagnant demand growth in recent years resulting from a combination of weak economic conditions and demand reductions due to energy efficiency and on-site generation measures. In a report issued immediately following the announcement of the Transaction, the utility industry investment analyst for the investment firm Sanford Bernstein highlighted this trend, noting:

> My basic view is that the pressures behind consolidation will remain strong and may be getting stronger. I see those pressures as being stagnant power demand… Over the last five years, I think power demand is down by a percent and yet utilities have been investing in rate base, so they're probably looking at a base of invested capital that could be 10% to 20% higher than it was five years ago.[9]

The declining demand in some jurisdictions and the slow growth in other jurisdictions, combined with general increases in operating costs have placed pressure on utilities' cash flows, balance sheets, and credit metrics.

[9] "With M&A apace in 2014, Bernstein outlines other potential utility M&A combos," SNL Financial, June 27, 2014.

Q. How do capital investment plans affect utilities' financial strength?

A. Utility capital investment plans include significant infrastructure enhancement and environmental compliance components, which often require access to debt or equity markets. Capital investments include replacement of aging infrastructure (e.g., gas mains), environmental upgrades to comply with current and expected government rules and regulations, necessary transmission and distribution expansion for renewable energy integration and system reinforcement, and investments in new and emerging technologies, all of which are necessary to maintain and improve the distribution system. Since infrastructure enhancements and environmental compliance investments do not result in a larger customer base or increased sales, these investments do not generate any incremental revenue to offset the additional capital financing requirements without an increase in customer rates. For smaller and mid-sized electric and natural gas utility companies, the magnitude of these non-revenue producing capital financing requirements can place significant strain on the company's financial position and rates.

Q. How have recent economic conditions affected the utility industry?

A. Economic conditions have been weak in recent years. The severe recession and credit crisis of 2008-2009 has been followed by a period of slow economic growth in the U.S. These weak economic conditions have contributed to stagnant demand growth for electric and natural gas utility companies, while capital investment requirements for utilities have increased. Moody's notes that since the financial crisis, credit quality has been a key factor driving utility mergers[10], as utilities seek strategic combinations that will allow them to attract capital to finance capital investments during a period of weak economic growth and stagnant demand growth.

[10] Moody's Investors Service, "A Rating Agency Perspective on the Utility Industry," June 25, 2012, p. 24.

At the same time, interest rates have risen over the past year, and the expectation among investors is for that trend to continue as the Federal Reserve winds down the extraordinary Quantitative Easing program that has been in place since the financial crisis of 2008-2009.[11] As interest rates rise and the cost of both debt and equity increases, utilities with stronger balance sheets and higher credit ratings will have access to capital on more favorable terms, all of which benefits customers and shareholders

Q. Have mergers and acquisitions reshaped the utility industry?

A. Yes. Industry consolidation has resulted in significant concentration among the largest IOUs. Examples include: Duke Energy Corp/Progress Energy Inc.; Exelon Corp/Constellation Energy, Inc.; Northeast Utilities/NSTAR LLC; and AGL Resources/NICOR. Ongoing industry consolidation has resulted in the formation of much larger utility holding companies over the past decade.

[11] Blue Chip Financial Forecasts, Vol. 33, No. 6, June 1, 2014, at 14.

Q. Is there an expectation that large-scale mergers will continue to dominate the utility industry?

A. No. While large-scale mergers have resulted in the formation of some extremely large utility holding companies, more recent expectations with respect to ongoing industry consolidation have focused on mid-sized companies. Industry analysts project that trend to continue and have identified several mid-sized companies that may be attractive for acquisition. In June 2014, shortly after the announcement of this Transaction, several medium-sized utilities were identified as consolidation candidates, including: UIL Holdings Corp.; Empire District Electric Co.; Portland General Electric Co.; El Paso Electric Co.; IDACORP Inc., Great Plains Energy Inc.; Avista Corp.; Westar Energy Inc.; Pinnacle West Capital Corp.; and ALLETE, Inc.[12]

Q. Are synergies the primary driver of many recent utility mergers?

A. No, frequently this is not the case. Drivers for individual mergers have advanced beyond the search for synergies and operational economies of scale. Recent mergers and acquisitions reflect the importance of geographic diversification and financial strength in the utility industry. For example, in reviewing major utility mergers that have occurred since 2004, of 27 mergers reviewed, 18 mergers were approved without the filing of a comprehensive synergy study supporting the merger. For those 18 examples, drivers other than synergy savings were the primary reasons for the merger. Examples of these types of mergers include the Fortis acquisition of UNS Energy Corp., the Berkshire Hathaway subsidiary, MidAmerican Energy Holdings Co. ("MidAmerican"), acquisition

[12] "With M&A apace in 2014, Bernstein outlines other potential utility M&A combos," SNL Financial, June 27, 2014.

of Nevada Power, the Puget Holdings LLC[13] acquisition of Puget Energy, the TECO Energy acquisition of New Mexico Gas, the Laclede Group, Inc. acquisition of Alabama Gas Corporation, and the AGL Resources acquisition of NICOR Inc.

Q. What were the primary drivers behind each of those transactions?

A. In each case, the dominant purchaser in those transactions was not seeking to capture immediate synergies (i.e., cost savings and economies of scale) through the combination of local operations. Rather, the acquiring company in each of those transactions was seeking to achieve a number of benefits, including increased scale and scope, enhanced access to capital for the acquired utility company, increased funding for infrastructure-related capital expenditures, and diversification (including customer base/composition, geography, assets, including generation assets, and operations). This is very consistent with the drivers behind the Transaction proposed by WEC and Integrys.

Q. Please provide some specific examples of financial and capital investment-related drivers for mergers.

A. The following summarizes the capital investment issues discussed in several of the above transactions:

- MidAmerican indicated that the merger would benefit NV Energy and its customers through increased financial stability, lower debt costs and increased access to capital that would be needed to make new generation and transmission investments.[14]

[13] Puget Holdings LLC was comprised of a group of long-term infrastructure investors including Macquarie Infrastructure Partners.

[14] SNL Energy, Update: “MidAmerican, NV Energy close merger after gaining FERC’s approval,” December 19, 2013.

- Puget Holdings committed to support Puget Energy and its wholly-owned subsidiary, Puget Sound Energy's $5 billion capital program for infrastructure projects to maintain and improve the utility's reliability, in addition to other savings.
- In Fortis's acquisition of UNS Energy, UNS Energy cited the importance of Fortis' financial strength, which would "improve UNS Energy's access to capital to fund the ongoing diversification of its generating fleet as well as other infrastructure investments. Upon closing, Fortis will inject $200 million into UNS Energy to strengthen its balance sheet and help fund the planned purchase of Unit 3 of the natural gas-fired Gila River Power Plant, a transaction that will reduce TEP's [UNS Energy's operating utility] reliance on coal-fired power."[15]
- AGL Resources indicated that it had strong investment-grade credit ratings and substantial financial resources, and that the merger with NICOR would give Northern Illinois Gas a larger financial platform for making investments to maintain safety and improve reliability and customer service.[16]

In each of these examples, the financial strength of the resulting combined company was a significant driver of the rationale for a merger. Likewise, WEC Energy Group will benefit from similar increased financial strength and flexibility.

Q. How do utility companies evaluate the need for increased diversification?

A. Companies examine their operating segments and growth prospects and seek to mitigate and manage the risks associated with those subsidiaries. Risks may be mitigated either through diversification or the acquisition of a company that has a different risk profile.

[15] "UNS Energy Agrees to Be Acquired by Fortis Utility Group; Acquisition Would Strengthen Local Arizona Utilities," UNS Energy Corporation, December 11, 2013.

[16] Docket No. 11-0046, Illinois Commerce Commission, December 7, 2011, Order at 4.

Avista Corp's plan to acquire Alaska Energy Resources Co., TECO Energy's acquisition of New Mexico Gas Company, UIL Holdings purchase of three gas utility companies from Iberdrola, and the Northeast Utilities and NSTAR merger are additional examples of transactions where diversification was a key driver.

- Avista Corp/Alaska Energy Resources - Avista stated that its strategy in this acquisition was to expand and diversify its energy assets.
- TECO Energy/New Mexico Gas Co. - TECO Energy had seen declining revenue resulting from warm weather and low natural gas prices, which depressed coal prices. TECO Energy stated publicly that this Transaction would increase its customer base by 50 percent, provide future growth in an "attractive Sunbelt location"[17], increase the percentage of earnings from regulated operations, and reduce earnings volatility.
- UIL Holdings/Iberdrola gas utilities, Berkshire Gas Co., CT Natural Gas Corp., and Southern Connecticut Gas Co. – UIL, a Connecticut electric utility company, requested authorization to purchase three natural gas utilities in contiguous and complementary locations, without the filing of a synergy study. UIL noted that the merger would create a larger, diversified energy delivery company, with a diversified revenue mix, and differentiated peaking seasons that levelize earnings and cash flow.[18]
- Northeast Utilities/NSTAR – The primary focus of the Northeast Utilities and NSTAR merger, two gas and electric utilities with complementary operating territories, was on the expansion of scope with respect to financial capability,

[17] See, *TECO Energy Announces Agreement to Acquire New Mexico Gas Company*, Press Release, May 28, 2013.

[18] UIL Acquisition of SCG, CNG & The Berkshire Gas Company, Investor Presentation, May 25, 2010.

geographic diversity and best practices, not on the achievement of immediate synergy savings.[19]

Q. What is your conclusion with regard to whether the factors underlying the proposed Transaction are consistent with recent consolidation within the utility industry?

A. My conclusion is that the factors underlying the proposed Transaction are consistent with recent consolidation within the utility industry. In particular, the proposed Transaction combines neighboring utility companies with complementary markets and adjacent service territories, while providing geographic and customer diversification. If the proposed Transaction is approved, customers will receive the benefits of the combined company, while continuing to enjoy local management and a local presence in the communities served by the various operating utilities. Further, as a result of the proposed Transaction, the combined company will have enhanced scale and financial strength, thereby allowing it to compete for capital on reasonable terms to fund the capital investment requirements of the various operating utilities.

IV. REACTIONS OF THE CREDIT RATING AGENCIES

Q. Have credit rating agencies offered any perspective on consolidation in the utility industry?

A. Yes. Both Moody's and S&P expect that utility mergers will continue. In a 2012 presentation, Moody's concluded that the rationale for utility industry consolidation is "compelling", citing several motivating factors: (1) building scale and scope; (2) spreading fixed costs over larger asset platforms; (3) capturing operating efficiencies; (4)

[19] See, Joint Testimony of James J. Judge and David R. McHale, DPU 10-170, Massachusetts Department of Public Utilities, November 24, 2010. I note that pursuant to a change in merger approval standards in Massachusetts during this proceeding, Northeast Utilities and NSTAR filed a supplemental synergy savings analysis that demonstrated expected savings from the merger.

diversification of business and operating risks and geographic and weather exposure; (5) combining complementary operations; (6) generating financing efficiencies/access to capital markets; (7) growth in earnings; (8) addressing rising operating costs; (9) meeting demand for infrastructure-related capital expenditures; and (10) better management of larger projects.[20]

S&P also projects that utility mergers will continue, as utilities seek to create larger, more diverse and more efficient organizations that have better credit profiles and superior access to capital.[21]

Q. What are the primary factors that affect the credit ratings of the parties in merger transactions?

A. Rating agencies look closely at the structure of mergers and acquisitions involving electric and natural gas utility companies to determine the overall effect on credit ratings. To the extent that the acquiring company's balance sheet takes on significant incremental debt as a result of the transaction, or the concessions required by regulators place pressure on cash flow metrics, rating agencies have tended to downgrade the acquired company. Conversely, acquisitions that place the acquired company in a more favorable financial position to be able to meet its ongoing capital needs have resulted in a credit upgrade or the expectation of future increases in credit ratings for the acquired company.

Q. Please provide examples of recent mergers that resulted in improved credit ratings or a positive ratings outlook for the acquired company.

A. There are several recent mergers that have resulted in improved credit ratings or a positive ratings outlook for the acquired company, including mergers that were not based

[20] Moody's Investors Service, "A Rating Agency Perspective on the Utility Industry," June 25, 2012, p. 24.
[21] Standard & Poor's RatingsDirect, "Opportunity for U.S. Regulated Electric Utility Mergers in the U.S. Still Exists," March 12, 2012.

on synergies and cost savings. In most cases, the acquiring company had a stronger credit rating than the acquired company, resulting in a credit rating upgrade or a positive outlook for the acquired company.

- Berkshire Hathaway/NV Energy – The acquisition of NV Energy by MidAmerican Energy Holdings, a subsidiary of Berkshire Hathaway, was based on geographic diversification and enhancing the financial strength of the combined company. S&P and Fitch both upgraded NV Energy following the closing of the acquisition by MidAmerican Energy Holdings. Fitch indicated that "the one-notch upgrade of [NV Energy] and its utility operating subsidiaries ratings and the stable outlook is supported by the increased financial flexibility and lower funding costs afforded [NV Energy] and its subsidiaries by association with a larger, financially strong parent company."[22]
- FirstEnergy/Allegheny - Prior to the merger, Moody's rated FirstEnergy Baa3 and Allegheny as Ba1. After the merger, Moody's upgraded Allegheny to Baa3. Fitch also revised the rating outlook for Allegheny Energy to positive from stable, stating that "Fitch recognizes the strategic benefits of the transaction which would combine geographically contiguous and complementary regulated utilities and competitive businesses."[23]
- WPS Resources/Peoples Energy Corporation – Moody's upgraded Peoples Energy Corporation's senior unsecured debt rating from Baa2 to A3 following the

[22] SNL Financial, "Fitch upgrades NV Energy after MidAmerican acquisition," December 23, 2013.
[23] SNL Financial, "Rating agencies weigh in on FirstEnergy/Allegheny Energy merger," February 11, 2010.

closing of the acquisition. Moody's stated: "The two-notch upgrade for Peoples reflects its new ownership and support by a solid utility parent company."[24]

- <u>Gaz Metro/Central Vermont Public Service</u> – Moody's upgraded Central Vermont Public Service from Baa3 to Baa2 after the merger with Gaz Metro was completed. Moody's offered the following rationale for the upgrade: "The rating changes reflect our expectation for the combined utility to produce financial metrics, including the ratio of cash flow from operations to debt, in the mid to high teens over the intermediate period."[25]

Q. How have regulatory conditions and requirements on mergers and acquisitions affected credit ratings?

A. Some regulators have required merger applicants to provide certain regulatory concessions or commitments that have negative financial implications for the acquired utility. Depending on the magnitude of the conditions and requirements, there can be negative implications for cash flow metrics and other factors that are considered in establishing a company's credit rating. For example, as a result of conditions placed on the Northeast Utilities/NSTAR merger in Connecticut, Moody's downgraded the ratings outlook for Connecticut Light and Power ("CL&P"), citing concerns that the base distribution rate freeze and the agreement to defer recovery of storm costs over a six year period were less credit supportive.[26] Once the merger was completed, Moody's downgraded CL&P from Baa1 to Baa2.[27] Similarly, merger conditions in Massachusetts

[24] Moody's Investors Service, "Moody's upgrades Peoples Energy Corp.," February 21, 2007.
[25] SNL Financial: "Moody's takes diverging views on GMP, CVPS after merger approval in Vermont," June 25, 2012.
[26] SNL Financial: "Moody's lowers outlook on NU's CL&P subsidiary," March 16, 2012.
[27] Moody's Investors Service, "Moody's downgrades NSTAR, NSTAR Electric, and Connecticut Light & Power; affirms NU and its other subsidiaries," April 9, 2012.

resulted in Moody's placing NSTAR Electric on review for possible downgrade. Moody's noted that the four-year rate freeze allowed for storm cost recovery, but deferred that recovery for more than two years. In Moody's view, this could lead to an increase in indebtedness and reduce margins for NSTAR Electric, which would likely weaken credit metrics in the future.[28] After the merger closed, NSTAR Electric was downgraded by Moody's from A2 to A1.[29]

Q. How have the Credit Rating Agencies responded to WEC's proposed acquisition of Integrys?

A. As I noted above, the Credit Rating Agencies evaluated the impact of the Transaction on credit quality, and reaffirmed the current credit ratings for WEC, Integrys and all of the operating utility subsidiaries. The Credit Rating Agencies have generally viewed the Transaction as positive for Integrys and slightly negative over the short-term for WEC (the parent holding company).

Moody's did change its ratings "outlook" from stable to negative for WEC, citing Moody's expectation that the Transaction would cause deterioration in WEC's credit profile as it is acquiring a company with a weaker credit profile in a leveraged transaction. Over the next three years, Moody's notes that the ratios of cash flow from operations before working capital adjustments to debt and retained cash flow to debt for WEC are expected to fall. At the same time, however, Moody's expressed a favorable overall view of the Transaction:

> Upon the completion of the transaction, WEC will benefit from the larger size and the complementary nature of the operations of the combined group in Wisconsin as well as from a more diversified footprint in

[28] SNL Financial: "Moody's places NSTAR ratings on review for downgrade," February 16, 2012.
[29] Moody's Investors Service, "Moody's downgrades NSTAR, NSTAR Electric, and Connecticut Light & Power; affirms NU and its other subsidiaries," April 9, 2012.

> operational and geographical reach. The latter factors Integrys' multi-state operations and its significant natural gas distribution operations in Illinois…[30]

Concurrently, Moody's put the long-term ratings of Integrys under review for upgrade after the company disclosed that it is in the late stages of a competitive process to divest its unregulated retail operations. After Integrys announced that it had reached a definitive agreement to sell IES to Exelon, Moody's commented: "The sale is credit positive for Integrys because it removes a source of cash flow volatility and the risk for large, unexpected demands on liquidity." [31] Finally, Moody's affirmed certain ratings of WEC and Integrys, including their operating utility subsidiaries. Specifically, the ratings outlook for WEPCO and WG is stable.

S&P affirmed its existing ratings for WEC, Integrys and all of the Companies' respective operating utilities. S&P concurrently reduced the outlook of WEC, Integrys and Integrys' subsidiary companies Peoples Gas and North Shore Gas to "negative" from "stable," noting "[d]ue to WEC's plans to fund the Transaction with a combination of debt and common stock, we believe that the company's financial measures could fall to the weaker end of our "significant" financial risk profile category based on our medial volatility table, leaving little cushion for underperformance relative to our forecast."[32] The ratings outlook of WG, WEPCO, and WPS remain stable because, as noted by S&P,

[30] "Moody's changes Wisconsin Energy outlook to negative following Integrys deal," SNL Financial, June 24, 2014.

[31] Moody's Investors Service, "Integrys Sale of Retail Energy Business to Exelon is Credit Positive," July 31, 2014.

[32] "Research Update: Wisconsin Energy And Integry Ratings Affirmed On Announced Merger; Certain Outlooks Revised To Negative From Stable", Standard and Poor's Ratings Direct, June 23, 2014, at 3.

"[r]atings stability for WEPCO, WG, and WPS reflects sufficient regulatory insulation and their stand-alone credit profiles, which would be unaffected by the transaction."[33]

Fitch had a similar reaction to the Transaction, placing WEC on "Rating Watch Negative" due to concern about the need to issue $1.5 billion in new debt at the holding company level to finance the cash portion of the acquisition. Fitch noted that the ratings of the utility operating subsidiaries WEPCO and WG, are unaffected by the Transaction.[34] Concerns among rating agencies regarding additional debt at the holding company are not uncommon after a merger is announced. For example, in the pending merger between Exelon Corp. and Pepco Holdings, Fitch noted that the proposed acquisition would result in a meaningful increase in consolidated leverage compared to Exelon's current and projected stand-alone financial condition.[35] S&P also noted that the New York Public Service Commission was concerned with the level of debt that National Grid was taking on to acquire KeySpan.[36]

My overall conclusion is that any short-term Credit Rating Agency concerns with increased debt at the holding company level to finance a portion of the Transaction is not a concern for the utility operating companies of the planned WEC Energy Group. The Credit Ratings Agencies agree that the Transaction provides long-term benefits through enhanced financial strength of the combined company and geographic/operational diversification that will offset those short-term concerns.

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[33] Ibid., at 6.

[34] "Fitch places Wisconsin Energy on Rating Watch Negative after Integrys deal announcement," SNL Financial, June 25, 2014.

[35] SNL Financial: "Fitch, Moody's, S&P weigh in on Exelon-Pepco deal," May 1, 2014.

[36] SNL Financial: "S&P downgrades National Grid and KeySpan A to A-," August 24, 2007.

V. MERGER APPROVAL STANDARDS

Q. What is your understanding of the merger approval requirements in Wisconsin?

A. The Commission is responsible for the review and approval of any proposed acquisition, transfer or sale of utility holding company voting securities over a certain percentage. Wisconsin Statute 196.795(3) states:

> No person may take, hold or acquire, directly or indirectly, more than 10% of the outstanding voting securities of a holding company, with the unconditional power to vote those securities, unless the commission has determined, after investigation and an opportunity for hearing, that the taking, holding or acquiring is in the best interests of utility consumers, investors and the public. This subsection does not apply to the taking, holding or acquiring of the voting securities of any holding company existing before November 28, 1985, if such holding company is a company which provides public utility service.

Because Integrys is a Wisconsin utility holding company, the Companies' application in this case is requesting that the Commission find WEC's acquisition of Integrys' outstanding voting securities to be in the best interests of utility customers, investors and the public.

Q. Has the commission previously approved similar utility holding company mergers?

A. Yes, it has. In March, 2000, the Commission approved WEC's purchase of the outstanding securities of WICOR, Inc. ("WICOR"), pursuant to a filing those two companies made in July 1999. At the time of the acquisition, both WEC and WICOR were Wisconsin utility holding companies.

In its order approving that acquisition, the Commission noted "The Commission is authorized under Wis. Stat. 196.795 to grant its consent and approval to the application of WEC to acquire 100 percent of the outstanding common stock of WICOR."[37]

[37] See, Final Decision, Docket 9401-Y0-100, Wisconsin Public Service Commission, March 15, 2000, at Finding of Fact 28..

More recently, the Commission approved the purchase of Peoples Energy Corporation of Illinois by Integrys. In its approval of that transaction, the Commission further explained the authority it holds to regulate holding companies, noting:

> When [the merger] conditions are coupled with the statutory authority of the Commission including the Commission's ability to order divestiture, or termination of interest, of the regulated utility from the holding company Wis. Stat. § 196.795(7)(c), the proposed merger can be found to be in the public interest. The Commission may order divestiture if there is clear and convincing evidence that the financial integrity of the utility would be threatened if the utility continued to be affiliated with a holding company that was experiencing financial difficulties. This remedy deals with the unexpected, and as such is an essential part of the set of conditions that protect ratepayers from experiencing undue harm from activities of the holding company and its non-Wisconsin utility affiliates….With the implicit incorporation of the Commission's statutory authority, the conditions and order points contained in this Final Decision are sufficient to reasonably protect the public interest and give approval to the merger transaction.

VI. BENEFITS OF THE TRANSACTION

Q. Please describe the benefits that will result from the Transaction.

A. The Transaction will create benefits to customers, shareholders and the public in the following categories: (1) financial, (2) diversification, (3) operations, (4) long-term efficiencies, and (5) strategic.

Q. Please discuss the financial benefits of the Transaction.

.A. The proposed Transaction will result in a larger combined company with a broader scope and more diversified yet still complementary operations and geography across its utility subsidiaries. As discussed earlier in my testimony, following the Transaction WEC Energy Group is expected to be the 14th largest utility in the country in terms of market value serving approximately 4.3 million customers across Wisconsin, Illinois, Michigan and Minnesota. This increased scale and scope will create a financially stronger company with both greater financial liquidity and improved access to capital markets.

Greater liquidity enables a company to better withstand economic and financial downturns. This important financial strength will also enable WEC Energy Group to compete with other larger companies for capital on reasonable terms and conditions over the long-term.

Q. Is the ability to compete for capital important?

A. Yes. The ability to secure capital on reasonable terms and conditions is critical for all companies, but is highly important for utilities that face increased needs to make capital expenditures associated with improvements to existing infrastructure. The access to and cost of capital directly reflects the financial strength and risk profile of the company. A stronger utility is able to pass along to its customers the benefits of lower-cost debt and assured access to capital markets on reasonable terms. If tight capital markets were to return, this access can be very valuable.

As I noted earlier in my testimony, consolidation in the utility industry was previously driven by the mergers of large companies. Now many small and medium size utility companies are finding that mergers which allow them to increase their size and financial strength are important in order to allow them to continue to have access to capital markets on reasonable terms to finance the ongoing capital needs associated with serving their customers. This is one of the motivations for and benefits of the proposed merger of WEC and Integrys. WE Energies and WPS each have long-term capital expenditure plans which will require them to access the financial markets for many years to come.

Q. Will the Transaction benefit WPS' near-term capital projects?

A. Yes. In the near term, the strong cash flows of the combined company can fund investments in needed energy infrastructure, including environmental retrofits, undergrounding of service lines, gas main replacements and investment in new technologies. WPS is currently making significant investments in environmental retrofits at the Weston 3 power plant, underground service lines in northern Wisconsin and additional technology deployments in the State. After the Transaction is completed, WEC Energy Group may be able to deploy its strong cash flows to fund those types of projects. As a result, WPS may be able to complete more of its planned investment program using internally generated cash flow. The ability to use internally generated cash flow to fund these near-term investments would allow WPS to avoid incremental costs and fees that would otherwise be incurred if it needed to secure financing from the capital markets.

Q. What are the diversification benefits to the Transaction?

A. First, let me explain what diversification is and how it provides benefits to customers and shareholders. Diversification is akin to the concept of "not putting all of your eggs in a single basket". By bringing together two different but complementary entities, one creates a whole that is more valuable and lower risk than the sum of its parts, in terms of its ability to manage its business and create and capture value over the long-term. WEC and Integrys have positioned themselves to do just that with the Transaction.

Based on my review of the terms of the Transaction, and my experience advising utility clients, the Transaction will add diversity by bringing together the Companies' complementary (1) geographies and service territories, (2) customer bases, (3) electric and gas operations, and (4) markets. Diversifying the combined company's business across these areas contributes to the creation of a stronger combined company by enabling it to better manage and balance the business across its operating companies. As I discuss later in my testimony, while no immediate net savings from efficiencies are anticipated, the Transaction unlocks the opportunity for increased efficiencies in operations, purchasing, and corporate services over the long-term. Finally, this diversification will also allow WEC Energy Group to maintain a strong financial position over the long-term.

Q. What operational benefits will the Transaction create?

A. The Transaction will create a combined company with the operational expertise, scale and resources to ensure that Wisconsin customers continue to enjoy safe, reliable and affordable service. The combined company will share best practices in distribution operations, large capital project management, electric generation, gas supply, system reliability and customer service across the various operating companies in Wisconsin, Illinois, Michigan and Minnesota. For example, We Energies has consistently been ranked near the top of its peer group in terms of reliability and customer satisfaction, earning recognition from PA Consulting group for excellence in reliability and from J.D. Power for both residential and business customer satisfaction. Integrys has also been a leader in developing and implementing gas infrastructure modernization projects in an urban environment. These best practices will be shared across WEC Energy Group.

As I noted earlier and as I will discuss in more detail later in my testimony, each of the operating companies will continue as individual utilities; however there will still be opportunities to optimize their joint resources over time. For example, after the completion of the Transaction, there may be opportunities for joint resource planning based upon a combination of WEPCO's and WPS's generating portfolios and customer bases that may create opportunities and efficiencies, if such coordination makes sense for the Companies and their customers.[38]

The system-wide implementation of resource planning which will result from the Transaction is also very supportive of environmental stewardship. Resource diversity, clean energy development, renewables integration, gas supply planning, and infrastructure (both electric and gas) modernization are all better achieved through the combined company.

In addition, by joining two electric workforces in adjacent service territories and two gas workforces in neighboring areas, the integrated system's ability to respond to major storms and other events that may disrupt service will be enhanced. WEC Energy Group's larger pool of field personnel and equipment will enable it to respond promptly and effectively to service interruptions.

Finally, the combined company will also be better able to attract and retain employees by offering them better career opportunities. This creates operational benefits as well as benefits for the workforce and the public.

Q. Will the Transaction create efficiencies and savings for customers over the long-term?

A. Yes. The combination of increased size and scope of the combined company and the operational and diversification benefits of the Transaction, also create opportunities for efficiencies and savings over the long-term. As also discussed in the testimony of Mr. Lauber, however, no meaningful net savings are expected in the near-term.

[38] No "dispatch" savings are expected because all generation will continue to be dispatched by the Midcontinent Independent System Operator ("MISO").

Q. Is it reasonable that the companies do not expect immediate savings resulting from the Transaction?

A. Yes, this is completely reasonable. Short-term savings seen in many mergers are typically the result of immediate layoffs. WEC expects that the vast majority of reductions in utility staffing will come from natural attrition over the course of time. This will minimize disruptions to the workforce and the local communities and will allow the combined company the time necessary to develop, implement and realize the benefits of a prudent integration plan. As I noted earlier in my testimony, many mergers have been consummated without the filing of a specific synergy savings analysis and with a primary focus on other drivers. This list includes:

- AltaGas Ltd. acquisition of SEMCO Holding Corporation
- AGL Resources Inc. acquisition of Nicor Inc.
- PPL Corporation acquisition of E.ON U.S. LLC
- Fortis Inc. acquisition of UNS Energy Corporation
- Integrys acquisition of Minnesota Energy Resources Corporation from Alliant Energy Corporation
- MidAmerican Energy Holdings Co. acquisition of NV Energy Inc.
- TECO Energy, Inc. acquisition of New Mexico Gas Company
- The Laclede Group, Inc. acquisition of Alabama Gas Corporation
- Macquarie Infrastructure acquisition of Duquesne Light Company
- MidAmerican Energy Holdings Co. acquisition of PacifiCorp
- AGL Resources Acquisition of NUI Corporation

Q. How might WEC Energy Group generate savings over time?

A. Merger-related savings typically accrue over time, and after upfront investment, through enhanced purchasing power, economies of scale, joint resource planning over a larger and more diverse system, the documentation, adoption and implementation of best practices, other efficiencies in operations and maintenance and project management, sharing administrative and other services over a larger organization, and the improved use of technology. Some specific areas where merger synergy savings are typically found include: insurance, shareholder services, professional services (*e.g.*, accounting, legal), credit facilities, advertising, and supply chain economies (*e.g.*, procurement, inventory, and contract services).

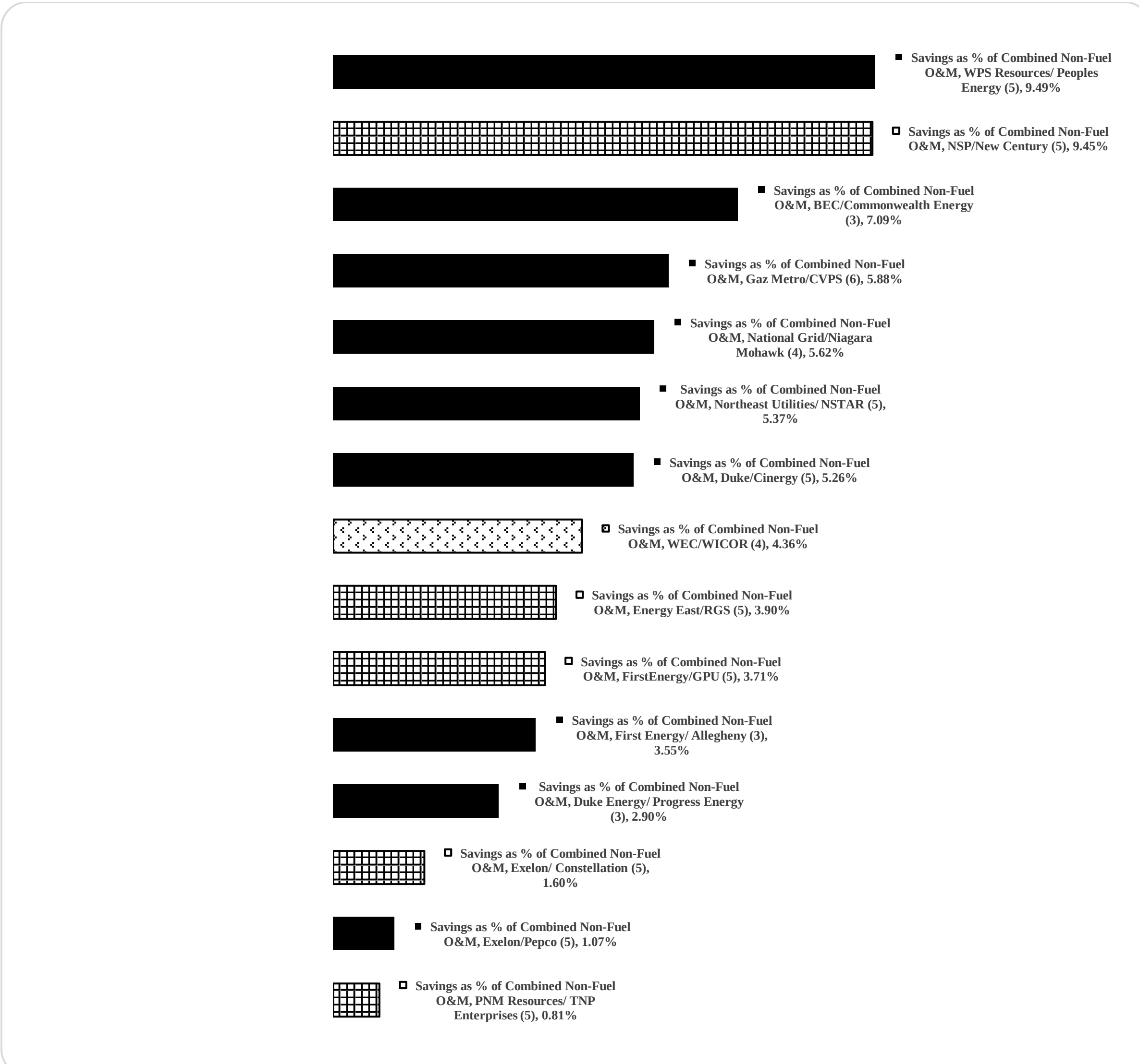
Developing and executing merger integration plans and identifying and realizing synergy savings is a detailed undertaking which takes time to accomplish, particularly in strategic mergers like the Transaction.

Q. What is your view of the merger synergy savings which might be realized from the Transaction?

A. I believe that if it is approved as proposed, the Transaction is likely to generate net savings in the range of three to five percent of non-fuel O&M of the combined company after a five to ten year ramp-up period relative to what non-fuel O&M for the Companies would have been absent the Transaction.

While neither the Companies nor I have conducted a detailed analysis of the potential merger synergy savings specific to the merger of WEC and Integrys, I have examined the synergy savings attributable to many other mergers. My view on the savings which might be realized from the Transaction is based on this examination as well as my knowledge of the Companies, their past merger integration activities, and merger synergy savings generally. Below is a chart showing the non-fuel O&M savings that were, or were expected to be, achieved in other recent mergers. These savings are net of the transition-related costs to achieve them which may include various reorganization and integration costs.

Chart 3: Survey of Historical Synergy Savings



Note: Synergy savings represent steady-state non-fuel O&M savings, net of costs to achieve. Parenthetical after each transaction signifies the assumed number of years necessary to achieve steady-state synergy savings. For mergers represented by checkerboard bars, only cumulative savings data was available and an annual savings value was estimated by taking the average annual savings over the forecast period provided. For the WEC/WICOR merger, synergy savings are actual savings as calculated after the merger was completed, and as filed with the Wisconsin PSC.

As shown in the chart above, expected net savings in non-fuel O&M in recent transactions have a central tendency in the range of 3% to 5% of combined non-fuel O&M. As I noted earlier, savings are realized after upfront investment. The mergers shown in Chart 3 were not expected to typically generate net O&M savings immediately after the merger closed, and those savings were expected to increase to a "steady state" level over a period of years.

In addition to potential non-fuel O&M savings, the Transaction can also be expected to favorably affect capital expenditures and fuel costs over the longer term. Capital expenditure savings can occur through the consolidation or avoidance of spending in areas such as IT systems and call center systems, and fuel savings have been demonstrated through joint procurement and asset management programs, which could occur here in gas pipeline and storage initiatives. On the gas side, the combined company could also be more effective in promoting the development of new pipeline infrastructure into the region and securing more economical negotiated rates for transportation services.

In considering this information, it is important to recognize that each of WEC and Integrys has been involved in other mergers which have already yielded merger savings (in the case of Integrys, recently) and WEC has made post-merger commitments that will slow the rate at which new merger synergies can be achieved.

Q. Why is it reasonable to expect that this level of savings will eventually be achievable for the WEC Energy Group?

A. Both WEC and Integrys have successfully completed integration programs after past mergers. The Transaction also has characteristics that are consistent with other recent mergers that had estimated long-term synergies in this range, including the Northeast Utilities/NSTAR merger. That merger was also not undertaken based on an expectation of large near-term merger synergies and it expected longer-term) savings of approximately 5% of non-fuel O&M costs, based on the existence of two overlapping utility services (gas and electric), adjacent service areas, and supportive regulatory environments. In my opinion, these same characteristics apply to the current Transaction.

Q. If these synergies or savings are achieved, will the benefits be seen by the customers of the operating companies?

A. Yes, they will, as these savings are achieved over the longer term. As I mentioned earlier, there are not immediate rate impacts expected from the merger. However, the shared services model of the WEC Energy Group (as reflected in the proposed affiliated interest agreements) will have the effect of eventually reducing administrative costs across the entire merged company, and each operating company's share of these net savings will be reflected in their cost of service in future rate filings. My experience with other mergers also indicates that these savings can help delay the need for future rate increases. Therefore, each operating company's customers will benefit from the merger, unlocking savings over the longer term.

Q. Has WEC provided any assurances regarding the potential for cross-subsidization within WEC Energy Group?

A. Yes. As I noted earlier in my testimony and as discussed in more detail in Mr. Lauber's testimony, WEC is seeking the Commission's approval of new affiliated interest agreements that reflect the merger and allow WEC and Integrys companies, including WBS, to provide services to one another where it is in customers' best interests to do so. Further, WEC has proposed no changes to the corporate structure of any of the combined company's individual operating utilities as a result of the Transaction. Each of the individual operating utilities will continue to maintain unique capital structures, costs of capital and financing requirements. These proposals will allow the utilities to benefit from efficiencies gained through the merger and a common service company, while continuing to reflect the cost of service for each of the individual operating utilities in customer rates.

Q. What plans does WEC have to specifically identify and pursue savings?

A. WEC plans to develop and execute specific merger integration plans over time. Merger integration plans identify the company-specific (1) opportunities to benefit from natural synergies resulting from the merger, increase efficiencies and generate specific savings, (2) costs to achieve these savings, and (3) timeframe and process for achieving the plan. The development and execution of merger integration plans is a multi-year process involving management and internal and external subject matter experts throughout the combined company. WEC is not planning any significant reductions in force or layoffs and associated near-term merger-related savings and it has not yet begun the integration process.

Q. What are the strategic benefits of the Transaction?

A. The Transaction will create a large, diversified, financially strong energy company with deep roots in Wisconsin and a commitment to the region, providing long-term strategic benefits to customers, employees, shareholders, and the communities served by WEC Energy Group's utility subsidiaries.

WEC Energy Group will be headquartered in Wisconsin. It will maintain a strong local presence in the communities it serves, including Milwaukee and Green Bay. In addition, larger and more efficient utilities should be expected to lead to lower energy costs, which can be expected to, in turn, favorably affect industrial and commercial siting decisions. Customers, employees and the local communities and State will continue to benefit from the positive impacts of these attributes on service, corporate citizenship and the local economy. WEC Energy Group will also carry on the long tradition of its predecessor companies of active involvement, philanthropic activities and charitable contributions in the communities it serves. This, coupled with the combined companies increased diversification and operational opportunities will produce significant local and regional economic benefits as compared to either continued independent operation or as part of a different merger with a different acquirer whose focus may be broader than Wisconsin and the region.

Finally, the scale, operational expertise and financial resources of WEC Energy Group will equip it to more effectively represent the interest of the states in which it operates and maintain its independence in a consolidating industry. A strong State and regional voice in national energy policy debates is a significant benefit to ensuring that these interests are both well-represented and heard. One example of such an energy policy debate is how greenhouse gas ("GHG") regulations will be implemented by the states and the federal Environmental Protection Agency ("EPA"). A stronger voice in this debate will better position Wisconsin and the region to influence rules that reflect its resource base and needs. The creation of WEC Energy Group creates incremental opportunities for the combined company and the Commission to partner in the pursuit of energy policy goals and to meet the region's future energy needs.

Q. Will the Transaction negatively impact retail competition in the region?

A. No. This merger is a purely strategic undertaking, representing the union of two companies that are almost entirely regulated utilities. The Transaction will not lessen retail competition as can occur when meaningful unregulated activities are consolidated (e.g., merchant generation, coal mining, gas production). WEC's proposal with regard to new affiliated interest agreements obviates any concern about the potential for cross-subsidization of utility and non-utility operations. Unlike some financially-oriented mergers (e.g., private equity acquisitions, international acquirers, and leveraged buy outs) there is no need for elaborate ring fencing protections.

VII. HOW THE TRANSACTION SATISFIES THE COMMISSION'S MERGER APPROVAL STANDARDS

Q. Please highlight the commission's merger approval standards.

A. As described in more detail in Section IV of my testimony, to approve a merger the Commission must review whether it is in the best interests of utility customers, investors and the public.

Q. Is the Transaction in the best interest of the Companies' Wisconsin customers?

A. Yes. The Companies' customers will enjoy the financial, diversification, operations, long-term efficiencies and strategic benefits I described in Section V of my testimony. To summarize, customers will benefit from:

- The increased scale and scope of the combined company, which will create a financially stronger company with greater liquidity and improved access to capital markets, and the ability to compete with other larger companies for capital on reasonable terms and conditions over the long-term.
- In the near-term, the strong cash flows of WEC Energy Group will allow it to fund investment in energy infrastructure out of its internally generated cash flow, including WPS' investments in environmental retrofits at the Weston 3 power

plant, underground service lines in northern Wisconsin and additional technology deployments in the State.

- The diversification which will result from bringing together the Companies' complementary geographies and service territories, customer bases, electric and gas operations, and markets will enable the combined company to better manage and balance its businesses and unlock the opportunity for increased efficiencies over time.
- The sharing of best practices across the various operating companies, the ability to optimize resources (including, for example, generation resource portfolios), the sharing of a larger experienced workforce across the system, and the ability to better attract and retain qualified personnel will create operational benefits that will be reflected in the safety, reliability and affordability of service to customers.
- While no immediate net savings are expected, merger-related efficiencies and savings are expected over time. These savings, net of the transition costs necessary to achieve them, will be reflected in customers' rates during normal rate case processes.
- WEC Energy Group will continue to have deep roots in the local communities it serves, Wisconsin and the region. Its headquarters will be in Wisconsin. It will maintain both its local presence in terms of both operations and corporate citizenship. Nearly all of any reductions in workforce from the Transaction are expected to be through natural attrition and voluntary severance.
- Finally, the scale, operational expertise and financial resources of WEC Energy group will enable it to represent the interests of Wisconsin in national energy

policy debates, maintain its independence in a consolidating industry and meet the energy needs of its customers and energy policies of the State.

These benefits are a direct result of the Transaction. I believe the Transaction is in the best interests of customers.

Q. Has WEC proposed any conditions to the Transaction to ensure these customer benefits are realized?

A. Yes. As I highlighted earlier in my testimony, WEC has proposed the following commitments, which the Commission could adopt as conditions to its approval of the Transaction. First, WEC Energy Group will not seek recovery of any acquisition premium associated with the Transaction. WEC Energy Group will also not seek recovery of any transaction costs incurred in connection with the execution of the Transaction. Second, WEC has offered certain limitations and qualifications on how WEC Energy Group will vote its new majority ownership interest in ATC to ensure that it cannot influence ATC's operations to the detriment of its other owners. Third, WEC is seeking the Commission's approval of new affiliate agreements to govern the provision of and cost allocation for services between the various operating companies, including WBS, which may, over time, provide an increasing level of services.

Q. Is the Transaction in the best interest of investors?

A. Yes. In addition to the financial benefits I note above, the Transaction provides other short and long-term benefits for both shareholders and bondholders of both WEC and Integrys. Over the near- to medium-term, the Transaction will result in higher projected earnings growth rates for the combined company, as well as an increased dividend for

WEC shareholders at closing.[39] Integrys shareholders will benefit from the Transaction through a premium above the closing price for Integrys shares prior to the announcement of the Transaction which, as I noted earlier, will not be recovered from customers. Moreover, the shareholders themselves will have the opportunity to directly express their own views of the benefits of the Transaction through the shareholder votes of the respective Companies.

In the near-term, bondholders should be unaffected by the Transaction and over the long-term they will benefit. As I noted earlier in my testimony, the Transaction has had no effect on the current credit ratings for all of the operating utility subsidiaries and Moody's views the Transaction as positive for Integrys. While the Credit Rating Agencies view the Transaction as slightly negative for WEC (the holding company) in the near-term due to the acquisition debt it will incur, their long-term view is positive due to the larger size, complementary operations and diversification which will result.

The Transaction clearly meets the Commission's investor benefit standard discussed earlier.

Q. Is the Transaction in the best interest of the public?

A. Yes. The workforce, local community, State and regional benefits I noted above clearly benefit the public. Further, I believe it is in public interest to have a strong Wisconsin-based utility holding company and operating utility subsidiaries that are locally engaged and focused on long-term financial sustainability.

Q. In your opinion does the Transaction satisfy the Commission's merger approval standards?

A. Yes, it does.

[39] See, *Wisconsin Energy to Acquire Integrys Energy Group*, June 2014, at 5, 15, and 16.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendation.

A. If approved, this Transaction will allow the formation of a Wisconsin utility holding company with the strength, breadth, operational expertise, and local and regional commitment that will create benefits for customers, investors and the public now and for the long-term. This company will act as a leader in the energy industry and will continue to constructively contribute to energy policy in Wisconsin. Importantly, these benefits will not occur without the Transaction. I recommend that the Commission approve the Transaction as proposed.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

The undersigned, Dmytro (Dmitry) Balashov, being duly sworn, deposes and says he is Senior Director, Grid Modernization for Liberty Utilities (Canada) Corp., that he has personal knowledge of the matters set forth in the foregoing Rebuttal Testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

____
Dmytro (Dmitry) Balashov, Affiant

Province of Ontario)
) ss
Regional Municipality of Halton)

Subscribed and sworn before me, a Notary Public and Commissioner for Taking Affidavits, remotely by Dmytro (Dmitry) Balashov this 17th day of March, 2022 in accordance with O. Reg 431/20, Administering Oath or Declaration Remotely.

Adam C
____
Notary Public and Commissioner for Taking Affidavits

My Commission Expires: My commission does not expire