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Study of Time-varying Wastewater Recovery Ratio Across Multiple Counties in the Eagle Ford and Marcellus Shale Plays

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Abstract—Unconventional shale gas production in the United States has been largely improved due to development of hydraulic fracturing technology. However, the acquisition of freshwater and management of flowback and produced (FP) water associated with hydraulic fracturing operation becomes one of the greatest challenges in shale gas development. Thus, it requires a better understanding of the quantity of injected water and produced FP water as well as their relationship of shale wells to help expand and upgrade the existing water network and shale gas network. We collected water-use and monthly FP water production volume data for each shale gas well available in the Eagle Ford and Marcellus shale regions from multiple database sources. Then, water recovery ratios of these wells were calculated to study their spatiotemporal variation among counties over multiple time periods. To evaluate how the water recovery ratio may affect shale gas development, a shale gas supply chain network (SGSCN) optimization model from the literature was utilized to perform two case studies in the Marcellus region. In conclusion, significantly different SGSCN configurations are required for economically desirable, and practically feasible management of wells with different water recovery ratios.

Keywords—shale gas, hydraulic fracturing, water management, water recovery ratio, supply chain network

I. INTRODUCTION

Natural gas is one of the most important energy sources used to meet global energy demand. In recent years, with constantly developing horizontal drilling and hydraulic fracturing technologies, shale gas production has been significantly improved by extracting shale gas trapped in tight formation [1]. This 'shale revolution' has triggered rapid rise of drilling of unconventional shale gas wells all over the world [2-4]. However, meanwhile it has generated intense debates on its accompanying environmental implications, regarding the amount of freshwater required for hydraulic fracturing operation and management of wastewater generated with shale gas production [2, 5-7].

The hydraulic fracturing operation for a typical shale gas well generally requires 3-7 million gallons of freshwater for its successful implementation. Further, hydraulic fracturing processes are generally completed within 2-3 days, and thus the required large amount of water must be supplied within a short time [9]. Since it can lead to a gap between local water demand and supply, particularly in water-scarce regions [5, 10-13], understanding the required water-use volume and the water availability on a local scale becomes important to plan hydraulic fracturing practices and design water supply networks. Once the hydraulic fracturing process is completed, a fraction of the injected hydraulic fracturing fluid returns to the surface due to the high natural stress in rock formation, as well as some formation water with high salinity. It is reported that the formation brine proportion in this commonly concerned flowback and produced (FP) water generally increases drastically after the first few months [12], which results in increased overall salinity and concentration of various contaminants, and thus many major environmental issues [14, 15]. Previous studies suggested that with more water being used for hydraulic fracturing operations, comparatively more FP water is being generated and thus requires expanded and upgraded wastewater management [10]. Since conventional option of deep well injection becomes less applicable due to environmental regulations [16] and handling the large amount of FP water with advanced treatment technology is generally energy-intensive and expensive [10, 17], it is necessary to develop the economically viable and environmentally sustainable wastewater management strategy directly based on the quantity and quality of produced FP water on a local scale.

In recent years, several authors have employed optimization techniques to develop various advanced water management strategies for shale gas development, such as design of water supply chain network under uncertainty [8], scheduling of hydraulic fracturing operations [15, 18], decisions of capital investments [16], and design of wastewater treatment technology [17, 19, 20]. To accomplish these studies, they required the volumes of injected water and FP water production as necessary input data. However, most of the data were collected from either a few specific wells drilled in a relatively small region or simple empirical models developed based on limited data. Since the design decisions are significantly dependent on these input data, appropriate modification of the water management strategy becomes essential to deal with spatiotemporal variability in water-use and FP water volumes [21]. In this regard, some attempts have been made to evaluate the amount of water injected for hydraulic fracturing operation and associated FP water production in major unconventional shale gas and oil regions [10, 11, 22, 23]. For the purpose of presenting water footprint of hydraulic fracturing, a metric called water intensity (i.e., the amount of water required to produce a unit volume of gas or energy) was used to normalize the data and for comparison with other energy-producing materials. However, few studies had a thorough discussion on the significance of water recovery ratio, which is defined as the ratio of the cumulative FP water volume to the corresponding water-use volume. Specifically, a greater water recovery ratio indicates that more FP water will be produced for a given amount of injected water, which implies that more water can be recycled for other hydraulic fracturing operations or reused for agricultural purposes; as a result, there will be much less stress on freshwater supply. As the wells with different water recovery ratios may require different water management strategies, obtaining preliminary knowledge about the water recovery ratio becomes critical for prediction of FP water production and thus for greener shale gas development.

Motivated by these considerations, the objective of this study is to evaluate the water recovery ratios in different shale regions and how they affect shale gas development. In this study, the water-use and FP water production volume data for the shale wells drilled in the Eagle Ford and Marcellus regions were collected from multiple databases, including the FracFocus Chemical Disclosure Registry 2.0, the DrillingInfo Desktop application and the gas and oil reporting website of the Pennsylvania Department of Environmental Protection (PA DEP). Utilizing the integrated water-use and FP water production data, we calculated the corresponding water recovery ratio for each available well, which are then analyzed spatiotemporally to present the underlying variations among different regions. Finally, a shale gas supply chain network (SGSCN) optimization model is applied to demonstrate that different optimal network configurations are required for the regions with different water recovery ratios. The spatiotemporal analysis of the water recovery ratio data will help provide a foundation for researchers and industry professionals to access, design and implement better water management practices for shale gas development.

II. Materials and Methods

A. Data Sources

The FracFocus Chemical Disclosure Registry 2.0 is used to collect water-use data for hydraulic fractured wells available in the United States. Note that in this database, well orientation of each reporting well and shale formation where the well was drilled are not reported. The DrillingInfo Desktop application provides cumulative production volumes of gas, oil and FP water for wells in the major unconventional gas and oil formation in the United States. In the case of some shale formations (e.g., the Fayetteville, Marcellus and Woodford formation), the production data are not available, and thus should be collected from other database sources. For example, the shale gas and FP water production data of the Marcellus region can be collected from the PA DEP, where the cumulative FP water production volumes are not directly posted but can be calculated by integrating the provided monthly production data.

B. Data Processing

To calculate the water recovery ratios of available shale wells, it requires integration of multiple database sources. In this study, since we mainly focused on the shale gas wells drilled in the Eagle Ford region in Texas and the Marcellus region in Pennsylvania since 2009, the water-use data were collected from the FracFocus while the cumulative FP water production data were obtained from the DrillingInfo and PA DEP. The collected water data were further filtered by primary production type (i.e., gas) and drilling type (i.e., horizontal drilling). Note that the wells with null or zero value in either water-use volume or cumulative FP water production volume were removed. Then, to match the water-use volume and the corresponding cumulative FP water production volume for each well, we used American Petroleum Institute (API) number, which is available in all the databases and can be used for well identification, to integrate the collected data. Finally, the matched water data were used to calculate the associated water recovery ratio, which is defined as the ratio of cumulative FP water volume through the entire production history to water-use volume.

Some additional information was also obtained from the databases. Specifically, geolocation information (i.e., latitude and longitude coordinate, county and state) is available in all databases, and thus, the exact location for each well can be described in the target two shale regions. In this study, we used the coordinates collected from the DrillingInfo and the PA DEP to locate the wells drilled in the Eagle Ford and Marcellus regions respectively. Besides, after the integration of database sources, temporal information of each well was also recorded, including spud date (i.e., the date when drilling commenced), hydraulic fracturing job start/end data (i.e., the date when hydraulic fracturing operation started/ended), completion date (i.e., the date when the well was completed), and first/last production date (i.e., the first/last date when the production data were reported). In this study, the first and last production dates were used to calculate the production period. Since FP water production generally lasts for many years, the cumulative FP water volume can be affected by the production period, especially for the wells which are still active. To apply the SGSCN, the corresponding shale gas production data for chosen wells were also collected from the DrillingInfo and the PA DEP databases. Note that only the gas production data were used for the subsequent analysis, even though they may also have other condensate or oil production reported.

C. Shale Gas Supply Chain Network

To evaluate how the water recovery ratio affects the configuration of SGSCN, the optimization model developed

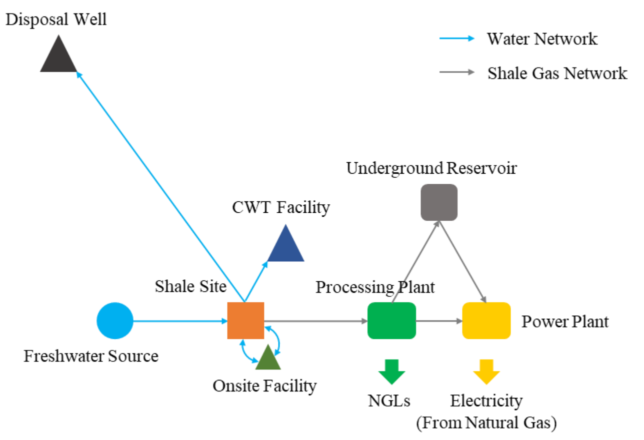


Fig. 1. Superstructure of the shale gas supply chain network

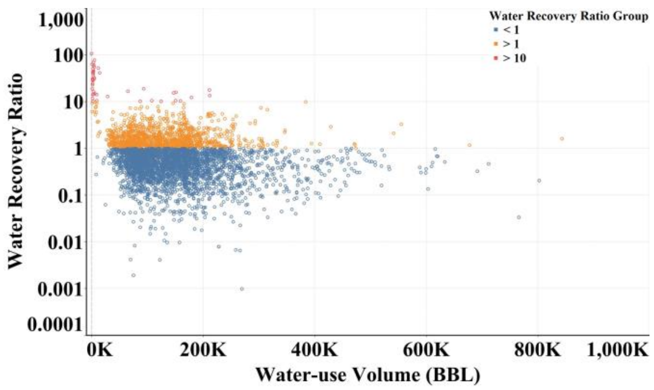
by Ahn et al. [24] was applied. The superstructure of the SGSCN is presented in Fig. 1, which can be divided into water network and shale gas network. Specifically, in the water network, the injected water required in the shale sites can be obtained from freshwater sources (i.e., freshwater) and onsite treatment facilities (i.e., recycled water). When the hydraulic fracturing job is completed, the generated FP water can be directly injected into disposal wells, or treated by centralized wastewater treatment (CWT) facilities or onsite treatment facilities. Note that the treated water from the CWT facilities is safely discharged to the surface water, while the one from the onsite treatment facilities is recycled for other hydraulic fracturing jobs. In the shale gas network, the shale gas produced from the shale sites is transported to the processing plants for separation into natural gas (i.e., methane) and natural gas liquids (NGLs; i.e., ethane, propane, etc.). Note that the NGLs are sold in the market as valuable by-products while the natural gas is eventually supplied to the power plants to generate electricity. The objective is to maximize the economic performance by optimizing the schedules of hydraulic fracturing jobs and network configuration. The necessary inputs to the SGSCN include water-use volume, FP water production and shale gas production profile for each considered shale gas well in the shale sites. In order to demonstrate the significance of different water recovery ratios to the optimal configuration of SGSCN, we considered two groups of wells in the Marcellus region, whose water recovery ratios are largely different; the design parameters associated with the SGSCN are available from the literature [24, 25].

III. RESULTS AND DISCUSSION

The data of 4,217 and 5,783 wells in the Eagle Ford region and the Marcellus region were collected, respectively. It is worthy to note that these wells are not evenly distributed in both the shale regions, and the production period of them varies from less than one year to more than ten years. For these wells, we calculated the water recovery ratios using the matched water-use and cumulative FP water production volumes, which are presented in Fig. 2. A huge difference in water recovery ratio between the Eagle Ford and Marcellus regions can be observed. Specifically, 70% of the wells in the Eagle Ford region have the water recovery ratio less than 1, while 75% of the wells in the Marcellus region have the water recovery ratio less than 0.3. Thus, the water recovery ratios of the wells in the Eagle Ford region are typically greater than the Marcellus region. Besides, the red circles in Fig. 2 indicate that there exist some outliers in both the shale regions whose water recovery ratios are even greater than 10. These outliers are attributed to either extremely small water-use volumes (Fig. 2(a) and 2(c)) or relatively large cumulative FP water volumes (Fig. 2(b) and 2(d)). Similarly, we noticed that there were also some wells with extremely low water recovery ratios whose values are less than 0.01, and the main reason is the extremely small cumulative FP water production volume (Fig. 2(b) and 2(d)), which could be due to the reporting error or short production period.

The main reason for the observed large variation in water recovery ratio within the same shale region is the difference in cumulative FP water production volume for a given water-use volume. This is because the cumulative FP water volume not only depends on the corresponding water-use volume but also the geological characteristics in the location where the well is drilled (e.g., porosity, permeability, saturation, etc.). It should be noted that the detailed information of geological characteristics is generally difficult to obtain, which makes FP water volume unpredictable and wastewater management inefficient. Thus, we used the water recovery ratio as a metric to evaluate the potential of a shale well to produce FP water, which can help differentiate regions and then provide guidance for the development of appropriate wastewater management strategies on a local scale. From this point of view, the collected water recovery ratio data were classified with respect to county. Since the water recovery ratios vary largely within each county and the data distribution is highly right-skewed, we calculated the median value of water recovery ratios in each county to represent the generalized ratio value. As presented in Fig. 3, the median water recovery ratios vary among the counties in both the shale regions, due to the difference in geological characteristics.

(a)



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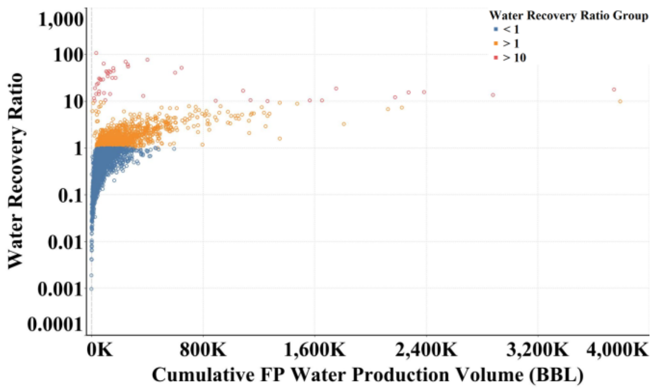

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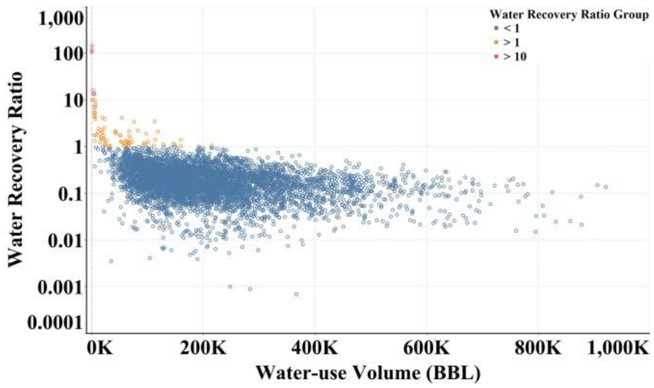

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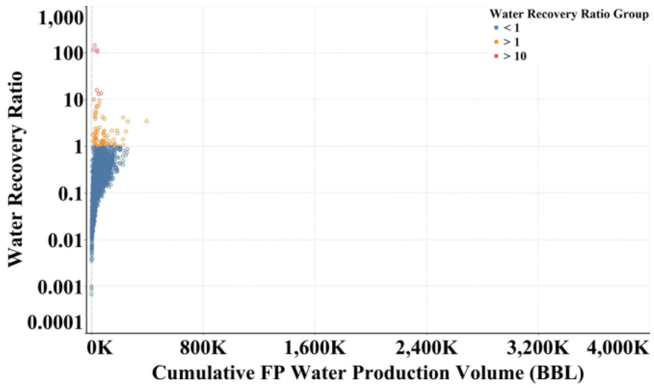
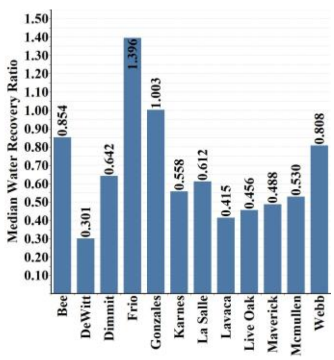


Fig. 2. Relation between the water recovery ratio and the corresponding (a) water-use volume and (b) cumulative FP water volume of the wells in the Eagle Ford region; relation between the water recovery ratio and the corresponding (c) water-use volume and (d) cumulative FP water volume of the wells in the Marcellus region

(a)



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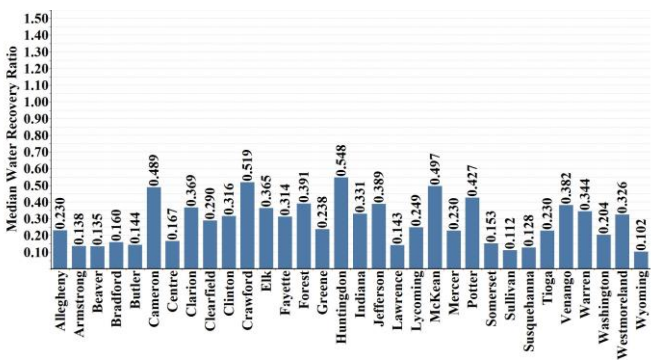
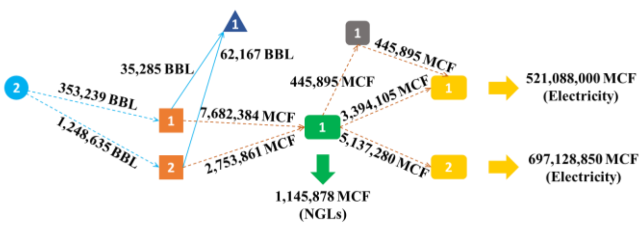


Fig. 3. Median water recovery ratio of the wells in each county in the (a) Eagle Ford region and (b) Marcellus region

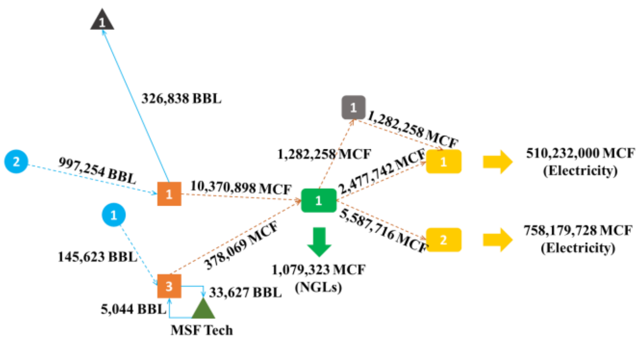
To evaluate how the different water recovery ratio may affect the SGSCN configuration, we considered two groups of shale gas wells in the Marcellus region as the inputs to the optimization model, whose water recovery ratios are around 0.1 and 0.4 for Case 1 and Case 2, respectively. While the water recovery ratios are different in the two case studies, the water-use volumes of three shale sites considered were identical (i.e., 350,000 BBL in shale site 1, 250,000 BBL in shale site 2 and 150,000 BBL in shale site 3 in both the case studies). Besides, three freshwater sources, three shale sites, three onsite treatment technologies (i.e., multistage flash (MSF), multieffect distillation (MED) and reverse osmosis (RO)), three CWT facilities, five disposal wells, two processing plants, two underground reservoirs, and two power plants are assumed to be available at the beginning in both the case studies. The planning horizon is 2 years, which is equal to the production period considered for each shale well, and is divided into eight quarters.

The overall profit of the SGSCN is determined by the trade-off between the profits (from selling the NGLs and the generated electricity) and the costs (from freshwater acquisition, wastewater management, shale gas production and processing, storage, and transportation). As presented in Fig. 4(a), to maximize the overall profit in Case 1, one well in shale site 1 and five wells in shale site 2 are drilled using the freshwater transported from freshwater source 2 by pipeline. To treat the generated FP water, only CWT facility 1 is required; to handle the produced shale gas, processing plant 1 is needed for separation of gas production while two power plants are used to generate the demanded electricity. Underground reservoir 1 is also required to storage those natural gas which cannot be transported to power plant 1 immediately. By comparison, in Case 2, only three wells in shale site 1 and one well in shale site 3 are drilled. Further, all the FP water generated in shale site 1 is injected to disposal well 1 while the FP water in shale site 3 is treated by onsite treatment facility using MSF. As a result, the difference in overall profits between the two case studies is around 1%; however, the total freshwater cost in Case 1 is 54% higher than the one in Case 2 while the associated total wastewater management cost is 59% lower.

(a)



(b)



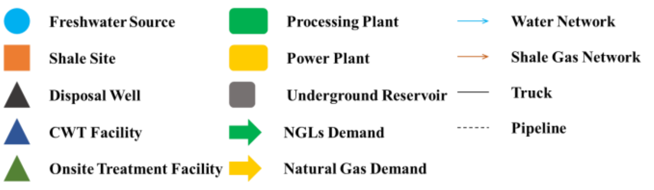


Fig. 4. Comparison of the optimal SGSCN configurations in (a) Case 1: water recovery ratio = 0.1 and (b) Case 2: water recovery ratio = 0.4

operating cost is the highest among the three available technologies, the others are not feasible here due to their low capacities. The costs associated with the freshwater acquisition and wastewater management in both the case studies are presented in Fig. 5. Unlike the FP water production, the total amount of shale gas production in Case 1 (i.e., 10,436,245 mcf) is close to the one in Case 2 (i.e., 10,748,967 mcf). Note that the resulting total shale gas production cost in Case 1 is around 10% higher than the one in Case 2 since it also contains drilling cost which is

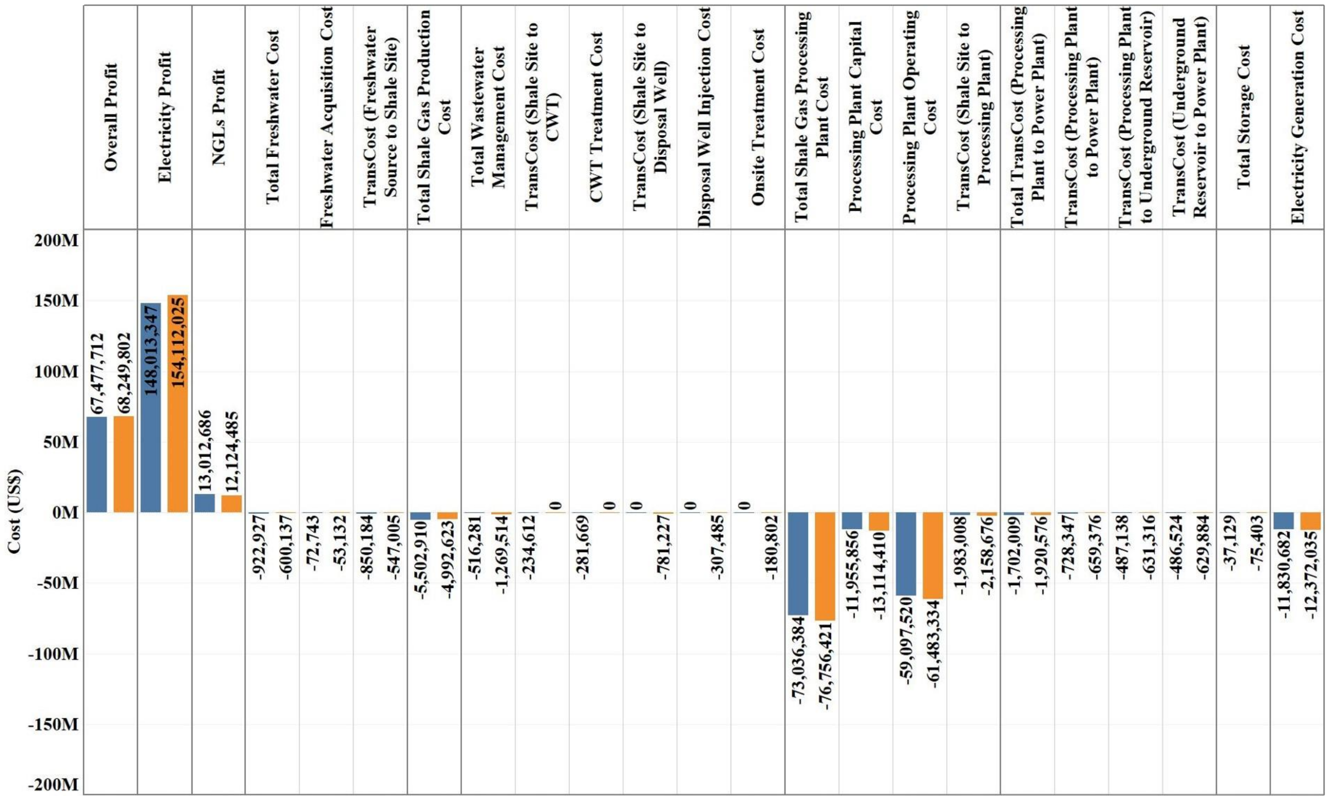


Fig. 5. Comparison of the detailed costs in the two case studies (Case 1 is represented by blue; Case 2 is represented by orange)

Specifically, based on the optimal schedules of hydraulic fracturing jobs in the two case studies, the resulting total amount of freshwater in Case 1 (i.e., 1,601,874 BBL) is much larger than the one in Case 2 (i.e., 1,147,921 BBL). To obtain the large amount of freshwater, freshwater source 2 is generally used due to its larger capacity than freshwater source 1 and the shorter distances to shale sites than freshwater source 3. Note that since the maximum capacity of a truck is only 135,000 BBL, pipeline is always the only feasible transportation mode in both the case studies. On the other hand, due to the greater water recovery ratio in Case 2, the total amount of generated FP water (i.e., 360,465 BBL) is even much larger than the one (i.e., 97,452 BBL) in Case 1. Thus, compared to using nearby CWT facility as Case 1, it is more economically preferred to inject the large amount of FP water produced in Case 2 to disposal well 1 due to the extremely low injection cost, regardless of the long distances between shale sites and disposal wells. As for shale site 3, since there is only one well which is drilled at the end of the planning horizon, the onsite facility is chosen mainly to avoid the high transportation cost. Even though the recovery factor (i.e., the ratio of recycled water volume to FP water volume) of the applied MSF is the lowest and its unit

dependent on the number of drilled wells. Since a large proportion of the shale gas production in Case 2 is generated in shale site 1 where the composition of NGLs is the smallest among the three shale sites considered, the resulting total amount of separated NGLs is observed to be relatively less than those in Case 1 while the total amount of natural gas is relatively more. Thus, the associated profit from selling the NGLs in Case 2 is lower than the one in Case 1; however, the profit from selling the electricity as well as the cost of electricity generation in Case 2 is higher than Case 1.

As shown in Fig. 5, the economic performance of the water network is almost negligible in comparison to the shale gas network in both the case studies. To maximize the overall profit, the SGSCN configurations in both the case studies are designed to make the amounts of NGLs sold and natural gas transported for electricity generation as close to the maximum demands as possible through the entire planning horizon. Thus, it is the maximum product demand as well as shale gas production profile that mainly determines the sequence and timing of hydraulic fracturing jobs, and the shale gas network configuration. However, the associated total amount of FP water production can be significantly different due to different water recovery ratio, which may require different optimal water network configuration and lead to different economic performance.

The two case studies suggest that with a given injected water volume, when the water recovery ratio is low, the amount of FP water production is small and thus CWT is generally economically and environmentally preferred; however, when the water recovery ratio is high, the amount of FP water production is large and thus disposal well is generally the first choice. Note that, for onsite treatment facility, even though it does not require any transportation cost and can save some freshwater cost by recycling the treated water for other hydraulic fracturing jobs, it is still generally the last choice due to its much higher unit operating cost than those of CWT and disposal well. Thus, even though the objectives are the same (i.e., maximize overall economic performance), the designs and configurations of SGSCN can be significantly different in the regions with different water recovery ratios, especially the optimal water network configuration.

V. CONCLUSIONS

In this study, we focused on analyzing the water recovery ratios of the shale gas wells drilled in the Eagle Ford and Marcellus shale regions, by utilizing the integrated water-use and FP water volume data collected from multiple databases. Specifically, in the Eagle Ford region, around 30% of the wells had the water recovery ratio greater than 1; however, in the Marcellus region, only around 1.5% of the wells had the water recovery ratio greater than 1 while around 75% of the wells had the ratio less than 0.3. Further, the water recovery ratios also varied largely among and even within the counties in each shale region. The objective of this study was to use the water recovery ratio as a metric to evaluate regional differences and how it may affect water and shale gas supply chain networks. According to the two case studies, when the water recovery ratio was low, the FP water was transported to nearby CWT facilities for preliminary treatment before being safely discharged to surface water; on the other hand, when the water recovery ratio was high, it was economically preferred to directly inject the FP water to disposal wells or treat them using advanced technologies for the purpose of recycle. Thus, the water recovery ratio decisively determines which water management strategy is the most profitable, and thus, different SGSCN configurations should be considered in different regions.

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