water quality and public health, with the U.S. Department of Energy having only recently released a report on August 11, 2011, recommending the implementation of a variety of measures to reduce the environmental impacts from shale-gas production. Similarly, the U.S. Congress and several states, including New York and Pennsylvania, have proposed or enacted legislation or regulations that are expected to make it more difficult or costly for exploration and production companies to produce natural gas and NGLs. These initiatives, enactments and regulations could have an indirect adverse impact on us by decreasing demand for the storage and transportation services that we offer.

**Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating and capital costs and reduced demand for our storage services.**

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011, which could require greenhouse emission controls for those sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that is produced, which may decrease demand for our storage services. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

**The credit and risk profile of our general partner and its owner, NRGY, could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.**

The credit and business risk profiles of our general partner and NRGY may be factors considered in credit evaluations of us. This is because our general partner, which is owned by NRGY, controls our business activities, including our cash distribution policy and growth strategy. Any adverse change in the financial condition of NRGY, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness, may adversely affect our credit ratings and risk profile.
If we were to seek a credit rating in the future, our credit rating may be adversely affected by the leverage of our general partner or NRGY, as credit rating agencies such as Standard & Poor’s Ratings Services and Moody’s Investors Service may consider the leverage and credit profile of NRGY and its affiliates because of their ownership interest in and control of us. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make distributions to common unitholders.

Increases in interest rates could adversely impact demand for our storage capacity, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash distributions at our intended levels.

There is a financing cost for our customers to store natural gas or NGLs in our storage facilities. That financing cost is impacted by the cost of capital or interest rate incurred by the customer in addition to the commodity cost of the natural gas or NGLs in inventory. Absent other factors, a higher financing cost adversely impacts the economics of storing natural gas or NGLs for future sale. As a result, a significant increase in interest rates could adversely affect the demand for our storage capacity independent of other market factors.

In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our common unit price is impacted by the level of our cash distributions and our implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our common unit price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash distributions at our intended levels.

If we are unable to diversify our assets and geographic locations, our ability to make distributions to our common unitholders could be adversely affected.

We rely exclusively on revenues generated from storage and transportation assets that we own, which are exclusively located in the Northeast region of the United States. Due to our lack of diversification in asset location and the storage-heavy nature of our existing asset base, an adverse development in these businesses or areas, including adverse developments due to catastrophic events, weather and decreases in demand for natural gas, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

Prior to this offering, we have not been required to file reports with the SEC. Upon the completion of this offering, we will become subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 for our fiscal year ending September 30, 2013. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations.
obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm’s, conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

**Terrorist attacks aimed at our facilities or surrounding areas could adversely affect our business.**

The U.S. government has issued warnings that energy assets, specifically the nation’s pipeline and terminal infrastructure, may be the future targets of terrorist organizations. Any terrorist attack at our facilities, those of our customers and, in some cases, those of other pipelines, refineries or terminals could materially and adversely affect our business, financial condition, results of operations or cash flows.

**Risks Inherent in an Investment in Us**

*NRGY owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including NRGY, have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of us and our common unitholders.*

Following this offering, NRGY will own and control our general partner and will appoint all of the directors of our general partner. Although our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our common unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to NRGY. Therefore, conflicts of interest may arise between our general partner and its affiliates, including NRGY, on the one hand, and us and our common unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires NRGY to pursue a business strategy that favors us, and directors and officers of NRGY’s general partner have a fiduciary duty to make these decisions in the best interests of the owners of NRGY, which may be contrary to our interests;
- NRGY is under no obligation to make acquisition opportunities available to us and may compete with us;
- certain of our officers may devote the majority of their time to our business, while other officers will have responsibilities for both us and NRGY and will devote less than a majority of their time to our business;
- our general partner and its affiliates are allowed to take into account the interests of parties other than us in resolving conflicts of interest;
- our partnership agreement limits the liability of and reduces fiduciary duties owed by our general partner and also restricts the remedies available to our common unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without common unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our common unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
Our general partner intends to limit its liability regarding our contractual and other obligations.

Our general partner intends to limit its liability under our contractual and other obligations so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner’s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our common unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our common unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.
In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There will be no limitations in our partnership agreement, and we do not expect to have limitations in our revolving credit facility, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our common unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our common unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to any units it owns;
- whether to exercise its registration rights;
- whether to elect to reset the initial quarterly distribution; and
- whether or not to consent to any merger or consolidation of us or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above. Please read "Conflicts of Interest and Fiduciary Duties—Fiduciary Duties."

Our partnership agreement limits the liability of and reduces fiduciary duties owed by our general partner and also restricts the remedies available to our common unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to our common unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it believed that the decision was in the best interests of our partnership, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our common unitholders for decisions made in its capacity as a general partner so long as it acted in good faith; and
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.
NRGY and other affiliates of our general partner may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Affiliates of our general partner, including NRGY, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. NRGY currently holds interests in, and may make investments in and purchases of, entities that acquire, own and operate natural gas and NGL storage and transportation businesses. These investments and acquisitions may include entities or assets that we would have been interested in acquiring. Therefore, NRGY may compete with us for investment opportunities, and NRGY may own an interest in entities that compete with us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and NRGY. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders. Please read “Conflicts of Interest and Fiduciary Duties.”

We will not have any subordinated units outstanding and NRGY is entitled to receive 50% of all cash that we distribute in excess of the initial quarterly distribution of $ per common unit.

Unlike most publicly traded partnerships with incentive distribution rights, we will not have any subordinated units held by our general partner and its affiliates the distributions on which would be reduced in order to support a distribution to common unitholders. Because there will not be a security junior to the common units to absorb a shortfall in the distribution from the initial quarterly distribution, the common units will bear any and all shortfalls in the amount of cash needed to pay the initial quarterly distribution on all units. Similarly, the common units will not be entitled to arrearages in the event the initial quarterly distribution is not paid in a quarter. Furthermore, unlike many publicly traded partnerships with incentive distribution rights that only increase to 50% after moving through several increasing target distributions above a minimum quarterly distribution, NRGY is entitled to receive 50% of all cash that we distribute in excess of the initial quarterly distribution per common unit, including cash generated from our existing internal growth projects. As a result of our incentive distribution structure, we may have a higher equity cost of capital than many other publicly traded partnerships, which may make it more difficult for us to compete for acquisitions or to consummate acquisitions or internal growth projects that result in meaningful accretion to our common unitholders.

NRGY may elect to cause us to issue common units to it in connection with a resetting of the initial quarterly distribution related to its incentive distribution rights, without the approval of the conflicts committee of the board of directors of our general partner or the holders of our common units. This election could result in lower distributions to our common unitholders.

NRGY has the right to reset, at a higher level, the initial quarterly distribution based on our cash distributions at the time of the exercise of the reset election. Following a reset election by NRGY, the initial quarterly distribution will be reset to an amount equal to the cash distribution amount per unit for the quarter immediately preceding the reset election (which amount we refer to as the “reset initial quarterly distribution”).

If NRGY elects to reset the initial quarterly distribution, it will be entitled to receive a number of newly issued common units. The number of common units to be issued to NRGY will equal the number of common units that would have entitled the holder to the quarterly cash distribution in the prior quarter equal to the distribution to NRGY on the incentive distribution rights in such prior quarter. It is possible that NRGY could
exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial quarterly distribution. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to NRGY in connection with resetting the initial quarterly distribution. Please read “Provisions of Our Partnership Agreement Relating to Cash Distributions—NRGY’s Right to Reset Incentive Distribution Level.”

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, our common unitholders will have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our common unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by NRGY, as a result of it owning our general partner, and not by our common unitholders. Please read “Management—Management of Inergy Midstream, L.P.” and “Certain Relationships and Related Party Transactions.” Unlike publicly traded corporations, we will not conduct annual meetings of our common unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

If our common unitholders are dissatisfied with the performance of our general partner, they will have limited ability to remove our general partner. Common unitholders initially will be unable to remove our general partner without its consent because NRGY will own sufficient units upon the completion of this offering to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all our outstanding common units is required to remove our general partner. Following the closing of this offering, NRGY will own, directly or indirectly, an aggregate of % of our common units (or % of our common units, if the underwriters exercise their option to purchase additional common units in full).

Common unitholders will experience immediate and substantial dilution in net tangible book value per common unit of $ per common unit.

The assumed initial public offering price of $ per common unit (the midpoint of the price range set forth on the cover page of this prospectus) exceeds pro forma net tangible book value of $ per common unit. Based on the assumed initial public offering price of $ per common unit, common unitholders will incur immediate and substantial dilution in net tangible book value per common unit of $ per common unit. This dilution results primarily because our assets are recorded at their historical cost in accordance with GAAP, and not their fair value. Please read “Dilution.”

Our general partner interest and our incentive distribution rights may be transferred without common unitholder consent.

Our partnership agreement provides that our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our common unitholders, and our common unitholders will have no right to elect our general partner or its directors on an annual or other continuing basis. In addition, in connection with this offering, NRGY and Holdings GP, the indirect owner of NRGY’s general partner, expect to enter into an agreement under which Holdings GP will be required to purchase our general partner in the event that (i) of a change of control of NRGY occurs or (ii) NRGY is entitled to receive less than 25% of all cash distributed with respect to our limited partner interests and incentive distribution rights. Please read “Security Ownership of Certain Beneficial Owners and
Management.” As a result, subject to receiving Holding GP’s consent, the member of our general partner may transfer its membership interest in our general partner to a third party. The new member of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with its designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a “change of control” without the vote or consent of the common unitholders.

Our partnership agreement also provides that the holder of the incentive distribution rights may transfer those interests to a third party at any time without the consent of our common unitholders. NRGY indirectly owns all of our incentive distribution rights. If NRGY transfers its incentive distribution rights to a third party, NRGY may not have the same incentive to grow our partnership and increase quarterly distributions to common unitholders over time as it would if it had retained ownership of the incentive distribution rights.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than % of the outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests and (2) the average of the daily closing prices of the partnership securities of such class over the 20 consecutive trading days immediately preceding the date three days before the date the notice is mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act. Upon completion of this offering, and assuming no exercise of the underwriters’ option to purchase additional common units, NRGY will own, directly or indirectly, an aggregate of % of our common units. For additional information about the limited call right, please read “The Partnership Agreement—Limited Call Right.”

We may issue additional units without common unitholder approval, which would dilute existing common unitholder ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests we may issue at any time without the approval of our common unitholders. The issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- our existing common unitholders’ proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of the common units may decline. Please read “The Partnership Agreement—Issuance of Additional Interests.”

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The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by NRGY or other large common unitholders.

Upon completion of this offering, we will have common units outstanding, which includes the common units we are selling in this offering that may be resold in the public market immediately (if the underwriters exercise in full their option to purchase additional common units). All of the common units (if the underwriters exercise in full their option to purchase additional common units) that are issued to NRGY will be subject to resale restrictions under a 180-day lock-up agreement with the underwriters. Each of the lock-up agreements with the underwriters may be waived in the discretion of certain of the underwriters. Sales of a substantial number of our common units by NRGY or other large common unitholders in the public markets following this offering, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. In addition, we have agreed to provide registration rights to NRGY. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold, subject to certain limitations. Please read “Units Eligible for Future Sale.”

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders’ voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Neither our partnership agreement nor the omnibus agreement will limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our common unitholders. Please read “Cash Distribution Policy and Restrictions on Distributions.”

The amount of cash we have available for distribution to common unitholders depends primarily on our cash flow and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may pay cash distributions during periods when we record net losses for financial accounting purposes and may not pay cash distributions during periods when we record net income.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and common unitholders could lose all or part of their investment.

Prior to this offering, there has been no public market for the common units. Upon completion of this offering, there will be only publicly traded common units held by our public unitholders (common units if the underwriters exercise their option to purchase additional common units in full). We do not know the extent
The initial public offering price for our common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- the other factors described in these “Risk Factors.”

Common unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, or the Delaware Act, we may not make a distribution to our common unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

It may be determined that the right, or the exercise of the right by the limited partners as a group, to (i) remove or replace our general partner, (ii) approve some amendments to our partnership agreement or (iii) take other action under our partnership agreement constitutes “participation in the control” of our business. A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. Please read “The Partnership Agreement—Limited Liability.”

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The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We intend to apply to list our common units on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner’s board of directors or establish a compensation committee or a nominating and corporate governance committee. Accordingly, common unitholders will not have the same protections afforded to most corporations that are subject to all of the NYSE corporate governance requirements. Please read “Management—Management of Inergy Midstream, L.P.”

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses that we did not incur prior to this offering. In addition, the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. Before we are able to make distributions to our common unitholders, we must first pay or reserve cash for our expenses, including the costs of being a publicly traded partnership. As a result, the amount of cash we have available for distribution to our common unitholders will be affected by the costs associated with being a publicly traded partnership.

Prior to this offering, we have not filed reports with the SEC. Following this offering, we will become subject to the public reporting requirements of the Exchange Act. We expect these rules and regulations to increase certain of our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our SEC reporting requirements.

We estimate that we will incur approximately $3.0 million of incremental external costs per year and additional internal costs associated with being a publicly traded partnership; however, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, please read “Material U.S. Federal Income Tax Consequences” for a more complete discussion of the expected material U.S. federal income tax consequences of owning and disposing of common units.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.
If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the common unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the initial quarterly distribution may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We are unable to predict whether any of these changes, or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our common unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Immediately following this offering, NRGY will own, directly and indirectly, more than 50% of the total interests in our capital and profits interests. Therefore, a transfer by NRGY (including a deemed transfer as a result of a termination of NRGY) of all or a portion of its interests in us could result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all common unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Units—Constructive Termination” for a discussion of the consequences of our termination for federal income tax purposes.
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Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a common unitholder’s share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Units—Recognition of Gain or Loss” for a further discussion of the foregoing.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts, or IRAs, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Our costs of any contest with the IRS will be borne indirectly by our common unitholders because the costs will reduce our cash available for distribution.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Due to a number of factors, including our inability to match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read “Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership—Section 754 Election” for a further discussion of the effect of the depreciation and amortization positions we adopt.
We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our common unitholders.

We will generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our common unitholders. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Units—Allocations Between Transferors and Transferees” for further discussion of the methods that we use for allocations between transferors and transferees.

A unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there is no tax concept of loaning a partnership interest, a unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of the loaned units. In that case, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Common unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We will initially own assets and conduct business in the states of New York and Pennsylvania. Each of these states currently imposes a personal income tax and also imposes income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.
USE OF PROCEEDS

We intend to use the estimated net proceeds of approximately $ million from this offering, after deducting the estimated underwriting discounts and commissions, the structuring fee and offering expenses payable by us, to repay approximately $ million of indebtedness outstanding under our revolving credit facility.

The borrowings under our revolving credit facility that we will assume from NRGY in connection with our formation transactions were primarily incurred to fund acquisitions and growth projects at NRGY. Borrowings under our revolving credit facility bear interest at approximately %. We expect our revolving credit facility will mature on , 2016.

We expect to re-borrow $80 million under our revolving credit facility to fund a cash distribution to NRGY for reimbursement of capital expenditures associated with our assets.

If and to the extent the underwriters exercise their option to purchase all or a portion of the additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public and the remainder of the additional common units, if any, will be issued to NRGY. Any such units issued to NRGY will be issued for no additional consideration. If the underwriters exercise their option to purchase additional common units in full, the additional net proceeds would be approximately $ million. The net proceeds from any exercise of such option will be distributed to NRGY. If the underwriters do not exercise their option to purchase additional common units, we will issue common units to NRGY upon the option’s expiration. We will not receive any additional consideration from NRGY in connection with such issuance. Accordingly, the exercise of the underwriters’ option will not affect the total number of common units outstanding or the amount of cash needed to pay the initial quarterly distribution on all common units. Please read “Underwriting.”

A $1.00 increase or decrease in the assumed initial public offering price of $ per common unit would cause the net proceeds from this offering, after deducting the estimated underwriting discounts and commissions, the structuring fee and offering expenses payable by us, to increase or decrease, respectively, by approximately $ million. In addition, we may also increase or decrease the number of common units we are offering. Each increase of 1.0 million common units offered by us, together with a concurrent $1.00 increase in the assumed public offering price to $ per common unit, would increase net proceeds to us from this offering by approximately $ million. Similarly, each decrease of 1.0 million common units offered by us, together with a concurrent $1.00 decrease in the assumed initial offering price to $ per common unit, would decrease the net proceeds to us from this offering by approximately $ million.

Affiliates of certain of the underwriters are lenders under our revolving credit facility and, accordingly, will receive a substantial portion of the proceeds from this offering. Please read “Underwriting.”
The following table shows our cash and cash equivalents and capitalization as of June 30, 2011:

- on an actual basis; and
- as adjusted to reflect this offering of our common units, the other transactions described under “Summary—Formation Transactions and Partnership Structure” and the application of the net proceeds from this offering as described under “Use of Proceeds.”

This table is derived from, and should be read together with, the unaudited pro forma condensed consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with “Summary—Formation Transactions and Partnership Structure,” “Use of Proceeds” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

<table>
<thead>
<tr>
<th></th>
<th>Actual</th>
<th>As Adjusted</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and cash equivalents</td>
<td>$ 9.4</td>
<td></td>
</tr>
<tr>
<td>Debt:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revolving credit facility</td>
<td>$ —</td>
<td>$ 80.0(^{(a)})</td>
</tr>
<tr>
<td>Member’s/partners’ capital:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Held by public:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Common units</td>
<td>—</td>
<td></td>
</tr>
<tr>
<td>Held by NRGY:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net parent capital</td>
<td>475.9</td>
<td></td>
</tr>
<tr>
<td>Common units</td>
<td>—</td>
<td></td>
</tr>
<tr>
<td>General partner interest</td>
<td>—</td>
<td></td>
</tr>
<tr>
<td>Total member’s/partners’ capital</td>
<td>$475.9</td>
<td>$</td>
</tr>
<tr>
<td>Total capitalization</td>
<td>$475.9</td>
<td>$</td>
</tr>
</tbody>
</table>

\(^{(a)}\) Reflects (i) our assumption of approximately $\text{\textdollar}{80.0} million of indebtedness from NRGY under our revolving credit facility that will be assigned to us of which we will repay $\text{\textdollar}{80.0} million using the net proceeds of this offering and (ii) our re-borrowing of approximately $\text{\textdollar}{80.0} million under our revolving credit facility, which will be used to reimburse NRGY for capital expenditures incurred prior to this offering related to our assets.
DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the net tangible book value per common unit after the offering. Assuming an initial public offering price of $ per common unit (the midpoint of the price range set forth on the cover page of this prospectus), on a pro forma basis as of June 30, 2011, after giving effect to the offering of common units and the related transactions, our net tangible book value was approximately $ million, or $ per common unit. Purchasers of our common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table.

<table>
<thead>
<tr>
<th>Assumed initial public offering price per common unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pro forma net tangible book value per common unit before the offering (1)</td>
</tr>
<tr>
<td>Increase in net tangible book value per common unit attributable to purchasers in the offering</td>
</tr>
<tr>
<td>Less: Pro forma net tangible book value per common unit after the offering (2)</td>
</tr>
<tr>
<td>Immediate dilution in net tangible book value per common unit to purchasers in the offering (3)(4)</td>
</tr>
</tbody>
</table>

(1) Determined by dividing the pro forma net tangible book value of our assets and liabilities by the number of common units (common units, assuming no exercise of the underwriters’ option to purchase additional common units) to be issued to our affiliates.

(2) Determined by dividing our pro forma net tangible book value, after giving effect to the use of the net proceeds of the offering, by the total number of common units (common units, assuming no exercise of the underwriters’ option to purchase additional common units) to be outstanding after the offering.

(3) Each $1.00 increase or decrease in the assumed public offering price of $ per common unit would increase or decrease, respectively, our pro forma net tangible book value by approximately $ million, or approximately $ per common unit, and dilution per common unit to investors in this offering by approximately $ per common unit, after deducting the estimated underwriting discounts and commissions, the structuring fee and offering expenses payable by us. We may also increase or decrease the number of common units we are offering. An increase of 1.0 million common units offered by us, together with a concurrent $1.00 increase in the assumed offering price to $ per common unit, would result in a pro forma net tangible book value of approximately $ million, or $ per common unit, and dilution per common unit to investors in this offering would be $ per common unit. Similarly, a decrease of 1.0 million common units offered by us, together with a concurrent $1.00 decrease in the assumed public offering price to $ per common unit, would result in an pro forma net tangible book value of approximately $ million, or $ per common unit, and dilution per common unit to investors in this offering would be $ per common unit. The information discussed above is illustrative only and will be adjusted based on the actual public offering price and other terms of this offering determined at pricing.

(4) Because the total number of units outstanding following this offering will not be impacted by any exercise of the underwriters’ option to purchase additional common units and any net proceeds from such exercise will not be retained by us, there will be no change to the dilution in net tangible book value per common unit to purchasers in the offering due to any such exercise of the option.

The following table sets forth the number of common units that we will issue and the total consideration contributed to us by NRGY and by the purchasers of our common units in this offering upon completion of the transactions contemplated by this prospectus.

<table>
<thead>
<tr>
<th>Common Units</th>
<th>Total Consideration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number</td>
<td>Percent</td>
</tr>
<tr>
<td>NRGY (1)(2)</td>
<td>%</td>
</tr>
<tr>
<td>Purchasers in the offering (2)</td>
<td>%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
</tr>
</tbody>
</table>

(1) Upon the completion of the transactions contemplated by this prospectus, NRGY will own common units, assuming no exercise of the underwriters’ option to purchase additional common units.

(2) A $1.00 increase (decrease) in the assumed initial public offering price of $ per common unit would increase (decrease) total consideration paid by purchasers in this offering by $ million, and total consideration provided by NRGY by $
million, in each case assuming the number of common units offered hereby, as set forth on the cover page of this prospectus, remains the same.
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CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with "—Assumptions and Considerations" below, which includes the factors and assumptions upon which we base our cash distribution policy. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

For additional information regarding our historical and pro forma results of operations, you should refer to our audited historical consolidated financial statements as of September 30, 2009 and 2010 and for the fiscal years ended September 30, 2008, 2009 and 2010, our unaudited historical consolidated financial statements as of June 30, 2011 and for the nine months ended June 30, 2010 and 2011 and our unaudited pro forma condensed consolidated financial statements for the fiscal year ended September 30, 2010 and as of and for the nine months ended June 30, 2011 included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a judgment that our common unitholders will be better served by our distributing rather than retaining our available cash. Our partnership agreement generally defines available cash as, for each quarter, (i) all cash on hand at the end of that quarter, less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, comply with applicable law, any of our debt agreements or other agreement or provide funds for distributions to our common unitholders for any one or more of the next four quarters, plus (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute to our common unitholders than would be the case were we subject to entity-level federal income tax.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will distribute quarterly cash distributions to our common unitholders. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including:

- We expect that our cash distribution policy will be subject to restrictions on distributions under our revolving credit facility, and other debt agreements that we enter into in the future may have similar restrictions. Specifically, the agreement governing our revolving credit facility is expected to contain financial covenants that we must satisfy. Should we be unable to satisfy these restrictions or if we are otherwise in default under our revolving credit facility, we would be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.

- Our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our common unitholders, and the establishment of or increase of those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner in good faith will be binding on our common unitholders.

- Although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by NRGY). At the closing of this offering, NRGY will own, directly or indirectly, approximately % of the outstanding common units. Please read “The Partnership Agreement—Amendment of the Partnership Agreement.”
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- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our common unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating and administrative expenses (including the reimbursement to our general partner and its affiliates under the omnibus agreement for all direct and indirect expenses they incur on our behalf), principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to common unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase. Please read “Provisions of Our Partnership Agreement Relating to Cash Distributions—Distributions of Available Cash.”

- Our ability to make distributions to our common unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

- If we make distributions out of capital surplus, as opposed to operating surplus, any such distributions would constitute a return of capital and would result in a reduction in the initial quarterly distribution. Please read “Provisions of Our Partnership Agreement Relating to Cash Distributions—Adjustment to the Initial Quarterly Distribution.” We do not anticipate that we will make any distributions from capital surplus.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital

Our partnership agreement requires us to distribute all of our available cash to our common unitholders on a quarterly basis. As a result, we expect that we will rely primarily upon external financing sources, including borrowings under our revolving credit facility and issuances of debt and equity securities, to fund expansion capital expenditures. Our cash distribution policy may significantly impair our ability to grow if we are unable to access these external sources to finance our growth. In addition, because we distribute all of our available cash, our growth may not be as fast as businesses that reinvest all of their available cash to expand ongoing operations. To the extent we issue additional units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our common unitholders.

Our Initial Quarterly Distribution

Upon the completion of this offering, the board of directors of our general partner will establish an initial quarterly distribution of $ per unit for each complete quarter, or $ per year, to be paid within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2011. This equates to an aggregate cash distribution of $ million per quarter, or $ million per year, based on the number of common units that will be outstanding immediately after completion of this offering. Our ability to make cash distributions at the initial quarterly distribution rate will be subject to the restrictions described above under “—General—Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy.”
If the underwriters do not exercise their option to purchase additional common units, we will issue common units to NRGY at the expiration of the option period. If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be sold to the public and any units not purchased by the underwriters pursuant to their option will be issued to NRGY as part of our formation transactions. Accordingly, the exercise of the underwriters’ option will not affect the total number of units outstanding or the amount of cash needed to pay the initial quarterly distribution on all common units. Please read “Underwriting.”

The table below sets forth the amount of common units that will be outstanding immediately after the closing of this offering and the available cash needed to pay the aggregate initial quarterly distribution on all of such units for a single fiscal quarter and a four quarter period:

<table>
<thead>
<tr>
<th>Publicly held common units</th>
<th>Number of Units</th>
<th>Distributions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>One Quarter</td>
<td>Annualized</td>
</tr>
<tr>
<td></td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Common units held by NRGY</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>General partner interest</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>(1) Total</td>
<td>$</td>
<td>$</td>
</tr>
</tbody>
</table>

(1) Our general partner owns a non-economic general partner interest.

As of the date of this offering, NRGY will hold the incentive distribution rights, which entitle the holder to 50.0% of the cash we distribute in excess of $ per unit per quarter.

We do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate, except as provided in our partnership agreement. Our cash distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly. Although holders of our common units may pursue judicial action to enforce provisions of our partnership agreement, including those related to requirements to make cash distributions as described above, our partnership agreement provides that any determination made by our general partner in its capacity as our general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by the Delaware Act or any other law, rule or regulation or at equity. Our partnership agreement provides that, in order for a determination by our general partner to be made in “good faith,” our general partner must believe that the determination is in our best interest. Please read “Conflicts of Interest and Fiduciary Duties.”

The actual amount of our cash distributions for any quarter is subject to fluctuations based on, among other things, the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement. We will pay our distributions no later than 45 days following the end of each quarter to common unitholders of record on the record date selected by our general partner in its reasonable discretion. We will adjust the first quarterly distribution following this offering on a pro rata basis for the period from the closing date of this offering through December 31, 2011 based on the actual length of the period.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our initial quarterly distribution of $ per quarter for the twelve months ending December 31, 2012. In those sections, we present two tables, consisting of:

- “Unaudited Pro Forma Cash Available for Distribution,” in which we present the amount of cash we would have had available for distribution on a pro forma basis for our fiscal year ended September 30, 2010 and the twelve months ended June 30, 2011, derived from our unaudited pro forma financial data that are included in this prospectus, as adjusted to give pro forma effect to the offering and the formation transactions; and
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- “Estimated Cash Available for Distribution for the Twelve Months Ending December 31, 2012,” in which we demonstrate our ability to generate the estimated Adjusted EBITDA necessary for us to pay the initial quarterly distribution on all units for each quarter for the twelve months ending December 31, 2012.

Unaudited Pro Forma Cash Available for Distribution

If we had completed the transactions contemplated in this prospectus on October 1, 2009, our unaudited pro forma cash available for distribution for the twelve months ended September 30, 2010, would have been approximately $65.8 million. If we had completed the transactions contemplated in this prospectus on July 1, 2010, our pro forma cash available for distribution for the twelve months ended June 30, 2011, would have been approximately $73.4 million. These amounts would have been insufficient to make the initial quarterly distribution of $ per unit per quarter (or $ per unit on an annualized basis) on all of our common units during such periods. We estimate that our pro forma cash available for distribution for the fiscal year ended September 30, 2010 and the nine months ended June 30, 2011 would have been sufficient to pay only % and %, respectively, of the full initial quarterly distribution on all of our common units for those periods.

Unaudited pro forma cash available for distribution includes direct, incremental administrative expenses of approximately $3.0 million that we expect to incur as a result of being a publicly traded partnership. These incremental expenses include, costs associated with SEC reporting requirements, including annual and quarterly reports to common unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, Sarbanes-Oxley Act compliance, NYSE listing, registrar and transfer agent fees, director and officer liability insurance costs, and director compensation. Such incremental administrative expenses are not reflected in our historical and pro forma financial statements.

We based the pro forma financial statements upon currently available information and specific estimates and assumptions. The pro forma cash amounts do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. Furthermore, cash available for distribution is primarily a cash accounting concept, while our unaudited pro forma financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma cash available for distribution only as a general indication of the amount of cash available for distribution that we might have generated had we been formed and completed the transactions contemplated in this prospectus in earlier periods.
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The footnotes to the table below provide additional information about the pro forma adjustments and should be read along with the table.

## Inergy Midstream, L.P.

### Unaudited Pro Forma Cash Available for Distribution

<table>
<thead>
<tr>
<th>Year Ended</th>
<th>Twelve Months Ended</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>September 30, 2010</td>
</tr>
<tr>
<td></td>
<td>($ in millions)</td>
</tr>
</tbody>
</table>

### Pro Forma Net Income Attributable to Partners

<table>
<thead>
<tr>
<th>Add:</th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Depreciation and amortization</td>
<td>36.2</td>
<td>36.8</td>
</tr>
<tr>
<td>Interest expense, net (1)</td>
<td>1.3</td>
<td>1.5</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated ITDA (2)</td>
<td>(0.2)</td>
<td>—</td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense (3)</td>
<td>2.7</td>
<td>1.7</td>
</tr>
<tr>
<td>Loss on disposal of assets</td>
<td>0.9</td>
<td>—</td>
</tr>
<tr>
<td>Transaction costs</td>
<td>0.2</td>
<td>—</td>
</tr>
<tr>
<td>Income tax expense</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

### Pro Forma Adjusted EBITDA (4)

<table>
<thead>
<tr>
<th>Add:</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated incremental administrative expense (5)</td>
<td>3.0</td>
<td>3.0</td>
</tr>
<tr>
<td>Cash interest expense (6)</td>
<td>1.3</td>
<td>1.5</td>
</tr>
<tr>
<td>Cash tax expense (7)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Maintenance capital expenditures</td>
<td>0.3</td>
<td>2.5</td>
</tr>
<tr>
<td>Expansion capital expenditures (8)</td>
<td>49.5</td>
<td>73.0</td>
</tr>
</tbody>
</table>

### Adjustments to reconcile pro forma Adjusted EBITDA to pro forma cash available for distribution:

<table>
<thead>
<tr>
<th>Less:</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash intere st expense (6)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Maintenance capital expenditures</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Expansion capital expenditures (8)</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

### Pro Forma Cash Available for Distribution

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Annualized initial quarterly distributions per unit</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Distributions to public common unitholders</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Distributions to NRGY—common units</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Total distributions</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

### Excess (shortfall)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent of initial quarterly distributions payable to common unitholders</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

---

(1) Interest expense is based upon our estimates of: (i) average borrowings under our revolving credit facility of $104.8 million during the fiscal year ended September 30, 2010, and $116.5 million during the twelve months ended June 30, 2011; (ii) interest incurred at a rate of 3.5% per annum (based on LIBOR rates during the period plus a margin); and (iii) commitment fees on the unused portion of our revolving credit facility of 0.375% per annum. Interest expense also includes the amortization of debt issuance costs of approximately $ million per year incurred in connection with our revolving credit facility.

(2) ITDA means interest expense, taxes, depreciation and amortization expense.

(3) Represents expense associated with grants under NRGY's long-term incentive plan to employees that are dedicated to our operations.

(4) Adjusted EBITDA is defined in “Summary—Non-GAAP Financial Measures.”

(5) Represents estimated incremental cash expense associated with our being a publicly traded partnership.

(6) Cash interest expense reflects our interest expense less the non-cash amortization of deferred financing costs incurred in connection with our revolving credit facility.

(7) As a limited liability company, we did not pay income tax during the applicable period.
Expansion capital expenditures for the fiscal year ended September 30, 2010, and for the twelve months ended June 30, 2011, were $49.5 million and $73.0 million, respectively, and were primarily incurred to fund our growth projects. We assumed that these capital expenditures were funded by borrowings on our revolving credit facility.
Estimated Cash Available for Distribution for the Twelve Months Ending December 31, 2012

We forecast that our estimated cash available for distribution during the twelve months ending December 31, 2012 will be approximately $123.5 million. This amount would exceed by $ the amount needed to pay the initial quarterly distribution of $ per unit on all of our common units for each quarter in the four quarters ending December 31, 2012.

We are providing the forecast of Estimated Cash Available for Distribution to supplement our historical and pro forma financial statements in support of our belief that we will have sufficient cash available to allow us to pay cash distributions on all of our common units for each quarter in the twelve months ending December 31, 2012 at the initial quarterly distribution rate. Please read “—Assumptions and Considerations” for further information as to the assumptions we have made for the forecast. Please read “Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies” for information as to the accounting policies we have followed for the financial forecast.

Our forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending December 31, 2012. We believe that our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results will be achieved. If our estimates are not achieved, we may not be able to pay distributions on our common units at the initial quarterly distribution rate of $ per unit each quarter (or $ per unit on an annualized basis) or any other rate. The assumptions and estimates underlying the forecast are inherently uncertain and, though we consider them reasonable as of the date of this prospectus, are subject to a wide variety of significant business, economic and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the forecast, including, among others, risks and uncertainties contained in “Risk Factors.” Accordingly, there can be no assurance that the forecast is indicative of our future performance or that actual results will not differ materially from those presented in the forecast. Inclusion of the forecast in this prospectus should not be regarded as a representation by any person that the results contained in the forecast will be achieved.

We have prepared the following forecast to present the estimated cash available for distribution to our common unitholders during the forecasted period. The accompanying prospective financial information was not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in our view, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management’s knowledge and belief, the expected course of action and our expected future financial performance. However, this information is not necessarily indicative of future results.

Neither our independent registered public accounting firm, nor any other independent accountants, have compiled, examined or performed any procedures with respect to the prospective financial information contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and assume no responsibility for, and disclaim any association with, the prospective financial information. The independent registered public accounting firm’s report included in this prospectus relates to historical financial information. It does not extend to prospective financial information and should not be read to do so.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast or the assumptions used to prepare the forecast to reflect events or circumstances after the completion of this offering. In light of this, the statement that we believe that we will have sufficient cash available for distribution to allow us to make the full initial quarterly distribution on all of our outstanding common units for each quarter through December 31, 2012, should not be regarded as a representation by us, the underwriters or any other person that we will make such distribution. Therefore, you are cautioned not to place undue reliance on this information.
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Inergy Midstream, L.P.
Estimated Cash Available for Distribution

<table>
<thead>
<tr>
<th></th>
<th>12 Months Ending December 31, 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenue</strong></td>
<td></td>
</tr>
<tr>
<td>Firm storage</td>
<td>$107.0</td>
</tr>
<tr>
<td>Transportation</td>
<td>$42.5</td>
</tr>
<tr>
<td>Hub services</td>
<td>$11.4</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>$160.9</td>
</tr>
<tr>
<td><strong>Cost of Services Sold</strong> (excluding depreciation and amortization as shown below)</td>
<td></td>
</tr>
<tr>
<td>Storage</td>
<td>$7.4</td>
</tr>
<tr>
<td>Transportation</td>
<td>$4.2</td>
</tr>
<tr>
<td><strong>Gross Profit</strong></td>
<td>$149.3</td>
</tr>
<tr>
<td><strong>Operating Expenses</strong></td>
<td></td>
</tr>
<tr>
<td>Operating and administrative</td>
<td>$23.0</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>$54.2</td>
</tr>
<tr>
<td>Total Operating Expenses</td>
<td>$77.2</td>
</tr>
<tr>
<td><strong>Operating Income</strong></td>
<td></td>
</tr>
<tr>
<td>Interest expense, net (1)</td>
<td>$72.1</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>$69.7</td>
</tr>
</tbody>
</table>

Adjustments to reconcile net income to estimated Adjusted EBITDA:

| Add:                                             |
|----------------------------------|----------------------------------|
| Income tax expense (2)            |                                 |
| Interest expense, net             | $2.4                             |
| Depreciation and amortization expense | $54.2                          |
| Long-term incentive and equity compensation expense (3) | $1.6                            |
| **Estimated Adjusted EBITDA (4)** | $127.9                           |

Adjustments to reconcile estimated Adjusted EBITDA to estimated cash available for distribution:

<table>
<thead>
<tr>
<th>Less:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash interest expense (5)</td>
</tr>
<tr>
<td>Estimated expansion capital expenditures (1)</td>
</tr>
<tr>
<td>Estimated maintenance capital expenditures</td>
</tr>
<tr>
<td><strong>Add:</strong></td>
</tr>
<tr>
<td>Borrowings to fund expansion capital expenditures</td>
</tr>
<tr>
<td>Estimated Cash Available for Distribution</td>
</tr>
</tbody>
</table>

**Annualized initial quarterly distributions per unit**

**Distributions to public common unitholders**

**Total distributions**

Excess of cash available for distribution over aggregate annualized initial quarterly cash distributions

Calculation of estimated Adjusted EBITDA necessary to pay aggregate annualized initial quarterly cash distributions:

| Estimated Adjusted EBITDA | $127.9 |

Excess of cash available for distribution over annualized initial quarterly cash distributions

Estimated Adjusted EBITDA necessary to pay aggregate annualized initial quarterly cash distributions

| Estimated Adjusted EBITDA necessary to pay aggregate annualized initial quarterly cash distributions | $ |
(1) Cash paid for capitalized interest is treated as an “expansion capital expenditure” for purposes of our determination of cash available for distribution. Estimated cash paid to settle capitalized interest during the period is approximately $4.3 million and is included as a component of “Expansion capital expenditures.”

(2) As a limited partnership, we do not expect to pay income tax during the forecast period.

(3) Represents expense associated with grants under NRGY’s long-term incentive plan to employees that are dedicated to our operations.

(4) EBITDA and Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with generally accepted accounting principles as those items are used to measure operating performance, liquidity, and our ability to service debt obligations. Please read “Summary—Non-GAAP Financial Measures.”

(5) Cash interest expense is book interest expense less amortization of deferred financing costs.

Assumptions and Considerations

We believe our estimated available cash for distribution for the twelve months ending December 31, 2012 will not be less than $123.5 million. This amount of estimated minimum available cash for distribution is approximately $57.7 million, or approximately 88%, more than the unaudited pro forma available cash for distribution for the fiscal year ended September 30, 2010, and approximately $50.1 million, or approximately 68%, more than the unaudited pro forma available cash for distribution for the twelve month period ended June 30, 2011. Substantially all of this increase in available cash for distribution is attributable to additional storage and transportation capacity we recently acquired or expect to place into service and for which we have secured contracts for substantially all incremental capacity, as described below. Our estimates do not assume any incremental revenue, expenses or other costs associated with potential future acquisitions.

While the assumptions disclosed in this prospectus are not all-inclusive, the assumptions listed are those that we believe are significant to our forecasted results of operations and any discussions not discussed below were not deemed significant. We believe our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results, including without limitation, the anticipated in service dates of our growth projects, will be achieved.

The forecast of our results of operations for the twelve months ending December 31, 2012, assumes and reflects:

- construction of the MARC I pipeline, a fully contracted natural gas transmission pipeline with 550 MMcf/d of interstate transportation service, which we expect to complete and place into service in July 2012 with contracts extending to 2022;
- completion of our North/South expansion project, which involves the installation of additional compression facilities that will enable us to provide approximately 325 MMcf/d of interstate transportation service on a fully contracted basis, which we expect to complete and place into service in October 2011 with contracts extending to 2016;
- development of a 2.1 million barrel NGL storage facility located near Watkins Glen, New York, which is approximately 95% contracted and which we expect to complete and place into service in April 2012 with a contract extending to 2016; and
- the impact of our acquisition of our Seneca Lake natural gas storage facility in July 2011 and its expansion by an additional 0.6 Bcf of working gas storage capacity, which we expect to complete and place into service by December 2012.
Revenue

We estimate that our total revenues for the twelve months ending December 31, 2012 will be approximately $160.9 million, as compared to approximately $94.7 million and $105.9 million for the fiscal year ended September 30, 2010, and the twelve months ended June 30, 2011, respectively. Our forecast is based primarily on the following assumptions:

Firm Storage

We estimate that approximately 67%, or approximately $107.0 million, of our total revenue will be generated from firm storage services. This compares to approximately 85%, or approximately $81 million, of our total revenues that were generated from firm storage revenues during the fiscal year ended September 30, 2010, and approximately 85%, or approximately $89.7 million, of our total revenues that were generated from firm storage revenues during the twelve months ended June 30, 2011. Furthermore, we have assumed that:

Natural Gas

- approximately 72% of our total firm storage revenue will be generated from firm storage services provided under contracts in existence as of August 23, 2011, that expire after the forecast period; and
- approximately 9% of our total firm storage revenue is expected to be generated from firm storage contracts covering approximately 5.0 Bcf of working gas capacity entered into or renewed during the forecast period, including the 0.6 Bcf of additional capacity (Gallery 2) to be placed into service at our Seneca Lake storage facility on December 1, 2012. We have assumed we will earn storage rates under new and renewed contracts that are consistent with rates under new contracts and contract extensions over the last 12 months.

NGL

- approximately 18% of our total firm storage revenue will be generated from NGL storage services provided under contracts in existence as of August 23, 2011, that expire after the forecast period, including (a) approximately 1.5 million barrels, or 100%, of the capacity at our Bath storage facility, and (b) two million barrels of storage at our 2.1 million barrel Watkins Glen facility under development, which we expect to place into service on April 1, 2012.

Transportation

We estimate that approximately 26%, or approximately $42.5 million, of our total revenue will be generated from firm transportation services. This compares to approximately 13%, or approximately $12.1 million, of our total revenues that were generated from transportation revenues during the fiscal year ended September 30, 2010, and approximately 12%, or approximately $12.5 million, of our total revenues that were generated from transportation revenues during the twelve months ended June 30, 2011. Our estimate for the forecast period assumes a significant increase in firm wheeling and transportation service revenue resulting from the completion and placement into service of our North/South Project and MARC 1 pipeline, as well as the operation of our intrastate pipeline located in New York that we purchased in July 2011. Furthermore, we have assumed that:

- approximately 34% of our total transportation revenue will be generated from services provided under binding agreements covering 325 MMcf of interstate wheeling capacity, commencing October 1, 2011;
- approximately 45% of our total transportation revenue will be generated from services provided under binding agreements covering 550 MMcf of interstate transportation capacity over the MARC 1 pipeline, commencing July 1, 2012; and
- approximately 11% of our total transportation revenue will be generated from services provided under a binding agreement covering 30 MMcf of intrastate firm transportation capacity throughout calendar 2012.
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Hub Services

We estimate that approximately 7%, or approximately $11.4 million, of our total revenue will be generated from natural gas hub services. This compares to approximately 2%, or approximately $1.6 million, of our total revenues that were generated from hub service revenues during the fiscal year ended September 30, 2010, and approximately 3%, or approximately $3.7 million, of our total revenues that were generated from hub service revenues during the twelve months ended June 30, 2011. We have also assumed that we will earn revenues that are consistent with both our expanded asset base (including improved interconnectivity resulting from projects placed into service in 2011 and 2012) and hub service revenue generated in the last twelve months.

Cost of Services Sold

Our cost of services sold consists primarily of utility and fuel expenses and the costs to obtain transportation capacity on certain interstate pipelines. We estimate that our cost of services sold will be approximately $11.6 million for the twelve months ending December 31, 2012, as compared to approximately $12.0 million and $14.2 million for the fiscal year ended September 30, 2010, and the twelve months ended June 30, 2011, respectively.

Operating and Administrative Expenses

We estimate that operating and administrative expenses will be approximately $23.0 million for the twelve months ending December 31, 2012, as compared to approximately $15.0 million and $13.8 million for the fiscal year ended September 30, 2010 and the twelve months ended June 30, 2011, respectively. The estimated operating and administrative expenses includes approximately $5.7 million from incremental expenses that we expect we will incur to support our expansion projects and the July 2011 Seneca Lake acquisition, plus approximately $3.0 million in incremental administrative expenses we will incur as a result of becoming a publicly traded partnership. Please read “Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Omnibus Agreement.”

Depreciation and Amortization

We estimate that depreciation and amortization expense will be approximately $54.2 million for the twelve months ending December 31, 2012, as compared to approximately $36.2 million and $36.8 million for the fiscal year ended September 30, 2010 and the twelve months ended June 30, 2011, respectively. Depreciation expense is expected to increase for the twelve months ending December 31, 2012, compared to the fiscal year ended September 30, 2010, and the twelve months ended June 30, 2011, due to the recent Seneca Lake acquisition and the expansion projects we expect to place into service during the forecast period.

Capital Expenditures

We estimate that total capital expenditures for the twelve months ending December 31, 2012, will be $120.1 million. This forecast is based on the following assumptions:

- Our estimated maintenance capital expenditures will be $2.0 million for the twelve months ending December 31, 2012, as compared to actual maintenance capital expenditures of approximately $0.3 million and $2.5 million for the fiscal year ended September 30, 2010 and the twelve months ended June 30, 2011, respectively. Our maintenance capital expenditures in the forecast period are relatively low in comparison to the size of our asset base because our storage and transportation assets and related equipment are relatively new. We expect to fund maintenance capital expenditures from cash generated by our operations.

- Our expansion capital expenditures will be approximately $118.1 million for the twelve months ending December 31, 2012, as compared to expansion capital expenditures incurred of approximately $49.5 million and $73.0 million for the fiscal year ended September 30, 2010, and the twelve months ended June 30, 2011, respectively. The $118.1 million of expansion capital expenditures anticipated to be spent during the forecast period are related to the MARC I pipeline and the NGL storage facility being developed at Watkins Glen, New York. We expect to fund our expansion capital expenditures with borrowings under our revolving credit facility.
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Financing
We estimate that interest expense will be approximately $2.4 million, net of $4.3 million in capitalized interest for the twelve months ending December 31, 2012. Our interest expense for the forecast period is based on the following assumptions:

- through December 31, 2012, we expect to fund our expansion capital expenditures primarily under our revolving credit facility, with an estimated weighted-average rate of 3.5%. This rate is based on a forecast of LIBOR rates during the period plus the margin and the anticipated commitment fees of 0.375% for the unused portion of our revolving credit facility;
- our re-borrowing of $80 million under our revolving credit facility to fund a distribution to NRGY for reimbursement of capital expenditures associated with our assets; and
- interest expense also includes the amortization of debt issuance costs of $1 million incurred in connection with our revolving credit facility.

Regulatory, Industry and Economic Factors
The forecast of our results of operations for the twelve months ending December 31, 2012 incorporates assumptions that (i) there will not be any new federal, state or local regulations or any new interpretations of existing regulations, that would materially impact our or our customers’ operations, and (ii) there will not be any major adverse economic changes in the portions of the energy industry in which we operate, or in general economic conditions, that would be materially adverse to our business during the forecast period.
PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2011, we distribute all of our available cash to common unitholders of record on the applicable record date. We will adjust the initial quarterly distribution for the period from the closing of this offering through December 31, 2011.

Definition of Available Cash

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- **less**, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our common unitholders for any one or more of the next four quarters;
- **plus**, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to common unitholders. Under our partnership agreement, working capital borrowings are borrowings that are made under a credit agreement, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Intent to Distribute the Initial Quarterly Distribution

We intend to distribute to the holders of common units on a quarterly basis at least the initial quarterly distribution of $ per unit, or $ per unit on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. However, there is no guarantee that we will pay the initial quarterly distribution on the common units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

General Partner Interest

Our general partner will not be entitled to distributions on its non-economic general partner interest.

Incentive Distribution Rights

NRGY will hold incentive distribution rights that entitle it to receive 50.0% of the cash we distribute from operating surplus (as defined below) in excess of the initial quarterly distribution. Any such distribution would be in addition to any distributions that NRGY may receive on any common units that it owns.
Operating Surplus and Capital Surplus

General

All cash distributed will be characterized as either “operating surplus” or “capital surplus.” Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus

We define operating surplus as:

- $ million (as described below); plus
- all of our cash receipts after the closing of this offering, excluding cash from interim capital transactions (as defined below under “Capital Surplus”); plus
- working capital borrowings made after the end of the period but on or before the date of determination of operating surplus for the period; plus
- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights), other than equity issued in this offering, to finance all or a portion of expansion capital expenditures in respect of the period from such financing until the earlier to occur of the date the capital asset commences commercial service and the date that it is abandoned or disposed of; plus
- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights), other than equity issued in this offering, to pay interest on debt incurred, or to pay distributions on equity issued, to finance the expansion capital expenditures referred to above, in each case, in respect of the period from such financing until the earlier to occur of the date the capital asset commences commercial service and the date that it is abandoned or disposed of; less
- all of our operating expenditures (as defined below) after the closing of this offering; less
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; less
- all working capital borrowings not repaid within twelve months after having been incurred; less
- any loss realized on disposition of an investment capital expenditure.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our common unitholders and is not limited to cash generated by our operations. For example, it includes a basket of $ million that will enable us, if we choose, to distribute as operating surplus cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

The proceeds of working capital borrowings increase operating surplus and repayments of working capital borrowings are generally operating expenditures, as described below, and thus reduce operating surplus when made. However, if a working capital borrowing is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will be excluded from operating expenditures because operating surplus will have been previously reduced by the deemed repayment.
We define operating expenditures in the partnership agreement, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to our general partner or its affiliates, payments made under interest rate hedge agreements or commodity hedge agreements (provided that (1) with respect to amounts paid in connection with the initial purchase of an interest rate hedge contract or a commodity hedge contract, such amounts will be amortized over the life of the applicable interest rate hedge contract or commodity hedge contract and (2) payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its stipulated settlement or termination date will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such interest rate hedge contract or commodity hedge contract), officer compensation, repayment of working capital borrowings, debt service payments and maintenance capital expenditures, provided that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the penultimate bullet point of the definition of operating surplus above when such repayment actually occurs;
- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions;
- distributions to our partners (including distributions in respect of our incentive distribution rights); or
- repurchases of equity interests except to fund obligations under employee benefit plans.

**Capital Surplus**

Capital surplus is defined in our partnership agreement as any distribution of available cash in excess of our operating surplus. Accordingly, capital surplus would generally be generated only by the following (which we refer to as “interim capital transactions”):

- borrowings other than working capital borrowings;
- sales of our equity and debt securities; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

**Characterization of Cash Distributions**

Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus from the closing of this offering through the end of the quarter immediately preceding that distribution. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As described above, operating surplus includes up to $ million, which does not reflect actual cash on hand that is available for distribution to our common unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to this amount of cash we receive in the future from interim capital transactions that would otherwise be distributed as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

**Capital Expenditures**

Maintenance capital expenditures are those capital expenditures required to maintain our long-term operating capacity or revenues. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.
Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or revenues over the long term. Expansion capital expenditures will also include interest (and related fees) on debt incurred to finance all or any portion of the construction of such capital improvement in respect of the period that commences when we enter into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of date any such capital improvement commences commercial service and the date that it is disposed of or abandoned. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of assets that are in excess of the maintenance of our existing operating capacity or revenues, but which are not expected to expand, for more than the short term, our operating capacity or revenues.

Neither investment capital expenditures nor expansion capital expenditures are included in operating expenditures, and thus will not reduce operating surplus. Because expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of the construction or improvement of a capital asset in respect of the period that begins when we enter into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of the date any such capital asset commences commercial service and the date that it is abandoned or disposed of, such interest payments also do not reduce operating surplus. Losses on disposition of an investment capital expenditure will reduce operating surplus when realized and cash receipts from an investment capital expenditure will be treated as a cash receipt for purposes of calculating operating surplus only to the extent the cash receipt is a return on principal.

Capital expenditures that are made in part for maintenance capital purposes, investment capital purposes and/or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner.

Distributions of Available Cash from Operating Surplus

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner:

- first, 100.0% to all common unitholders, pro rata, until we distribute for each common unit an amount equal to the initial quarterly distribution for that quarter; and
- thereafter, 50.0% to all common unitholders, pro rata, and 50.0% to NRGY in respect of the incentive distribution rights. Please read “—Incentive Distribution Rights” below.

The preceding discussion is based on the assumption that we do not issue additional classes of equity interests.

General Partner Interest

Our partnership agreement provides that our general partner will not be entitled to distributions that we make prior to our liquidation on its non-economic general partner interest.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive 50% of quarterly distributions of available cash from operating surplus after the initial quarterly distribution has been achieved. Upon the closing of this offering, NRGY will hold all of our incentive distribution rights and may transfer these rights without the consent of our common unitholders.
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Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and IDR holders based on the quarterly distribution level. The amounts set forth under “Marginal Percentage Interest in Distributions” are the percentage interests of the common unitholders and IDR holders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column “Total Quarterly Distribution Per Common Unit.” The percentage interests shown for our common unitholders and IDR Holders for the initial quarterly distribution are also applicable to quarter distribution amounts that are less than the initial quarterly distribution.

<table>
<thead>
<tr>
<th>Total Quarterly Distribution Per Common Unit</th>
<th>Marginal Percentage Interest in Distributions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Quarterly Distribution</td>
<td>Common Unitholders</td>
</tr>
<tr>
<td>$</td>
<td>100.0%</td>
</tr>
<tr>
<td>Thereafter above $</td>
<td>50.0%</td>
</tr>
</tbody>
</table>

NRGY’s Right to Reset Incentive Distribution Level

NRGY, as the initial holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial quarterly distribution and to reset, at a higher level, the initial quarterly distribution amount (upon which the incentive distribution payments to NRGY would be set). If NRGY transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. The following discussion assumes that NRGY holds all of the incentive distribution rights at the time that a reset election is made. The right to reset the initial quarterly distribution may be exercised, without approval of our common unitholders or the conflicts committee of the board of directors of our general partner, at any time when we have made cash distributions to the holders of the incentive distribution rights for the prior fiscal quarter. The reset initial quarterly distribution will be higher than the initial quarterly distribution prior to the reset such that there will be no incentive distributions paid under the reset initial quarterly distribution until cash distributions per unit following this event increase as described below.

In connection with the resetting of the initial quarterly distribution and the corresponding relinquishment by NRGY of incentive distribution payments based on the initial quarterly distribution prior to the reset, NRGY will be entitled to receive a number of newly issued common units based on a predetermined formula described below that takes into account the “cash parity” value of the cash distribution related to the incentive distribution rights received by NRGY for the quarter prior to the reset event as compared to the cash distribution per common unit for the prior quarter.

The number of common units that NRGY would be entitled to receive from us in connection with a resetting of the initial quarterly distribution then in effect would be equal to the quotient determined by dividing (x) the amount of cash distributions received by NRGY in respect of its incentive distribution rights for the quarter prior to the date of such reset election by (y) the amount of cash distributed per common unit for such quarter.

Following a reset election, the initial quarterly distribution amount will be reset to an amount equal to the cash distribution amount per unit for the quarter immediately preceding the reset election (which amount we refer to as the “reset initial quarterly distribution”) such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- **first**, 100.0% to all common unitholders, pro rata, until each common unitholder receives an amount per unit equal to 150.0% of the reset initial quarterly distribution for that quarter; and
- **thereafter**, 50.0% to all common unitholders, pro rata, and 50.0% to NRGY in respect of the incentive distribution rights.
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The following table illustrates the percentage allocation of available cash from operating surplus between the common unitholders and IDR holders (1) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (2) following a hypothetical reset of the initial quarterly distribution based on the assumption that the quarterly cash distribution amount per common unit for the quarter preceding the reset election was $.

<table>
<thead>
<tr>
<th>Initial quarterly distribution</th>
<th>Quarterly Distribution Per Common Unit Prior to Reset</th>
<th>Common Unitholders</th>
<th>IDR Holders</th>
<th>Quarterly Distribution Per Unit Following Hypothetical Reset</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$</td>
<td>100.0%</td>
<td>—</td>
<td>$</td>
</tr>
<tr>
<td>Thereafter</td>
<td>above $</td>
<td>50.0%</td>
<td>50.0%</td>
<td>above $</td>
</tr>
</tbody>
</table>

(1) This amount is 150% of the hypothetical reset initial quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the common unitholders and IDR holders in respect of incentive distribution rights based on the amount distributed for the quarter prior to the reset. The table assumes that immediately prior to the reset there would be common units outstanding and the distribution to each common unit would be $ per quarter for the quarter prior to the reset.

<table>
<thead>
<tr>
<th>Initial quarterly distribution</th>
<th>Quarterly Distribution Per Unit Prior to Reset</th>
<th>Cash Distributions to Common Unitholders Prior to Reset</th>
<th>Cash Distributions to IDR Holders Prior to Reset</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Thereafter</td>
<td>above $</td>
<td>$</td>
<td>$</td>
</tr>
</tbody>
</table>

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the common unitholders and IDR holders in respect of incentive distribution rights with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there would be common units outstanding and the distribution to each common unit would be $ . The number of common units to be issued to IDR holders upon the reset was calculated by dividing (1) the amount received by IDR holders in respect of incentive distribution rights for the quarter prior to the reset as shown in the table above, or $ million, by (2) the average available cash distributed on each common unit for the quarter prior to the reset as shown in the table above, or $ .

<table>
<thead>
<tr>
<th>Initial quarterly distribution</th>
<th>Quarterly Distribution Per Unit After Reset</th>
<th>Cash Distributions to Common Unitholders After Reset</th>
<th>Cash Distributions to IDR Holders After Reset</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>Thereafter</td>
<td>above $</td>
<td>$</td>
<td>$</td>
</tr>
</tbody>
</table>

NRGY, as the initial holder of all of the incentive distribution rights, will be entitled to cause the initial quarterly distribution amount to be reset on more than one occasion.
Distributions from Capital Surplus

**How Distributions from Capital Surplus Will Be Made**

Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- **first**, 100.0% to all common unitholders, pro rata, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price; and
- **thereafter**, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

The preceding paragraph assumes that we do not issue additional classes of equity interests.

**Effect of a Distribution from Capital Surplus**

Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the initial quarterly distribution will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the initial quarterly distribution after any of these distributions are made, it may be easier for NRGY to receive incentive distributions. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the initial quarterly distribution.

Once we distribute capital surplus on a common unit issued in this offering in an amount equal to the initial unit price, our partnership agreement specifies that the initial quarterly distribution will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from operating surplus, with 50.0% being paid to the holders of common units and 50.0% to IDR holders.

**Adjustment to the Initial Quarterly Distribution**

In addition to adjusting the initial quarterly distribution to reflect a distribution of capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the initial quarterly distribution; and
- the unrecovered initial unit price.

For example, if a two-for-one split of the common units should occur, the initial quarterly distribution and the unrecovered initial unit price would each be reduced to 50.0% of its initial level. Our partnership agreement provides that we do not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the initial quarterly distribution for each quarter may, in the sole discretion of the general partner, be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus our general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.
Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the common unitholders and the IDR holders, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in the partnership agreement. We will generally allocate any gain to the partners in the following manner:

- first, 100.0% to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price and (2) the amount of the initial quarterly distribution for the quarter during which our liquidation occurs; and
- thereafter, 50.0% to the common unitholders, pro rata, and 50.0% to IDR holders.

Manner of Adjustments for Losses

We will generally allocate any loss to the partners in the following manner:

- first, 50.0% to common unitholders, pro rata, and 50.0% to IDR holders, until the capital accounts of the IDR holders has been reduced to zero; and
- thereafter, 100.0% to common unitholders, pro rata.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for U.S. federal income tax purposes, unrecognized gain or loss resulting from the adjustments to the common unitholders and IDR holders in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the partners’ capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.
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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table presents our selected historical financial and operating data and selected pro forma financial data as of the dates and for the periods indicated. The selected historical financial data presented as of September 30, 2006, 2007 and 2008 and June 30, 2010 and for the fiscal years ended September 30, 2006 and 2007 are derived from our unaudited historical consolidated financial statements, which are not included in this prospectus. The selected historical financial data presented as of September 30, 2009 and 2010 and for the fiscal years ended September 30, 2008, 2009 and 2010 are derived from our audited historical consolidated financial statements that are included elsewhere in this prospectus. The selected historical financial data presented as of June 30, 2011 and for the nine months ended June 30, 2010 and 2011 are derived from our unaudited historical consolidated financial statements that are included elsewhere in this prospectus.

The selected pro forma financial data presented for the fiscal year ended September 30, 2010 and as of and for the nine months ended June 30, 2011 are derived from our unaudited pro forma condensed consolidated financial statements included elsewhere in this prospectus. Our unaudited pro forma condensed consolidated financial statements give pro forma effect to:

- the change in our organizational structure from a limited liability company to a limited partnership;
- the extinguishment of approximately $123.7 million of indebtedness that we owe to a subsidiary of NRGY, which will be treated as a capital contribution by NRGY to us;
- our assumption from NRGY of $28 million of indebtedness under a $200 million revolving credit facility of which we will repay $110 million from the net proceeds of this offering;
- our re-borrowing of $80 million under our revolving credit facility to fund a distribution to NRGY for reimbursement of capital expenditures associated with our assets;
- the issuance by us to NRGY of common units and all of our incentive distribution rights;
- the issuance by us to our general partner of a non-economic general partner interest in us; and
- the issuance by us to the public of common units and the use of the net proceeds from this offering as described under “Use of Proceeds.”

The unaudited pro forma balance sheet data assume the events listed above occurred as of June 30, 2011. The unaudited pro forma statement of operations data for the fiscal year ended September 30, 2010 assume the events listed above occurred as of October 1, 2009 and for the nine months ended June 30, 2011 assume the events listed above occurred as of October 1, 2010. We have not given pro forma effect to incremental external administrative expenses of approximately $3.0 million that we expect to incur annually as a result of being a publicly traded partnership. These incremental expenses include, costs associated with SEC reporting requirements, including annual and quarterly reports to common unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, Sarbanes-Oxley Act compliance, NYSE listing, registrar and transfer agent fees, director and officer liability insurance costs, and director compensation. Such incremental administrative expenses are not reflected in our historical and pro forma financial statements.

For a detailed discussion of the selected historical financial information contained in the following table, including factors impacting the comparability of information in the table, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The following table should also be read in conjunction with “Use of Proceeds” and our audited historical consolidated financial statements and our unaudited pro forma condensed consolidated financial statements included elsewhere in this prospectus. Among other things, the historical and unaudited pro forma condensed consolidated financial statements include more detailed information regarding the basis of presentation for the information in the following table.

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The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in our business as it is an important supplemental measure of our performance and liquidity. Adjusted EBITDA is not calculated or presented in accordance with GAAP. We explain this measure under "—Non-GAAP Financial Measures" and reconcile it to its most directly comparable financial measures calculated and presented in accordance with GAAP.

<table>
<thead>
<tr>
<th>Year Ended September 30,</th>
<th>Nine Months Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Statement of operations data:</strong></td>
<td></td>
</tr>
<tr>
<td>Revenue</td>
<td>$42.2</td>
</tr>
<tr>
<td>Cost of services sold (excluding depreciation and amortization as shown below):</td>
<td>16.3</td>
</tr>
<tr>
<td>Gross profit</td>
<td>25.9</td>
</tr>
<tr>
<td>Expenses:</td>
<td></td>
</tr>
<tr>
<td>Operating and administrative</td>
<td>5.6</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>11.5</td>
</tr>
<tr>
<td>(Gain) loss on disposal of assets</td>
<td>(0.3)</td>
</tr>
<tr>
<td>Operating income</td>
<td>9.1</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>0.3</td>
</tr>
<tr>
<td>Other income</td>
<td>-</td>
</tr>
<tr>
<td>Net income</td>
<td>8.8</td>
</tr>
<tr>
<td>Net income attributable to non-controlling partners</td>
<td>-</td>
</tr>
<tr>
<td>Net income attributable to member/partners</td>
<td>$8.8</td>
</tr>
</tbody>
</table>

**Balance sheet data (at end of period):**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th>$607.3</th>
<th>80.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total assets</td>
<td>$250.2</td>
<td>$371.3</td>
<td>$480.8</td>
<td>$561.0</td>
<td>$559.5</td>
<td>$560.5</td>
<td>$607.3</td>
<td>519.6</td>
</tr>
<tr>
<td>Total debt</td>
<td>-</td>
<td>-</td>
<td>-10.9</td>
<td>-8.3</td>
<td>-6.3</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Member’s/partners' capital</td>
<td>227.5</td>
<td>311.1</td>
<td>384.8</td>
<td>414.3</td>
<td>444.8</td>
<td>434.0</td>
<td>475.9</td>
<td>80.0</td>
</tr>
</tbody>
</table>

**Other financial data:**

<p>| | | | | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted EBITDA</td>
<td>$20.4</td>
<td>$35.3</td>
<td>$57.7</td>
<td>$57.7</td>
<td>$70.4</td>
<td>$49.2</td>
<td>$59.2</td>
<td>$70.4</td>
</tr>
<tr>
<td>Maintenance capital expenditures</td>
<td>0.2</td>
<td>0.1</td>
<td>0.2</td>
<td>-</td>
<td>0.3</td>
<td>0.3</td>
<td>2.5</td>
<td>-</td>
</tr>
<tr>
<td>Net cash provided by operating activities</td>
<td>13.1</td>
<td>34.3</td>
<td>62.9</td>
<td>59.5</td>
<td>83.5</td>
<td>56.8</td>
<td>65.2</td>
<td>-</td>
</tr>
<tr>
<td>Net cash used in investing activities</td>
<td>$(16.6)</td>
<td>$(103.4)</td>
<td>$(108.9)</td>
<td>$(74.1)</td>
<td>$(49.8)</td>
<td>$(38.4)</td>
<td>$(64.1)</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>4.3</td>
<td>68.2</td>
<td>48.9</td>
<td>15.3</td>
<td>(37.3)</td>
<td>(20.0)</td>
<td>8.3</td>
<td></td>
</tr>
<tr>
<td>--------------------------------</td>
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<tr>
<td><strong>Net cash provided by</strong></td>
<td></td>
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<td></td>
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</tr>
<tr>
<td><strong>(used in) financing</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>activities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>Operating data:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>Natural gas storage</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<td></td>
</tr>
<tr>
<td><strong>capacity (Bcf)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>% of revenue generated</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>from firm contracts</strong></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td><strong>66</strong></td>
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</tr>
</tbody>
</table>
## Non-GAAP Financial Measures

For a discussion of the non-GAAP financial measures EBITDA and Adjusted EBITDA, please read “Summary — Non-GAAP Financial Measures.” The following table presents a reconciliation of EBITDA and Adjusted EBITDA to their most directly comparable GAAP financial measures, on a historical basis and pro forma basis, as applicable, for each of the periods indicated.

### Reconciliation of net income to EBITDA and Adjusted EBITDA:

<table>
<thead>
<tr>
<th>Year Ended September 30,</th>
<th>Nine Months Ended June 30,</th>
<th>Pro Forma</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income attributable to member/partners</td>
<td>$ 8.8</td>
<td>$18.6</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>11.5</td>
<td>16.4</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>0.3</td>
<td>—</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated ITDA</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>EBITDA</strong></td>
<td>$20.6</td>
<td>$35.0</td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>(Gain) loss on disposal of assets</td>
<td>(0.3)</td>
<td>0.2</td>
</tr>
<tr>
<td>Transaction costs</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td>$20.4</td>
<td>$35.3</td>
</tr>
</tbody>
</table>

### Reconciliation of net cash provided by operating activities to EBITDA and Adjusted EBITDA:

<table>
<thead>
<tr>
<th>Year Ended September 30,</th>
<th>Nine Months Ended June 30,</th>
<th>Pro Forma</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net cash provided by operating activities</td>
<td>$13.1</td>
<td>$34.3</td>
</tr>
<tr>
<td>Net changes in working capital balances</td>
<td>6.9</td>
<td>0.9</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>0.3</td>
<td>—</td>
</tr>
<tr>
<td>Gain (loss) on disposal of assets</td>
<td>0.3</td>
<td>(0.2)</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated EBITDA</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>EBITDA</strong></td>
<td>$20.6</td>
<td>$35.0</td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>(Gain) loss on disposal of assets</td>
<td>(0.3)</td>
<td>0.2</td>
</tr>
<tr>
<td>Transaction costs</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td>$20.4</td>
<td>$35.3</td>
</tr>
</tbody>
</table>

(a) ITDA—Interest expense, taxes, depreciation and amortization expense.
MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of the historical financial condition and results of operations in conjunction with our historical consolidated financial statements and accompanying notes and our unaudited pro forma condensed consolidated financial statements included elsewhere in this prospectus. In addition, this discussion includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing from statements we make. Please read "Forward-Looking Statements." Factors that could cause actual results to differ include those risks and uncertainties that are discussed in "Risk Factors.

Overview

We are a fee-based, growth-oriented Delaware limited partnership formed by NRGY to own, operate, develop and acquire midstream energy assets. Our current asset base consists of natural gas and NGL storage and transportation assets located in the Northeast region of the United States. We own and operate four natural gas storage facilities located in New York and Pennsylvania that have an aggregate working gas storage capacity of 41.0 Bcf with high peak injection and withdrawal capabilities. We also own natural gas pipelines located in New York and Pennsylvania with 30 MMcf/d of intrastate transportation capacity and, upon completion of two pipeline projects that are currently under development, we will own 875 MMcf/d of interstate transportation capacity. In addition, we own and operate a 1.5 million barrel NGL storage facility located near Bath, New York. Our near-term strategy is to continue to develop a platform of interconnected natural gas assets that can be operated as an integrated Northeast storage and transportation hub.

Our business has expanded rapidly through internal growth initiatives and acquisitions since its inception in 2005. We have grown our natural gas storage capacity from 13.0 Bcf as of September 30, 2005 to 41.0 Bcf as of August 23, 2011, which does not include 38.4 Bcf of natural gas storage capacity owned by NRGY on the Texas Gulf Coast. We believe that our current asset base enables us to significantly expand our storage and transportation capacity through continued investment in attractive growth projects. We expect these growth projects will further increase connectivity among our natural gas facilities and with third-party pipelines, thereby resulting in increased demand for our services.

Our significant growth projects include:

• construction of the MARC I pipeline, a fully contracted natural gas transmission pipeline with 550 MMcf/d of interstate transportation service, which we expect to complete and place into service in July 2012 with contracts extending to 2022;
• completion of our North/South expansion project, which involves the installation of additional compression facilities that will enable us to provide approximately 325 MMcf/d of interstate transportation service on a fully contracted basis, which we expect to complete and place into service in October 2011 with contracts extending to 2016;
• development of a 2.1 million barrel NGL storage facility located near Watkins Glen, New York, which is approximately 95% contracted and which we expect to complete and place into service by April 2012 with a contract extending to 2016; and
• expansion of our Seneca Lake natural gas storage facility by an additional 0.6 Bcf of working gas storage capacity, which we expect to complete and place into service by December 2012.

Through our current assets, growth projects and potential acquisitions from NRGY and third parties, we believe we are well-positioned to benefit from the anticipated long-term growth in demand for natural gas and NGL storage and transportation services in the United States.
How We Generate Revenue

We generate revenue in our natural gas storage business almost exclusively through the provision of fee-based natural gas storage services to our customers. With the exception of our Seneca Lake facility, which we acquired in July 2011, our natural gas storage facilities were at least 95% contracted under fixed reservation fee agreements as of June 30, 2011. Our storage rates are regulated under FERC rate-making policies, which currently permit us to charge market-based rates for storage services at our Stagecoach, Thomas Corners and Seneca Lake facilities. Market-based rate authority for storage services allows us to negotiate rates with customers based on market demand. Our Steuben facility provides services at cost-based rates; however, we intend to file an application with the FERC by the end of calendar year 2011 to allow us to charge market-based rates at our Steuben facility.

We generate transportation revenue by providing fee-based transportation services to our customers. Our transportation services and rates have been authorized by the FERC or, if applicable, the New York State Public Service Commission, or NYPSC. The transportation services authorized under, or requested for authorization under, our FERC tariffs for the MARC I pipeline and for the North/South expansion project will be provided to our customers at negotiated rates subject to cost-of-service recourse rate options. Negotiated-rate authority for transportation services allows us to negotiate rates with customers based on market demand.

We provide NGL storage and related terminaling services at our Bath storage facility under market rates. We make cavern storage space available for a fixed monthly reservation fee that must be paid regardless of customer usage. We provide loading and unloading services and receive fees for such services.

Factors That Impact Our Business

A substantial majority of our revenues is derived from fixed reservation fees under multi-year contracts with a diverse portfolio of customers. We believe this contract structure and customer mix provides stability to our cash flow profile and substantially mitigates the risk to us of significant negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. We also believe that the strategic location of our assets in a high demand region significantly increases our ability to maintain the high percentage of earnings from fixed fees under multi-year contracts. We believe the current infrastructure for storage and transportation capacity in our market will continue to be undersupplied.

We believe the key factors that impact our business are (i) the anticipated long-term supply and demand for natural gas and NGLs in the markets we serve, which determine the amount of volatility in natural gas and NGL prices and drive month-to-month differentials in the forward curve for natural gas prices; (ii) our ability to capitalize on internal growth projects; (iii) the needs of our customers and the competitiveness of our service offerings; and (iv) government regulation, including our ability to obtain the permits required to build new infrastructure. These factors, discussed in more detail below, play an important role in how we evaluate our operations and implement our long-term strategies.

Supply and Demand for Natural Gas and NGLs

To effectively manage our business, we monitor our market areas for both short- and long-term changes in natural gas and NGL supply and demand and the relative adequacy of existing and planned storage and transportation infrastructure to meet these changing needs. In general, any imbalance that exists between supply and demand, whether long-term, seasonal or intermittent for either natural gas or NGLs, should support demand for storage services. We expect that demand for our storage services will increase during periods of supply and demand imbalances.

In addition, any factors that contribute to more frequent and severe imbalances between supply and demand, whether caused by supply or demand fluctuations, should increase volatility, inter-month differentials in natural gas and NGL prices and the need for and value of storage services. Because our facilities, in most instances,
connect supply (from local production or other pipelines) to storage and storage is connected to demand (either local industrial demand or other market-bound pipelines) through our transportation assets, any increase in either supply or demand should facilitate growth in our transportation business. Our storage and transportation services allow our customers to manage imbalances in supply and demand throughout the markets we serve. As changes in supply and demand dynamics take place, we attempt to adjust our service offerings in terms of price, duration, operating flexibility and other factors to meet the needs of our customers, in each case subject to any regulatory constraints or limitations (which, in the case of our natural gas storage and transportation services, are contained in FERC-approved tariffs).

Internal Growth Opportunities

Our current asset base enables us to significantly expand storage capacity and improve our facilities’ connectivity through continued investment in attractive growth projects. Our significant growth projects include (i) increasing transportation functionality and interconnectivity through our MARC I pipeline and North/South expansion project, which we also believe will facilitate greater interconnectivity between our natural gas storage assets in general, (ii) increasing NGL storage capacity by developing up to five million barrels of incremental NGL storage at our proposed Watkins Glen facility and (iii) adding 0.6 Bcf of natural gas storage capacity at our Seneca Lake facility. Consistent with our past practice, we began development of these projects after entering into binding agreements. Our capital budget supports ongoing growth initiatives that leverage the market positioning of our existing facilities and management’s experience in the storage and transportation business. We anticipate that these projects will allow us to better serve our customers’ storage and transportation needs, increase margins, enhance our ability to obtain contracts for the use of our assets and increase our interconnectivity to multiple pipelines, thereby reducing our dependence on any one or more third-party pipelines.

Customers

We store natural gas and NGLs and transport natural gas for a broad mix of customers, such as utilities (LDCs and electric utilities), marketers, producers, industrial users, pipelines and refiners. Utilities normally require a secure and reliable supply of natural gas over a sustained period of time to meet the needs of their customers. Frequently, utilities will enter into long-term firm storage and transportation contracts to ensure both a ready supply of natural gas and sufficient transportation capacity over the life of the contract. Marketers that generate income from buying and selling natural gas or NGLs use our services to capitalize on price differentials over time or between markets. Demand for our services from marketers typically increases with price volatility.

We continuously monitor the evolving needs of our customers, current and forecasted market conditions, and the competitiveness of our service offerings in order to maintain the proper balance between optimizing near-term earnings and cash flow and positioning our business for sustainable long-term growth.

Regulation

Government regulation, particularly regulation of natural gas storage and transportation assets, can have a significant impact on our business. For example, the permitting processes at all government levels, including the FERC, impact our ability to obtain the approvals and permits required to construct new infrastructure. These processes are increasingly impacted by political, environmental and other concerns that can significantly delay or increase the cost of obtaining the approvals and permits required to expand our operations. Other federal, state and local regulation can also impact our operations, cost structure and profitability, which could in turn impact our financial performance and our ability to make distributions to our common unitholders. As a result, we closely monitor regulatory developments affecting our business.

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Future Trends and Outlook

We expect our business to continue to be affected by several trends, including key trends described below. Our expectations are based on assumptions made by us and information currently available to us. If our underlying assumptions prove to be incorrect, actual results may vary materially from our expected results. Please read “Risk Factors.”

Growing Natural Gas Demand

Natural gas is a significant component of energy consumption in the United States. According to the EIA, natural gas consumption accounted for approximately 24% of all energy used in the United States in 2010, representing 24 Tcf of natural gas. The EIA estimates that over the next 27 years, total domestic energy consumption will increase by over 15%, with natural gas consumption directly benefiting from population growth, growth in cleaner-burning natural gas-fired electric generation and natural gas vehicles. We believe increasing demand for natural gas will drive the demand for additional natural gas storage and transportation infrastructure, particularly in high-demand markets like the Northeast.

Increasing Natural Gas Supply

We believe there will be ample supplies of natural gas for the foreseeable future from a combination of domestic production and pipeline imports. We also believe that forecast increases in domestic shale gas production, including local production from the Marcellus and Utica shale plays, will continue to drive demand for storage and transportation infrastructure as producers attempt to deliver shale gas and NGLs to demand markets.

Growth Opportunities

We expect to expand our storage and transportation capacity in the future. In addition, we will selectively pursue strategic acquisitions from NRGY or third parties that complement our existing asset base or provide attractive potential returns in new areas within our geographic footprint. Our long-term strategy includes operating qualifying income producing midstream assets, including natural gas and NGL storage and transportation assets, throughout North America. We believe that we will be well positioned to acquire assets from third parties should such opportunities arise, and identifying and executing acquisitions will be a key part of our strategy.

Market Volatility

Our business can be positively or negatively affected by the widening or narrowing of seasonal spreads, extended periods of significant or little volatility and economic expansions or downturns. Volatility in natural gas prices is primarily caused by supply and demand imbalances. Historically, natural gas price volatility has been particularly pronounced in the Northeast region of the United States. Because the Northeast region is less proximate to natural gas supply, sharp increases in demand can cause larger increases in price volatility relative to markets that are closer to greater amounts of natural gas supply.

Barriers to Entry

Although competition within the midstream industry is robust, significant barriers to entry exist in the natural gas and NGL storage and transportation businesses. In particular, there is a scarcity of unexploited reservoirs located near pipeline infrastructure, natural gas and NGL supply sources and end-user markets that have the capacity necessary to store natural gas and NGLs economically. Operational challenges and high upfront capital costs associated with the development of natural gas and NGL storage and transportation assets also exist. They include obtaining title to land and permits to operate, constructing facilities for injecting, storing and withdrawing natural gas and NGLs and meeting high cushion gas requirements. Moreover, significant industry skills are required to identify, construct and operate successful natural gas and NGL infrastructure, and many of these skills are uncommon.
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Supply of Storage Capacity

An important factor in determining the value of storage and therefore the rates we are able to charge for new contracts or contract renewals is whether a surplus or shortfall of storage capacity exists relative to the overall demand for storage services in a given market area. In general, in the markets like the Northeast where we believe storage is in short supply, storage values will be higher on a relative basis than in regions that are oversupplied with storage capacity. The extent to which markets are undersupplied or oversupplied will fluctuate in response to significant variations in natural gas and NGL supply and demand. We believe the current infrastructure for storage and transportation capacity in our market will continue to be undersupplied.

Increased Costs as a Result of Being a Public Entity

As a result of being a publicly-traded limited partnership, we will incur incremental administrative expenses that are not reflected in our historical financial statements. These costs include costs associated with annual and quarterly reports to common unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, Sarbanes-Oxley compliance, NYSE listing, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation. We expect our incremental administrative expenses associated with being a publicly-traded limited partnership to total approximately $3.0 million per year.

How We Evaluate Our Operations

We evaluate our business performance on the basis of the following key measures:

- revenues derived from firm storage contracts and the percentage of physical capacity deliverability sold;
- revenues derived from transportation contracts and the percentage of physical capacity sold;
- our operating and administrative expenses; and
- our EBITDA and Adjusted EBITDA.

We do not utilize depreciation, depletion and amortization expense in our key measures, because we focus our performance management on cash flow generation and our assets have long useful lives.

Firm Storage Contracts

A substantial majority of our revenues is derived from storage services we provide under firm contracts. We seek to maximize the portion of our physical capacity sold under firm contracts. With respect to our natural gas storage operations, to the extent that physical capacity that is contracted for firm service is not being fully utilized, we attempt to contract available capacity for interruptible service. The table below sets forth the percentage of physical capacity or deliverability sold under firm storage contracts:

<table>
<thead>
<tr>
<th>Storage Facility</th>
<th>Percentage Contractually Committed</th>
<th>Weighted-Average Maturity (Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stagecoach (Natural Gas)</td>
<td>95%</td>
<td>2015</td>
</tr>
<tr>
<td>Thomas Corners (Natural Gas)</td>
<td>100%</td>
<td>2015</td>
</tr>
<tr>
<td>Seneca Lake (Natural Gas)</td>
<td>59%</td>
<td>2018</td>
</tr>
<tr>
<td>Steuben (Natural Gas)</td>
<td>100%</td>
<td>2013</td>
</tr>
<tr>
<td>Bath (NGL)</td>
<td>100%</td>
<td>2016</td>
</tr>
</tbody>
</table>

(1) We did not acquire Seneca Lake until July 2011 and are currently in the process of leasing out the remaining storage capacity at the facility.

(2) We have contracted 100% of the storage capacity at our Bath facility to Inergy Propane. Please read “Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions.”
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Transportation Contracts

Our New York intrastate pipeline that we acquired in July 2011, together with our MARC I pipeline and North/South expansion project when completed, are expected to provide material earnings to our operations. We will seek to maximize the portion of physical capacity sold on the pipelines under firm contracts. To the extent the physical capacity that is contracted for firm service is not being fully utilized, we plan to contract available capacity on an interruptible basis. Our existing transportation assets and our transportation projects under development are 100% contracted and committed.

Operating and Administrative Expenses

Operating and administrative expenses consist primarily of vehicle costs, including fuel, repair and maintenance costs, and wages. These expenses typically do not vary significantly based upon the amount of natural gas or NGLs that we store or transport. We obtain in-kind fuel reimbursements from natural gas shippers in accordance with our FERC gas tariffs and individual contract terms. Our timing of expenditures may fluctuate with planned maintenance activities that take place during off-peak periods. Changes in regulation may also impact our expenditures. Additionally, fluctuations in project development costs are impacted by the level of development activity during a period. Following this offering, we expect our operating and administrative expenses will increase substantially as a result of an increase in legal and accounting costs and related public company regulatory and compliance expenses.

EBITDA and Adjusted EBITDA

We define EBITDA as income before income taxes, plus net interest expense and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA excluding the gain or loss on the disposal of assets, long-term incentive and equity compensation expenses, and transaction costs. Transaction costs are third-party professional fees and other costs that are incurred in conjunction with closing a transaction.

Adjusted EBITDA is a non-GAAP supplemental financial measure that management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or financing methods;
- the ability of our assets to generate sufficient cash flow to make distributions to our common unitholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment in various opportunities.

EBITDA and Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure operating performance, liquidity, and our ability to service debt obligations. We believe that EBITDA provides additional information for evaluating our ability to make distributions to our common unitholders and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information for evaluating our financial performance without regard to our financing methods, capital structure, and historical cost basis. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA and Adjusted EBITDA or similarly titled measures used by other corporations or partnerships in our industry, thereby diminishing such measures’ utility.

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Results of Operations


The following table summarizes the consolidated statement of operations components for the nine months ended June 30, 2011 and 2010, respectively (in millions):

<table>
<thead>
<tr>
<th></th>
<th>Nine Months Ended June 30, 2011</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>In Dollars</td>
<td>Percentage</td>
</tr>
<tr>
<td>Revenue</td>
<td>$80.3</td>
<td>$11.2</td>
</tr>
<tr>
<td>Cost of services sold</td>
<td>$11.9</td>
<td>$2.2</td>
</tr>
<tr>
<td>Gross profit</td>
<td>$68.4</td>
<td>$9.0</td>
</tr>
<tr>
<td>Operating and administrative expenses</td>
<td>$10.1</td>
<td>$1.2</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>$27.3</td>
<td>$0.6</td>
</tr>
<tr>
<td>Loss on disposal of assets</td>
<td>$0.9</td>
<td></td>
</tr>
<tr>
<td>Operating income</td>
<td>$31.0</td>
<td>$10.5</td>
</tr>
<tr>
<td>Net income attributable to non-controlling partners</td>
<td>$0.8</td>
<td></td>
</tr>
<tr>
<td>Net income attributable to member/partners</td>
<td>$31.0</td>
<td>$19.7</td>
</tr>
</tbody>
</table>

* Not meaningful

Revenue. Revenues for the nine months ended June 30, 2011, were $80.3 million, an increase of $11.2 million, or 16.2%, from $69.1 million during the same nine-month period in 2010.

Revenues from firm storage were $67.3 million for the nine months ended June 30, 2011, an increase of $8.7 million, or 14.8%, from $58.6 million during the same nine-month period in 2010. Natural gas firm storage revenues increased $7.5 million primarily due to the commencement of Thomas Corners storage contracts in April 2010. NGL revenues increased $1.2 million primarily related to a change in the mix of customers at the Bath facility and an overall increase in the storage fee rates charged to new customers.

Revenues from transportation were $9.5 million for the nine months ended June 30, 2011, an increase of $0.4 million, or 4.4%, from $9.1 million during the same nine-month period in 2010. This increase resulted primarily from a change in rates charged for transportation.

Revenues from hub services were $3.5 million for the nine months ended June 30, 2011, an increase of $2.1 million, or 150.0%, from $1.4 million during the same nine-month period in 2010. This increase resulted from an increase in interruptible services at our Stagecoach facility due to an increase in demand.

Cost of Services Sold. Cost of services sold for the nine months ended June 30, 2011, was $11.9 million, an increase of $2.2 million, or 22.7%, from $9.7 million during the same nine-month period in 2010.

Storage cost of services sold was $6.8 million for the nine months ended June 30, 2011, an increase of $2.2 million, or 47.8%, from $4.6 million during the same nine-month period in 2010. Natural gas storage cost increased $1.0 million and NGL storage cost increased $1.2 million. The increase in natural gas storage cost was primarily due to an increase in compression costs during the current period. NGL storage cost of services sold increased $1.2 million due to a decrease in fuel-in-kind collections.

Transportation cost of services sold was $5.1 million for the nine months ended June 30, 2011 and 2010.

Our storage cost of services sold consists primarily of direct costs to run the storage facilities, including electricity, contractor and fuel costs. Our transportation cost of services sold consists of our costs to procure firm transportation capacity on certain pipelines. These costs are offset by any fuel-in-kind collections made during
<table>
<thead>
<tr>
<th>Net income attributable to member/partners</th>
<th>$ 30.6</th>
<th>$ 28.3</th>
<th>$ 2.3</th>
<th>8.1%</th>
</tr>
</thead>
<tbody>
<tr>
<td>* Not meaningful</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>
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Revenue. Revenues in fiscal 2010 were $94.7 million, an increase of $7.2 million, or 8.2%, from $87.5 million in fiscal 2009.

Revenues from firm storage were $81.0 million in fiscal 2010, an increase of $8.9 million, or 12.3%, from $72.1 million in fiscal 2009. Natural gas firm storage contributed $8.2 million of the increase, primarily resulting from the in-servicing of our Thomas Corners facility and the related firm storage contracts. NGL revenues increased $0.7 million in fiscal 2010, primarily attributable to an increase in storage contracts with a related party.

Revenues from transportation were $12.1 million in fiscal 2010, a decrease of $0.1 million, or 0.8%, from $12.2 million in fiscal 2009.

Revenues from hub services were $1.6 million in fiscal 2010, a decrease of $1.6 million, or 50.0%, from $3.2 million in fiscal 2009. This decrease resulted from a decline in demand for interruptible services in the period.

Cost of Services Sold. Cost of services sold for fiscal 2010 was $12.0 million, a decrease of $5.8 million, or 32.6%, from $17.8 million in fiscal 2009.

Storage cost of services sold was $5.2 million, a decrease of $5.8 million, or 52.7%, from $11.0 million in fiscal 2009. Natural gas firm storage contributed $4.1 million of the decrease primarily due to lower compression costs at our Stagecoach facility. NGL storage cost of services sold decreased $1.7 million in fiscal 2010, primarily attributable to an increase in fuel-in-kind collections. Our fuel-in-kind collections during the 2010 period exceeded our cost of services sold.

Transportation cost of services sold was $6.8 million in fiscal 2010 and 2009.

Our storage cost of services sold consists primarily of direct costs to run the storage facilities, including power, contractor and fuel costs. Our transportation cost of services sold consists of our costs to procure firm transportation capacity on certain pipelines. These costs are offset by any fuel-in-kind collections made during the period. Other costs incurred in conjunction with these services are included in operating and administrative expense and depreciation and amortization expense and consist primarily of depreciation, vehicle costs, including fuel, repair and maintenance costs, and wages. Depreciation expense for storage amounted to $32.2 million and $26.1 million for fiscal 2010 and 2009, respectively. Vehicle costs and wages amounted to $1.7 million and $1.4 million for fiscal 2010 and 2009, respectively. Because we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of services sold, our gross profit may not be comparable to other entities in our lines of business if they include these costs in cost of services sold.

Gross Profit. Gross profit for fiscal 2010 was $82.7 million, an increase of $13.0 million, or 18.7%, from $69.7 million during fiscal 2009.

Storage gross profit was $77.4 million in fiscal 2010 compared to $64.3 million in fiscal 2009, an increase of $13.1 million, or 20.4%. Natural gas storage gross profit increased $10.7 million primarily due to our Thomas Corners facility being placed into service and lower compression costs at our Stagecoach facility. NGL gross profit increased $2.4 million primarily attributable to an increase in fuel-in-kind collections. Storage gross profit consists of firm storage and hub services.

Transportation gross profit was $5.3 million in fiscal 2010, a decrease of $0.1 million, or 1.9%, from $5.4 million in fiscal 2009.

Operating and Administrative Expenses. Operating and administrative expenses were $15.0 million in fiscal 2010 compared to $10.8 million in fiscal 2009. This $4.2 million, or 38.9%, increase in operating expenses was primarily attributable to an increase from the prior year in the amount of long-term incentive and equity compensation.

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**Depreciation and Amortization**. Depreciation and amortization increased to $36.2 million in fiscal 2010 from $29.2 million in fiscal 2009. This $7.0 million, or 24.0%, increase resulted primarily from placing our Thomas Corners facility into service.

**Loss on Disposal of Assets**. Loss on disposal of assets increased to $0.9 million in fiscal 2010. There was no loss on disposal of assets in fiscal 2009. The loss recognized during fiscal 2010 resulted from the abandonment of a development project.

**Net Income Attributable to Non-Controlling Partners**. We acquired a majority interest (approximately 55%) in the operations of Steuben Gas when we acquired 100% of the membership interest in ASC in October 2007. In January 2010, we acquired an additional 25% interest in Steuben Gas and in each of April 2010 and July 2010, we acquired an additional 10% interest in Steuben Gas. These acquisitions gave us 100% ownership of Steuben Gas.

**Net Income Attributable to Member/Partners**. Net income for fiscal 2010 was $30.6 million compared to net income for fiscal 2009 of $28.3 million. The $2.3 million, or 8.1%, increase in net income was primarily attributable to higher gross profit, partially offset by increased depreciation and amortization and operating and administrative expenses.

**EBITDA and Adjusted EBITDA**. The following tables summarize EBITDA and Adjusted EBITDA for the fiscal years ended September 30, 2010 and 2009, respectively (in millions):

<table>
<thead>
<tr>
<th>EBITDA:</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income attributable to member/partners</td>
<td>$30.6</td>
<td>$28.3</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated ITDA <em>(a)</em></td>
<td>(0.2)</td>
<td>(0.5)</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>EBITDA</strong></td>
<td>$66.6</td>
<td>$57.0</td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>2.7</td>
<td>0.7</td>
</tr>
<tr>
<td>Loss on disposal of assets</td>
<td>0.9</td>
<td>—</td>
</tr>
<tr>
<td>Transaction costs</td>
<td>0.2</td>
<td>—</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong> <em>(b)</em></td>
<td>$70.4</td>
<td>$57.7</td>
</tr>
</tbody>
</table>

*(a)* ITDA—Interest expense, taxes, depreciation and amortization expense.

<table>
<thead>
<tr>
<th>EBITDA:</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net cash provided by operating activities</td>
<td>$83.5</td>
<td>$59.5</td>
</tr>
<tr>
<td>Net changes in working capital balances</td>
<td>(15.0)</td>
<td>(0.6)</td>
</tr>
<tr>
<td>Loss on disposal of assets</td>
<td>(0.9)</td>
<td>—</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated EBITDA</td>
<td>(1.0)</td>
<td>(1.9)</td>
</tr>
<tr>
<td><strong>EBITDA</strong> <em>(b)</em></td>
<td>$66.6</td>
<td>$57.0</td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>2.7</td>
<td>0.7</td>
</tr>
<tr>
<td>Loss on disposal of assets</td>
<td>0.9</td>
<td>—</td>
</tr>
<tr>
<td>Transaction costs</td>
<td>0.2</td>
<td>—</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong> <em>(b)</em></td>
<td>$70.4</td>
<td>$57.7</td>
</tr>
</tbody>
</table>

*(b) For the definitions of EBITDA and Adjusted EBITDA and a reconciliation to their most directly comparable GAAP financial measures, please read “Summary—Non-GAAP Financial Measures.”
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**Fiscal Year Ended September 30, 2009 Compared to Fiscal Year Ended September 30, 2008**

The following table summarizes the consolidated income statement components for the fiscal years ended September 30, 2009 and 2008, respectively (in millions):

<table>
<thead>
<tr>
<th>Year Ended September 30</th>
<th>2009</th>
<th>2008</th>
<th>Change in Dollars</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue</td>
<td>$87.5</td>
<td>$82.7</td>
<td>$4.8</td>
<td>5.8%</td>
</tr>
<tr>
<td>Cost of services sold</td>
<td>17.8</td>
<td>12.4</td>
<td>5.4</td>
<td>43.5%</td>
</tr>
<tr>
<td>Gross profit</td>
<td>69.7</td>
<td>70.3</td>
<td>(0.6)</td>
<td>(0.9)%</td>
</tr>
<tr>
<td>Operating and administrative expenses</td>
<td>10.8</td>
<td>11.7</td>
<td>(0.9)</td>
<td>(7.7)%</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>29.2</td>
<td>24.5</td>
<td>4.7</td>
<td>19.2%</td>
</tr>
<tr>
<td>Gain on disposal of assets</td>
<td>—</td>
<td>1.9</td>
<td>(1.9)</td>
<td>*</td>
</tr>
<tr>
<td>Operating income</td>
<td>29.7</td>
<td>36.0</td>
<td>(6.3)</td>
<td>(17.5)%</td>
</tr>
<tr>
<td>Other income</td>
<td>—</td>
<td>0.8</td>
<td>(0.8)</td>
<td>*</td>
</tr>
<tr>
<td>Net income</td>
<td>29.7</td>
<td>36.8</td>
<td>(7.1)</td>
<td>(19.3)%</td>
</tr>
<tr>
<td>Net income attributable to non-controlling partners</td>
<td>1.4</td>
<td>1.4</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Net income attributable to member/partners</td>
<td>$28.3</td>
<td>$35.4</td>
<td>$(7.1)</td>
<td>(20.1)%</td>
</tr>
</tbody>
</table>

* Not meaningful

**Revenue**. Revenues in fiscal 2009 were $87.5 million, an increase of $4.8 million, or 5.8%, from $82.7 million in fiscal 2008.

Revenues from firm storage were $72.1 million in fiscal 2009, an increase of $4.5 million, or 6.7%, from $67.6 million in fiscal 2008. Natural gas firm storage revenues increased $2.6 million primarily due to the commencement of operations on the Stagecoach north lateral connecting to the Millennium Pipeline in December 2008. NGL revenues increased $1.9 million primarily due to an increase in contractual rates at our Bath NGL storage facility.

Revenues from transportation were $12.2 million in fiscal 2009, a decrease of $0.8 million, or 6.2%, from $13.0 million in fiscal 2008. This decrease was attributable to a both a decrease in rates and volumes.

Revenues from hub services were $3.2 million in fiscal 2009, an increase of $1.1 million, or 52.4%, from $2.1 million in fiscal 2008. This increase resulted from an increase in demand for interruptible services.

**Cost of Services Sold**. Cost of services sold for fiscal 2009 was $17.8 million, an increase of $5.4 million, or 43.5%, from $12.4 million in fiscal 2008.

Storage cost of services sold was $11.0 million, an increase of $8.0 million, or 266.7%, from $3.0 million in fiscal 2008. Natural gas storage cost of services increased $6.4 million primarily due an increase in compression cost at our Stagecoach facility. NGL cost of services increased $1.6 million primarily attributable to a decrease in fuel-in-kind collections and an increase in electricity costs. Fuel-in-kind collections during 2008 exceeded cost of services sold.

Transportation cost of services sold was $6.8 million in fiscal 2009, a decrease of $2.6 million, or 27.7%, from $9.4 million in fiscal 2008. This decrease was related to a decline in both volumes and rates on our firm transportation secured on a major pipeline.

Our storage cost of services sold consists primarily of direct costs to run the storage facilities, including electricity, contractor and fuel costs. Our transportation cost of services sold consists of our costs to procure firm
transportation capacity on certain pipelines. These costs are offset by any fuel-in-kind collections made during the period. Other costs incurred in conjunction with these services are included in operating and administrative expense and depreciation and amortization expense and consist primarily of depreciation, vehicle costs, including fuel, repair and maintenance costs, and wages. Depreciation expense for storage amounted to $26.1 million and $21.1 million for fiscal 2009 and 2008, respectively. Vehicle costs and wages amounted to $1.4 million and $1.9 million for fiscal 2009 and 2008, respectively. Because we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of services sold, our gross profit may not be comparable to other entities in our lines of business if they include these costs in cost of services sold.

Gross Profit. Gross profit for fiscal 2009 was $69.7 million, a decrease of $0.6 million, or 0.9%, from $70.3 million during fiscal 2008.

Storage gross profit was $64.3 million in fiscal 2009 compared to $66.7 million in fiscal 2008, a decrease of $2.4 million, or 3.6%. Natural gas storage gross profit decreased $2.7 million primarily attributable to an increase in compression costs at our Stagecoach facility. NGL gross profit increased $0.3 million due to an increase in contractual rates offset by a decline in fuel-in-kind collections. Storage gross profit consists of firm storage and hub services.

Transportation gross profit was $5.4 million in fiscal 2009, an increase of $1.8 million, or 50.0%, from $3.6 million in fiscal 2008. This increase resulted from an increase in market demand for the transportation capacity we secured on a major pipeline.

Operating and Administrative Expenses. Operating and administrative expenses were $10.8 million in fiscal 2009 compared to $11.7 million in fiscal 2008. This $0.9 million, or 7.7%, decrease in operating expenses was due primarily to a decrease in long-term incentive and equity compensation.

Depreciation and Amortization. Depreciation and amortization increased to $29.2 million in fiscal 2009 from $24.5 million in fiscal 2008. This $4.7 million, or 19.2%, increase was primarily the result of placing into service an expansion project at our Stagecoach facility.

Gain on Disposal of Assets. Gain on disposal of assets decreased $1.9 million in fiscal 2009. The gain recognized in fiscal 2008 was due to the sale of base gas at our Stagecoach facility. No such gain was recognized in fiscal 2009.

Net Income Attributable to Non-controlling Partners. We acquired a majority interest in the operations of Steuben Gas when we acquired 100% of the membership interest in ASC in October 2007. ASC held a majority interest in the operations of Steuben Gas until July 2010.

Net Income Attributable to Member/Partners. Net income for fiscal 2009 was $28.3 million compared to net income for fiscal 2008 of $35.4 million. The $7.1 million, or 20.1%, decrease in net income is primarily attributable to higher depreciation and amortization partially offset by lower operating expenses in fiscal 2009.
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EBITDA and Adjusted EBITDA. The following tables summarize EBITDA and Adjusted EBITDA for the fiscal years ended September 30, 2009 and 2008, respectively (in millions):

<table>
<thead>
<tr>
<th>Year Ended September 30</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
<td>2008</td>
</tr>
<tr>
<td>EBITDA:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net income attributable to member/partners</td>
<td>$28.3</td>
<td>$35.4</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated ITDA (a)</td>
<td>(0.5)</td>
<td>(0.8)</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>29.2</td>
<td>24.5</td>
</tr>
<tr>
<td><strong>EBITDA</strong> (a)</td>
<td><strong>$57.0</strong></td>
<td><strong>$59.1</strong></td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>0.7</td>
<td>0.5</td>
</tr>
<tr>
<td>(Gain) on disposal of assets</td>
<td>—</td>
<td>(1.9)</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong> (a)</td>
<td><strong>$57.7</strong></td>
<td><strong>$57.7</strong></td>
</tr>
</tbody>
</table>

(a) ITDA—Interest expense, taxes, depreciation and amortization expense.

<table>
<thead>
<tr>
<th>Year Ended September 30</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
<td>2008</td>
</tr>
<tr>
<td>EBITDA:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net cash provided by operating activities</td>
<td>$59.5</td>
<td>$62.9</td>
</tr>
<tr>
<td>Net changes in working capital balances</td>
<td>(0.6)</td>
<td>(3.5)</td>
</tr>
<tr>
<td>Gain on disposal of assets</td>
<td>—</td>
<td>1.9</td>
</tr>
<tr>
<td>Interest of non-controlling partners in consolidated EBITDA</td>
<td>(1.9)</td>
<td>(2.2)</td>
</tr>
<tr>
<td><strong>EBITDA</strong> (1)</td>
<td><strong>$57.0</strong></td>
<td><strong>$59.1</strong></td>
</tr>
<tr>
<td>Long-term incentive and equity compensation expense</td>
<td>0.7</td>
<td>0.5</td>
</tr>
<tr>
<td>(Gain) on disposal of assets</td>
<td>—</td>
<td>(1.9)</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong> (1)</td>
<td><strong>$57.7</strong></td>
<td><strong>$57.7</strong></td>
</tr>
</tbody>
</table>

(1) For the definitions of EBITDA and Adjusted EBITDA and a reconciliation to their most directly comparable GAAP financial measures, please read “Summary—Non-GAAP Financial Measures.”

Liquidity and Sources of Capital

Our operations, including capital expenditures and acquisitions, have historically been funded by NRGY. Our principal liquidity requirements are to finance current operations, fund capital expenditures, including acquisitions from time to time, and to service our debt. Subsequent to this offering, we expect our sources of liquidity from time to time to include cash generated from operations, borrowings under our revolving credit facility and issuances of debt and equity securities.

In connection with this offering, we will assume approximately $ million of indebtedness from NRGY under a $ million revolving credit facility that will be assigned to us of which we will repay $ million using net proceeds of this offering. We believe we will be able to fund up to the first $ of internal growth projects or potential acquisitions primarily through borrowings under our revolving credit facility or through other sources described above.

Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven primarily by changes in accounts receivable and accounts payable. Our historical working capital balances are not necessarily indicative of the expected working capital balances going forward as they are not expected to be impacted by the historical treasury management arrangements with NRGY.
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Historical Cash Flow Information


Net operating cash inflows were $65.2 million and $56.8 million for the nine-month periods ended June 30, 2011 and 2010, respectively. The $8.4 million increase in operating cash flows is primarily related to the commencement of Thomas Corners' storage contracts in April 2010.

Net investing cash outflows were $64.1 million and $38.4 million for the nine-month periods ended June 30, 2011 and 2010, respectively. Net cash outflows were primarily impacted by a $25.7 million increase in purchases of property, plant and equipment.

Net financing cash inflows (outflows) were $8.3 million and $(20.0) million for the nine-month periods ended June 30, 2011 and 2010, respectively. The net change was primarily impacted by a net borrowing from NRGY in 2011 of $8.3 million compared to a net payment to NRGY of $17.4 million in 2010. As described above, NRGY historically funded our working capital and growth capital expansion initiatives. We historically paid NRGY all cash generated from operations.

Fiscal Year Ended September 30, 2010 Compared to Fiscal Year Ended September 30, 2009

Net operating cash inflows were $83.5 million and $59.5 million for the fiscal years ended September 30, 2010 and 2009, respectively. The $24.0 million increase in operating cash flows is primarily related to the in-servicing of our Thomas Corners facility in November 2009 and lower compression costs at our Stagecoach facility.

Net investing cash outflows were $49.8 million and $74.1 million for the fiscal years ended September 30, 2010 and 2009, respectively. Net cash outflows were primarily impacted by a $24.6 million decrease in purchases of property, plant and equipment.

Net financing cash inflows (outflows) were $(37.3) million and $15.3 million for the fiscal years ended September 30, 2010 and 2009, respectively. The net change was primarily impacted by a net payment to a related party in 2010 of $28.4 million compared to a net borrowing from a related party of $18.5 million in 2009. As described above, NRGY historically funded our working capital and growth capital expansion initiatives. We historically paid NRGY all cash generated from operations.

Fiscal Year Ended September 30, 2009 Compared to Fiscal Year Ended September 30, 2008

Net operating cash inflows were $59.5 million and $62.9 million for fiscal years ended September 30, 2009 and 2008, respectively. The $3.4 million decrease in operating cash flow was attributable to a $7.1 million decrease in net income and a $2.9 million decrease in operating assets and liabilities offset by a $6.6 million increase in non-cash charges to net income.

Net investing cash outflows were $74.1 million and $108.9 million for the fiscal years ended September 30, 2009 and 2008, respectively. Net cash outflows were primarily impacted by a $36.0 million decrease in cash outlays related to acquisitions and a $20.0 million decrease in purchases of property, plant and equipment, partially offset by a $21.6 million decrease in proceeds from the sale of assets.

Net financing cash inflows were $15.3 million and $48.9 million for the fiscal years ended September 30, 2009 and 2008, respectively. The net change was primarily impacted by a $34.8 million equity contribution made by NRGY in the fiscal year ended September 30, 2008.

Distributions to Our Common Unitholders and IDR Holders

Our partnership agreement requires us to distribute 100% of our available cash each quarter to the holders of our common units, until each common unit has received the initial quarterly distribution. Generally, our available
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cash is defined as our cash on hand at the end of the quarter less the establishment of cash reserves. We do not have a legal
obligation to pay this distribution. Please read “Cash Distributions Policy and Restrictions on Distributions” and “Provisions of
Our Partnership Agreement Relating to Cash Distributions.”

Upon completion of this offering, our general partner will establish an initial quarterly distribution of $ per common unit
($ per common unit on an annualized basis) to the extent we have sufficient cash after establishment of reserves and payment
of fees and expenses, including payments to our general partner and its affiliates. For the first quarter that we are publicly traded,
we will pay investors in this offering a prorated distribution covering the period from the completion of this offering through
December 31, 2011, based on the actual length of that period. Our ability to pay the initial quarterly distribution is subject to
various restrictions and other factors described in more detail under the caption “Cash Distribution Policy and Restrictions on
Distributions.”

Our general partner will not be entitled to distributions on its non-economic general partner interest. NRGY currently holds
incentive distribution rights that entitle it to receive 50.0% of the cash we distribute from operating surplus in excess of the initial
quarterly distribution.

Capital Requirements

Our growth plans currently include the MARC I pipeline, the North/South expansion project, the development of NGL
We expect to fund our capital expenditures with a combination of cash generated from operations, borrowings under our revolving
credit facility and issuances of additional equity or debt.

Revolving Credit Facility

In connection with this offering, we will assume approximately $ million of indebtedness from NRGY under a $ million
revolving credit facility, with an expected maturity date five years from the closing of this offering, that will be assigned
to us of which we will repay $ million using net proceeds of this offering. We expect the revolving credit facility to be
available to fund working capital and our internal growth projects, make acquisitions and for general partnership purposes. We
expect to re-borrow $80 million under our revolving credit facility to fund a cash distribution to NRGY for reimbursement of
capital expenditures associated with our assets. As a result, we expect to have approximately $ million of remaining capacity
immediately after the closing of this offering, subject to compliance with any applicable covenants under such facility. We also
expect to have an accordion feature that would allow us to increase the available borrowings under the facility by up to $
 million, subject to the lenders agreeing to satisfy the increased commitment amounts under our new facility.

We expect our revolving credit facility will restrict our ability to, among other things:

- incur additional debt;
- make distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company; and
- transfer or otherwise dispose of assets.

Furthermore, our revolving credit facility will contain covenants requiring us to maintain certain financial ratios. We expect
that borrowings under our revolving credit facility will be secured by liens on substantially all of our assets and guaranteed by our
existing and future subsidiaries.
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**Potential Impact of Recent Economic and Financial Market Trends**

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic downturn. Worldwide financial markets have continued to be extremely volatile. The outlook for a worldwide economic recovery in 2011 remains uncertain, and we will not be unaffected by challenging economic and capital markets conditions if market conditions deteriorate or the worldwide recovery does not continue or continues at a slower rate. In particular, while we believe that cash flow in excess of distributions as well as borrowings under our revolving credit facility will enable us to fund our planned expansion activities for the next several years, funding of additional expansion activities or acquisitions may require us to access additional capital resources, which we intend to fund with a balanced combination of equity and debt capital. Although we believe that equity and debt markets will be available to us on reasonable terms based on current market conditions, there can be no assurance that future market conditions will permit us to access capital to fund future acquisition and expansion activities.

**Off-balance Sheet Arrangements**

We do not have any off-balance sheet arrangements.

**Contingencies**

For a discussion of contingencies that may impact us, please read (i) Note 7 to our audited consolidated financial statements as of September 30, 2009 and 2010 and for the fiscal years ended September 30, 2008, 2009 and 2010 that are included elsewhere in this prospectus and (ii) Note 4 to our unaudited consolidated financial statements as of June 30, 2011 and for the nine months ended June 30, 2010 and 2011 that are included elsewhere in this prospectus.

**Contractual Obligations**

Our growth projects require us to enter into certain purchase commitments with certain vendors.

The following table summarizes our contractual obligations as of September 30, 2010 (in millions):

<table>
<thead>
<tr>
<th>Purchase commitments of identified growth projects (a)</th>
<th>Total</th>
<th>Less than 1 year</th>
<th>1-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchase commitments of identified growth projects (a)</td>
<td>$12.3</td>
<td>$12.3</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Total contractual obligations</td>
<td>$12.3</td>
<td>$12.3</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
</tr>
</tbody>
</table>

(a) Identified growth projects related to our MARC I pipeline, North/South expansion project and Watkins Glen NGL facility.

**Quantitative and Qualitative Disclosures About Market Risk**

From time to time, we may use derivative instruments to (i) manage our exposure to interest rates or natural gas prices associated with future base gas purchases and (ii) economically hedge the intrinsic value of our natural gas storage facilities.

**Commodity Price Risk**

We do not take title to the natural gas or NGLs that we store or transport for our customers and, accordingly, are not exposed to commodity price fluctuations on natural gas or NGLs stored in our facilities or transported through our pipelines by our customers. Except for the base gas we purchase and use in our natural gas storage facilities, which we consider to be a long-term asset, and volume and pricing variations related to small volumes of fuel-in-kind natural gas that we are entitled to retain from our customers as compensation for our fuel costs,
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our current business model is designed to minimize our exposure to fluctuations in commodity prices. As a result, absent other market factors that could adversely impact our operations, changes in the price of natural gas or NGLs should not materially impact our operations. NRGY has not historically engaged in material commodity hedging activities relating to the assets comprising our business. However, we may engage in commodity hedging activities in the future, particularly if we undertake growth projects or engage in acquisitions that expose us to direct commodity price risk.

**Interest Rate Risk**

Our operating and acquisition activities have historically been funded by NRGY. Interest has not historically been charged in the funding of these activities.

As described above, in connection with this offering, we expect to assume from NRGY a $ million revolving credit facility. We may or may not hedge portions of our borrowings under the revolving credit facility from time to time.

**Recent Accounting Pronouncements**

FASB Accounting Standards Codification Subtopic 810-10 ("Subtopic 810-10"), originally issued as SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements—an amendment of ARB No. 51", was issued in December 2007 and requires that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Subtopic 810-10 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. Subtopic 810-10 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. We adopted Subtopic 810-10 on October 1, 2009. The adoption of Subtopic 810-10 did not have a material impact on our results of operations or financial position.

**Critical Accounting Policies**

*Revenue Recognition.* Revenue from storage and transportation contracts is recognized during the period in which the related services are provided.

*Impairment of Goodwill and Long-Lived Assets.* Goodwill is subject to at least an annual assessment for impairment by applying a fair-value-based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer's intent to do so.

We completed the valuation of each of our reporting units and determined no impairment existed as of September 30, 2010. The valuation of our reporting units requires us to make certain assumptions as it relates to future operating performance. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. If the growth assumptions embodied in the current year impairment testing prove inaccurate, we could incur an impairment charge. A 10% decrease in the estimated future cash flows and a 1% increase in the discount rate used in our impairment analysis would not have indicated a potential impairment of any of our intangible assets. To date, we have not recognized any impairment on assets we have acquired.

*Accruals and Contingent Liabilities.* Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Such accruals may include estimates and are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory requirements for operating gas storage.
facilities, costs of medical care associated with worker’s compensation and employee health insurance claims, and the possibility of legal claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. Presently, there are no material accruals in these areas. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Seasonality

Because a high percentage of our baseline cash flow is derived from fixed reservation fees under multi-year contracts, our revenues are not generally seasonal in nature, nor are they typically affected by weather and price volatility during the term of the multi-year contracts. Weather impacts natural gas demand for power generation and heating purposes and propane demand for heating purposes, which in turn influences the value of storage across our natural gas and NGL facilities. Peak demand for natural gas typically occurs during the winter months, caused by the heating load, although certain markets such as the Florida market peak in the summer months due to cooling demands. Peak demand for propane typically occurs during the winter months, caused by residential heating load.
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NATURAL GAS INDUSTRY

The midstream sector of the natural gas industry provides the link between the exploration and production of natural gas and the delivery of natural gas and its components to end-use markets. The midstream sector consists generally of gathering and processing, transportation and storage activities. Our midstream operations currently focus on transportation and storage activities, for both natural gas and NGLs.

The natural gas pipeline grid transports natural gas from producing regions to customers, such as LDCs, electric generation facilities and industrial users. Interstate pipelines carry natural gas across state boundaries and are subject to FERC regulation on (i) the rates charged for their services, (ii) the terms and conditions of their services, and (iii) the location, construction and abandonment of their facilities. Intrastate pipelines transport natural gas within a particular state and are customarily not subject to FERC regulation.

Natural gas storage plays a vital role in maintaining the reliability of natural gas supplies needed to meet the demands of consumers. Storage facilities are utilized by pipelines to balance operations, by natural gas end users such as LDCs to manage volatility and secure natural gas supplies, and by independent natural gas marketing and trading companies in connection with the execution of their trading strategies. Storage allows for the warehousing of natural gas and is used to inject excess production during periods of low demand (typically warmer months) and to withdraw natural gas during periods of high demand (typically colder winter months). The diagram below illustrates the position and function of natural gas storage and transportation within the natural gas market chain.

Market Fundamentals

Natural Gas Demand

Natural gas is a significant component of energy consumption in the United States. According to the U.S. Energy Information Administration, or EIA, natural gas consumption accounted for approximately 24% of all energy used in the United States in 2010, representing 24 Tcf of natural gas. The EIA estimates that over the next 27 years, total domestic energy consumption will increase by over 15%, with natural gas consumption directly benefiting from population growth, growth in cleaner-burning natural gas-fired electric generation and natural gas vehicles.

Within the U.S. market, natural gas is primarily used as a fuel source for heating and cooking within the residential and commercial sectors (37%), electric generation (33%) and industrial markets (30%). Approximately 23% of the electricity generated in the United States is fueled by natural gas, while coal (45%), nuclear (20%) and other fuels (12%) comprise the remaining fuel sources. These market shares are reflected in the graphs below.
According to the EIA, as shown in the chart below, during the period from 2001 through 2010, natural gas consumption increased by 8.5% overall from an average of approximately 60.9 Bcf/d in 2001 to an average of approximately 66.1 Bcf/d in 2010. Although the change in consumption levels during this period was variable on a year-to-year basis, growth was highest in the seasonal and weather-sensitive electric power generation and commercial/residential sectors, where consumption grew by approximately 38.1% and 4.7%, respectively. The growth in these sectors was partially offset by an approximate 10.1% decline in natural gas consumption in the less seasonal industrial sector.

Source: EIA, U.S. Natural Gas Consumption by End Use (June 2011) and Electric Power Annual 2009.

Forecasts published by the EIA and other industry sources anticipate that long-term demand for natural gas will continue to grow, and that the historical trend of growth in natural gas demand from seasonal and weather-sensitive consumption sectors will continue. These forecasts are supported by various factors, including (i) expectations of continued growth in the U.S. gross domestic product, which has a significant influence on long-term growth in natural gas demand; (ii) an increased likelihood that regulatory and legislative initiatives regarding domestic carbon policy will drive greater demand for cleaner burning fuels like natural gas;

Source: EIA, U.S. Natural Gas Consumption by End Use (June 2011).
(iii) increased acceptance of the view that natural gas is a clean and abundant domestic fuel source that can lead to greater energy independence for the United States by reducing its dependence on imported petroleum; (iv) the emergence of low-cost natural gas shale developments, which suggest ample supplies and which are expected to keep natural gas prices relatively low relative to crude oil prices, making the commodity attractive as a feedstock; and (v) continued growth in electricity generation from intermittent renewable energy sources, primarily wind and solar energy, for which natural-gas fired generation is a logical back-up power supply source. According to the EIA, natural gas consumption is expected to rise from 22.7 Tcf in 2009 to 26.5 Tcf in 2035.

**Natural Gas Supply**

Domestic natural gas consumption is today satisfied primarily by production from conventional onshore and offshore production in the lower 48 states, as supplemented by production from historically declining pipeline imports from Canada, imports of LNG from foreign sources, and some Alaska production. In order to maintain current levels of U.S. natural gas supply and to meet the projected increase in demand, new sources of domestic natural gas must continue to be developed to offset an established trend of depletion associated with mature, conventional production as well as the uncertainty of future LNG imports and infrastructure challenges associated with sourcing additional production from Alaska. Over the past several years, a fundamental shift in production has emerged with the contribution of natural gas from unconventional resources (defined by the EIA as natural gas produced from shale formations and coalbeds) increasing from 6% of total U.S. natural gas supply in 2000 to 16% in 2008. In fact, according to EIA data, during the three-year period from January 15, 2007 through December 15, 2010 domestic production of natural gas increased by an average of approximately 4% per annum, largely due to continued development of shale resources. The emergence of shale plays has resulted primarily from advances in horizontal drilling and hydraulic fracturing technologies, which have allowed producers to extract significant volumes of natural gas from these plays at cost-advantaged per unit economics versus most conventional plays.

The U.S. Geological Service, Mineral Management Service and EIA estimated that in 2010 the United States possessed over 2,600 Tcf of technically recoverable natural gas resources, an increase of approximately 30% from 2008 estimates of technically recoverable natural gas resources, which is primarily due to technological advancements. As the depletion of onshore conventional and offshore resources continues, natural gas from unconventional resource plays is forecast to fill the void and continue to gain market share from higher-cost sources of natural gas. Natural gas production from the major shale formations is forecast to provide the majority of the growth in unconventional natural gas supply, increasing to approximately 47% of total U.S. natural gas supply in 2035 as compared with 16% in 2009.

![Natural Gas Production by Source, 1990-2035 (Tcf)](image_url)

Market Imbalances

The fundamentals of the natural gas market create a basic demand for storage. Natural gas is produced at a relatively steady rate throughout the year so natural gas supply is relatively constant. However, natural gas consumption is highly seasonal because the market consumes more natural gas in the winter than can be produced. In contrast, more natural gas is produced in the summer than is consumed, which creates this fundamental need for storage. Natural gas storage acts as the balancing mechanism between supply and demand.

Historical Natural Gas Supply and Demand

Source: Derived from EIA, U.S. Natural Gas Summary (June 29, 2011).

Natural Gas Storage Industry

Natural gas is typically stored underground in depleted reservoirs, aquifers or salt caverns. Underground storage facilities contain what is known as base gas, or cushion gas, which is the volume of natural gas that is injected into the facility to maintain adequate pressure and deliverability rates, especially throughout the withdrawal season. In general, working gas is the volume of natural gas in a storage facility at a given point in time that exceeds the amount of base gas. Assuming adequate operating pressures, working gas is the amount of natural gas that can be extracted during the facility’s normal operation. References to the capacity of a storage facility typically refer to its working gas capacity.

Aquifers are underground rock formations that act as natural water reservoirs. Aquifers are typically found in regions without depleted oil and natural gas reservoirs. Based on publicly available information, we estimate that depleted reservoirs comprise approximately 85% of total working gas storage capacity in the United States. Depleted reservoir facilities are prevalent in the producing regions of the United States. Most salt cavern facilities have been developed in salt dome formations located along the Gulf Coast, with more limited development in bedded salt formations located in northeastern, midwestern and southwestern states. Our natural gas storage facilities are depleted reservoir or salt cavern storage facilities.
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The following charts provide an overview of the depleted reservoir and salt cavern storage facilities:

Key Characteristics of Storage Facilities

- **Capacity**: References to the capacity of a storage facility typically refer to its working gas capacity, the amount of natural gas that can be extracted during the facility’s normal operation. The ability to expand a facility to increase its storage capacity is also an important characteristic.

- **Injection and Withdrawal Capabilities**: A distinguishing operational characteristic of any given storage facility is its peak injection and withdrawal rate, which dictates the number of times during a given year that a facility is capable of being “turned” or “cycled” (i.e., completely filled with injections of working gas and then completely emptied of working gas by withdrawals) and its connectivity to different pipelines and/or markets. Higher peak injection and withdrawal rates and access to multiple markets provide storage users with greater commercial and operational flexibility and, accordingly, command higher storage rates. Salt caverns are cavities or chambers formed in underground salt deposits, and natural gas can be freely injected into and withdrawn from such caverns with the aid of compression. Conversely, depleted reservoirs store natural gas within porous rock formations and the ability of natural gas to move into and out of the facility is limited by the permeability of the applicable formations, even with the aid of compression. As a result, salt caverns generally have significantly higher peak injection and withdrawal rates, and can be cycled more times per year, than depleted reservoirs and aquifers.

- **Connectivity to Pipelines and Markets**: Storage facilities that are directly or indirectly connected to multiple transmission pipelines offer significant value to the storage capacity holder by providing flexible and timely access to consuming markets.

- **Cost to Develop**: The primary categories of cost associated with the development of natural gas storage facilities are (i) real and personal property acquisition costs, (ii) equipment purchase costs, (iii) costs associated with construction, and (iv) the cost of acquiring base gas, which is required to maintain operating pressures and allow for working gas withdrawals. With respect to construction and other non-base gas costs, depleted reservoir facilities are usually the least expensive to develop as portions of existing pipeline and facility infrastructure related to prior production operations can often be used in connection with the development and operation of a depleted reservoir facility, reducing up-front infrastructure costs. In terms of base gas costs, which represent an additional up-front investment cost for a storage facility operator, according to a FERC report on underground natural gas storage, salt caverns typically require the lowest levels of base gas at approximately 20-30% of total natural gas capacity. By comparison, depleted reservoirs typically require approximately 50% base gas.

- **Geological Risks**: A critical attribute of any underground natural gas storage facility is the integrity of the geological structure in which the natural gas is stored. The geology of depleted reservoirs is typically well understood and the risk of natural gas leaks is relatively low given their prior natural use for storing hydrocarbons. The risk of natural gas leaks from salt caverns is also relatively low given that the walls of a properly constructed salt cavern provide a non-porous seal that reduces the likelihood of natural gas leaks.
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Competition and Barriers to Entry

Storage operators compete for customers based on geographical location, which determines connectivity to pipelines and proximity to supply sources and end-users, as well as operating reliability and flexibility, price, available capacity and service offerings. From the storage operator’s perspective, having a diverse customer group that requires a variety of storage services is important to maximizing asset utilization and capturing incremental revenue opportunities while minimizing costs.

Although competition within the storage industry is robust, there are significant barriers to entering the natural gas storage business. These barriers include, among others:

- **Costs and Execution Risk**. The costs of developing and constructing an underground storage facility are significant and highly variable, depending on drilling costs, subsurface issues, raw water availability, brine disposal arrangements, compression requirements, costs of establishing interconnects and other factors. The creation of storage facilities also involves significant execution risk with respect to drilling and completing wells and related sub-surface activities.

- **Time Commitment**. The length of time required to permit and develop a new project and place it into service can be long and unpredictable, generally ranging from two to four years or more, depending on the type of facility, location, permitting issues, subsurface issues and other factors.

- **Financing**. The magnitude and uncertainty of capital costs, length of the permitting and development cycle and scheduling uncertainties associated with natural gas storage development can present significant project financing challenges.

- **Limited Number of Sites**. Finding and developing new natural gas storage facilities, or acquiring existing facilities, is extremely competitive given that there are a limited number of sites that possess the requisite characteristics in terms of proximity to pipelines and load centers, operational flexibility, geological characteristics and overall risk/return profile.

- **Required Expertise**. Specialized expertise is required to identify market areas that require or will support additional storage capacity. In addition, acquiring, developing and operating natural gas storage facilities involves identifying, assessing and managing significant geological and other risks that require specialized industry knowledge and experience, including in the areas of reservoir engineering and geology, cavern or reservoir development and construction, and natural gas compression, handling, treating and transportation. Individuals with significant relationships with customers and other participants across the natural gas supply chain are also invaluable in providing a commercial understanding of the natural gas market. Because there is significant market demand for this combination of skill sets and individuals with such skill sets are in short supply, finding and retaining management and operational personnel is highly competitive.

Value Drivers for Natural Gas Storage

The long-term demand for storage services in the United States is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as natural gas-fired electric generators), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and value of storage services.

In terms of valuing storage demand, the principal value drivers include:

- **Location**. The location of storage is a key value component for natural gas storage facilities. Storage assets that are closer in proximity to markets that generate more demand relative to local supplies are
generally more valuable than are storage assets located in closer proximity to supply hubs. For purposes of tracking
natural gas storage levels, the American Gas Association, or AGA, divides the contiguous United States into three
regions: the Eastern Consuming region, the Producing region and the Western Consuming region. According to the
EIA, during the period from January 1, 2005 to July 28, 2011, average daily natural gas consumption in the AGA
Eastern Consuming region was approximately 12.9 Bcf/d compared to average daily production in that region of
approximately 1.8 Bcf/d. This shortfall in supply can be more pronounced in the winter months during periods of peak
demand. Additionally, storage assets that have more access to takeaway capacity, and therefore better market access,
also tend to have higher value.

- **Volatility of Natural Gas Prices.** In times when natural gas prices are more volatile, the value of storage capacity
increases because storage capacity holders with the contractual ability to withdraw or inject natural gas, as applicable,
are able to capture more value from their storage capacity. When near-term natural gas prices are volatile, storage
capacity holders often have opportunities to inject and withdraw natural gas from storage in an effort to earn
incremental margins above the seasonal spread as market opportunities permit. This is sometimes referred to as the
option value of natural gas storage. In addition, increased volatility in demand can intensify the demand for storage for
supply reliability. Natural gas storage facilities with higher injection and withdrawal capabilities are best able to capture
value from natural gas market volatility.

- **Operating Flexibility.** Each type of storage facility (depleted reservoir or salt cavern, for example) offers a different
type of operational flexibility. The number of times that natural gas can be “turned,” or injected and withdrawn, in a
single year is a significant component of storage asset value. Connectivity of a storage facility to multiple transportation
pipelines with downstream access to demand markets is also a significant component of storage asset value.

- **Seasonal Spreads.** This spread is the difference between the highest and lowest natural gas prices on the NYMEX
12-month forward curve, less the carrying costs of storage. Natural gas storage capacity allows the capacity holder to
take advantage of the seasonal spread by injecting and storing natural gas when prices are low and then withdrawing
the natural gas during periods of high demand when prices are higher. The gross margin available from buying and
injecting natural gas in summer months for withdrawal in winter months can be locked in at the time of injection by
entering into a forward sale for the natural gas.

- **Service Reliability.** The ability to provide service that is in line with both contract terms and customer expectations is a
value driver. Customers are generally less inclined to enter into or renew agreements with storage providers who
frequently experience operational problems, or otherwise have difficulty providing storage services upon mutually-
agreed terms and conditions.

**NGL Industry Dynamics**

Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically
contains higher concentrations of NGLs than natural gas produced from natural gas wells. Unprocessed natural gas containing
NGLs is generally not acceptable for transportation in the U.S. interstate pipeline system or for commercial use. Processing plants
extract the NGLs, leaving residual dry gas that meets interstate pipeline and commercial quality specifications. Furthermore,
processing plants produce NGLs which, on an energy equivalent basis, usually have a greater economic value as a raw material
for petrochemicals, motor gasolines or commercial use than as a residual component of the natural gas stream. In order for the
mixed NGLs to become marketable to end users, they are first fractionated into NGL products, sometimes put into storage and
ultimately distributed to end users.

We believe that current industry dynamics are resulting in increases in domestic drilling targeting NGLs, particularly in areas
with unconventional reserves, creating the need for additional NGL infrastructure and services. Factors contributing to this
include (i) a strong crude oil and NGL price environment relative to current
natural gas prices, with the price of West Texas Intermediate crude oil at $82.26/bbl, Henry Hub spot prices for natural gas at $3.99/MMBtu and composite NGL prices at $1.34/gallon as of August 19, 2011; (ii) the continuation of oil and natural gas exploration and production innovation including geophysical interpretation, horizontal drilling and well completion techniques; (iii) a trend toward increased drilling in oil, condensate and NGL rich, or "liquids rich" reservoirs, especially resource plays; and (iv) increasing levels of supply of mixed NGLs coupled with strong demand from petrochemical complexes and exports which are leading to higher capacity utilization of NGL storage facilities. We believe these trends will continue to result in strong demand for the services provided by our NGL storage business.