Planning for the Future:

Today’s Urgent Need for an Integrated Approach

November 2016

Field Development Plan - Duvernay Case Study

Abstract

The development of new unconventional gas plays and the reinvigoration of existing plays will cautiously proceed in today’s lower price environment with the focus on maintaining cash flow with accompanying improvements in productivity, recovery and efficiency.

Unconventional reservoirs present unique challenges, and as new plays are delineated, uncertainty in future production performance must be addressed. Reservoir uncertainty has a significant impact on the success of a new project as there is often a need to make large infrastructure capital and egress commitments before that uncertainty can be reduced.

In addition, it is no longer sufficient for producing companies to focus its efforts solely on reservoir deliverability and production targets. Traditional markets for natural gas and NGL's have changed fundamentally. Access to these markets product at prices sufficient to cover costs is equally challenging. Infrastructure development for unconventional plays requires an increased and integrated focus as it represents a significant portion of the expected life cycle costs to bring the production to market.

These three elements; reservoir, midstream and market egress; reach across the energy value chain. They are interdependent and must be simultaneously understood and optimized. Success will come to producing companies that excel in this process. A well thought out field development plan (“FDP”) addressing these elements in an integrated manner is needed as is presented in Figure 1.

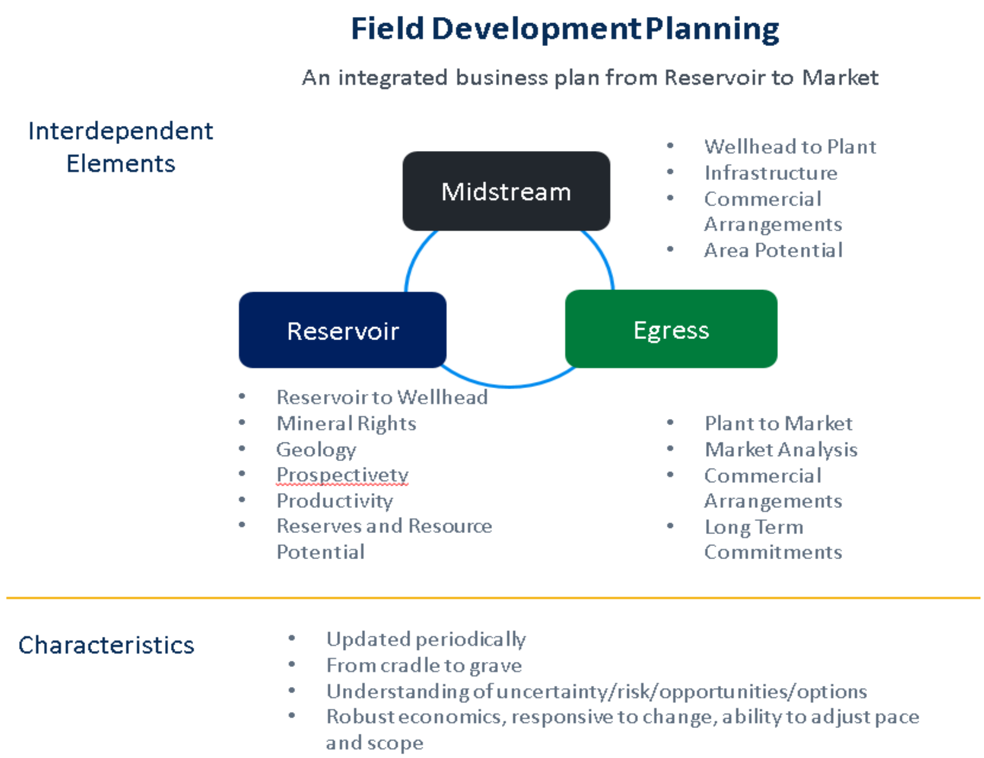

Figure 1: Field development planning ("FDP") components

Summary

This paper illustrates the benefits of the FDP process using development scenarios for the Duvernay Formation (Duvernay) in the Kaybob area of Alberta, Canada This Duvernay FDP case study compares the economic results of a defined project under several development, infrastructure and market egress strategies. While by no means exhaustive, it highlights the risks and rewards attributable to each of the three elements.

The FDP case study also highlights the risks and uncertainties that must be taken into account in its development. Risks are measureable events and can be predicted/reduced/mitigated. Uncertainties however, are uncontrollable although we may be reasonably confident in bracketing the range of likely outcomes. Examples of the latter include price forecasts, reservoir performance, and availability of interruptible egress capacity.The FDP needs to explicitly recognize the risks and probable range of uncertainties in choosing the optimal development scenario. These uncertainties should not be ignored or assumed to be immaterial; e.g. basing the FDP on a single production or price forecast; but explicitly recognized.

The Duvernay play is nearing the end of the delineation and discovery phase, and operators are moving into the commercial production phase. The development of the play is challenging in today's lower price environment due to the complexity of the reservoir (in

terms of productivity and the targeted high liquid composition), the high cost to drill and complete these wells, the potential for sour gas, and the resultant complexity of the required production equipment, collection and processing and egress infrastructure.

Why an Integrated Approach

Within many organizations, the upstream, midstream and marketing operations are often handled by different groups within an organization with greater emphasis being placed on one aspect while others are addressed superficially or not at all.

The advent of horizontal multi-stage fractured well technologies has dramatically increased the resource potential throughout North America. Many producers have successfully added massive reserves within their portfolios. Development of these reserves often high capital costs accompanied by high uncertainty with respect to their productivity. A company successful at managing these upstream challenges is rewarded with resource large inventory of economic drilling opportunities and the potential for high sustained field production rates. Many companies have been successful in achieving this.

Unfortunately, access to large hydrocarbon resources does not necessarily guarantee success. A producing company must also have thought through the ability to ensure long term profitable access to the infrastructure necessary to process these reserves and to the markets for the produced hydrocarbon products; all of this occurring within a backdrop of a host of factors such as uncertain product prices, area reserves and resource estimate uncertainty, competition from other producers, uncertainty of available egress options, complex commercial arrangements with key buyers of products and providers of services, and impacts from regulatory and other external factors etc.

Because of these challenges, resource rich companies often struggle to get sufficient product volumes to market at the prices needed to generate the returns required to profitably fund the large capital expenditures. There are many examples of companies with desirable oil and gas assets who have been unable to optimally develop and grow, or even survive, due to poor infrastructure and egress planning.

Duvernay Study Area

The Duvernay is of late Devonian age and consists of dark brown bituminous shales and limestone which were deposited as a basin filling equivalent to the rising Leduc reefs. It is a thermogenic system and major source rock for the conventional hydrocarbon reservoirs of the Upper Devonian in Alberta. Apart from being a source rock, the Duvernay can act as a seal and a reservoir for hydrocarbons. Oil and gas are stored in available free porosity and fractures, as well as adsorbed to organic matter. The Duvernay is usually calcareous and, proximal to the Leduc reefs, the carbonate component generally increases. The formation is overlain conformably by the Ireton shale and underlain by either the Majeau Lake shales or the Cooking Lake carbonates.

In the Kaybob area, the formation is approximately 50m thick, with an average effective porosity of seven percent and a TOC content ranging from one percent to four percent.

The Duvernay was discovered in the 1950's but there was minimal development occurred prior to 2012, when horizontal multi-staged fractured well technology began to be used to extract hydrocarbons from this play.

For this study, a 48 section area in the Duvernay trend was selected for analysis. This area is within the Kaybob region, in the northern portion of the Duvernay trend. Several hundred wells have been drilled in this region by early 2016, and operators are in the process of transitioning from delineation and assessment to commercial production of their assets.

Figure 2 presents a map which identifies the three liquid yield regions of the evaluated area and existing infrastructure. While this study does not attempt to provide an analysis of any specific company in this trend, the methodology used in this study can be used for any company in any of the resource plays being developed, with specific parameters modified for those specific projects.

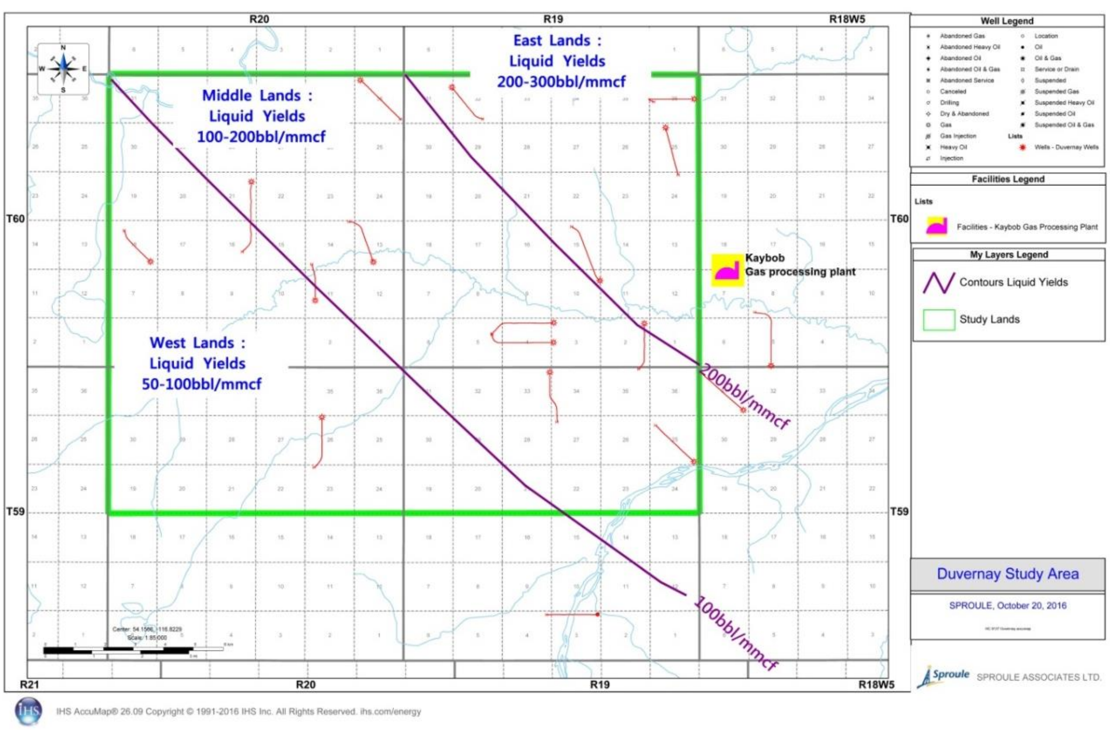

Figure 2: Kaybob Duvernay Study area

Key Assumptions

This case study uses several assumptions to simply the analysis, including:

- This is a core asset of the company, and ranks high within the corporate portfolio.
- The company owns an average of 50% working interest across this property.
- Due to terrain restrictions, 75% of the land base can be developed.
- The gas is potentially sour. While there is midstream infrastructure in the area, it is not sufficient to fully develop the assets. Assumed typical dew-point refrigeration processing.
- An effective date of January 1, 2016, using the Sproule December 31, 2015 price forecast
- The company has access to the capital required to develop the assets.
- Development will occur offsetting the company's lands by competing companies. There is an opportunity to cooperate with other companies on gaining access to gathering and processing infrastructure. Processing infrastructure includes the capability for acid gas injection.
- Capital cost estimates for drill and complete (D&C) are based on Sproule and GPMi's experience in the Duvernay.
- Capital and operating costs for well tie-ins, gathering systems, artificial lift (gas lift and compression), and processing are based on industry Sproule and GPMi's industry experience and knowledge.
- Both firm and interruptible provisions are considered for product egress based on known conditions for egress from the study area.
- An estimate was provided for end of life abandonment on a per well basis.
- An estimate for the announced Alberta carbon taxes coming into play in 2017 was included assuming the operator is considered a large emitter.

Well Performance

Modelling Assumptions

A robust field development plan begins with a rigorous reservoir performance analysis. Plays are not homogeneous, and the performance characteristics of the area being evaluated must be well understood. This evaluation starts with an understanding of the rock and fluid properties. In this study, a liquid yield gradient was observed. Well performance is impacted by the varying liquid yields, so a single set of type curves cannot be used across this study area. The evaluated area was divided into three sub-regions based on expected liquid yields, and a set of type curves was developed for each liquid yield region. These regions are:

- 50-100 bbl/mmcf
- 100-200 bbl/mmcf
- 200-300 bbl/mmcf

This play has not yet been fully commercialized, and there is a significant amount of uncertainty regarding the future production performance and fluid composition in this area. For each of the three liquid yield regions, type curves were developed representing Low, Best ("Most Likely"), and High cases, which incorporates a full field development scenario. The spread between the Low and High cases is smaller than that of a single well development, due to the aggregation of the wells decreasing the overall project uncertainty. These scenarios provide a range of potential outcomes for the field that could be expected. Figures 3 through 5 present the type curve performance curves for the three liquid yield regions.

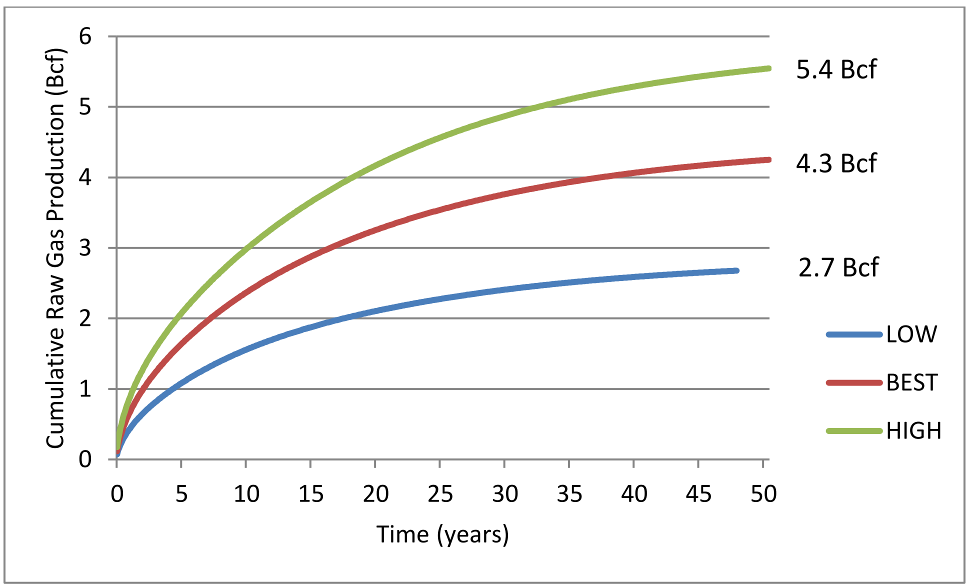

Figure 3: Type curve forecast for 50-100 bbl/mmcf yield region

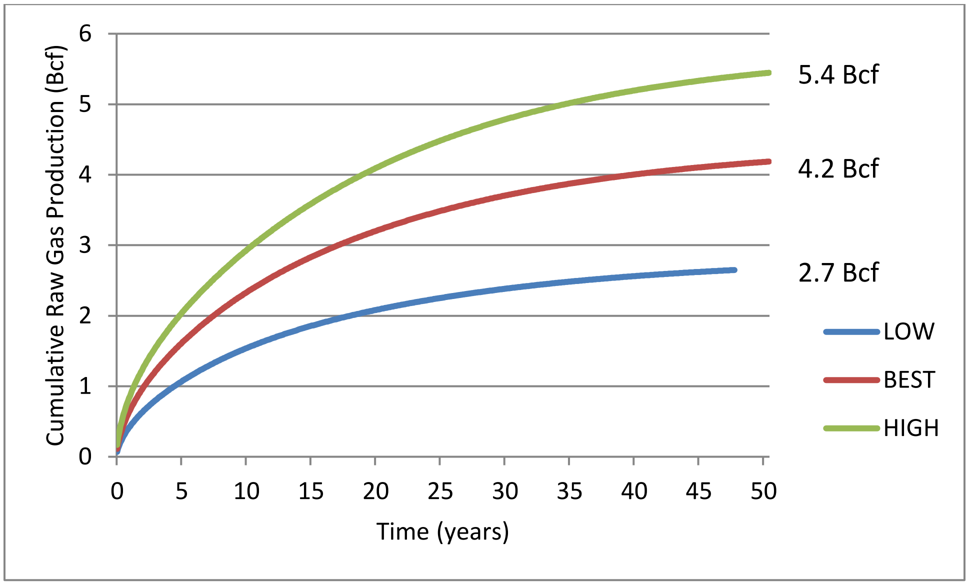

Figure 4: Type curve forecast for 100-200 bbl/mmcf yield region

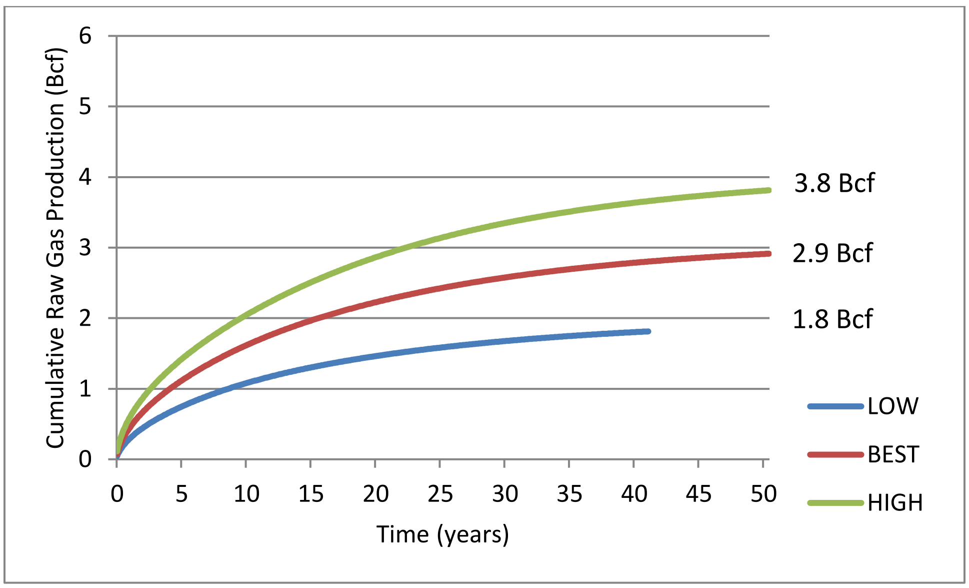

Figure 5: Type curve forecast for 200-300 bbl/mmcf yield region

Within the evaluated area approximately 60 wells are planned for the 50-100 bbl/mmcf region, 95 wells are planned for the 100-200 bbl/mmcf region, and 50 wells are planned for the 20-300 bbl/mmcf region.

The drilling program is adjusted for each scenario to model the different midstream capacities. All planned wells are assumed to be developed, and all required capital and drill/completion services are available.

Risks and Opportunities

With any emerging play, uncertainty exists both with respect to the reservoir characteristics as well as the drill and completion technology advances over time. For the purpose of this study, the producing wells in the study area are assumed to represent the average production performance in each region, and the reservoir within each liquid yield region is assumed to be relatively homogeneous. There is potential that there are areas of lower productivity reservoir within the study area, or that there are higher productivity "sweet spots" within the reservoir. A detailed risk assessment statistical analysis could be performed to further bracket this uncertainty. As future wells are drilled, their production performance should be incorporated into the type curve analysis. The type curve analysis should be updated regularly to ensure that the field production performance assumptions are still valid.

Over time, drill and completion technology may change within a play, as operators aim to optimize production and reduce costs. For the purpose of this study, future drill and completion technology is assumed to be the same as the current technology. Upside potential for technology changes could be incorporated in a FDP, which would expand the bracket of potential outcomes.

Midstream Infrastructure

Modelling Assumptions

The case study incorporates a typical representation of the midstream infrastructure from the well head to output of the processing plants. There are two main components:

1. Wellhead to Field nodes – An average of six wells are drilled on each well pad. Each well pad allows for three phase separation and temporary fractionation water storage. Inlets for fuel gas and gas lift gas for artificial lift, and fractionation water are incorporated. Outlet pipe incorporates three phase flow to centralized field nodes (six well pads on average connected to each node) as well as an outlet pipe for recovered fractionation water. Fractionation water is assumed to be provided from a centralized source for water treatment and makeup for a fee.

2. Field nodes to a gas processing plant – Field nodes are designed to allow compression, three phase separation and measurement and liquids and water storage. Liquids and gas are then transported separately along main gathering trunk lines to processing plants.

Gas processing plants include facilities for inlet compression, condensate stabilization, sweetening and acid gas injection, dew point refrigeration and liquid storage as well as compression to send fuel gas and artificial lift gas back to each well pad.

Capital costs were estimated using kpi's derived from a large sample of similar projects based on the predicted range (High to Low) of expected gas volumes and compositions.

Risks and Opportunities

There are several options for the design and building of infrastructure. Historically, producers with assets in developing plays in Western Canada have, to the extent possible, owned and controlled their own infrastructure. This is especially true near the wellhead and in the early stages of development. Generally, the further from the wellhead the hydrocarbons flow, and especially downstream of a processing plant, economies of scale outweigh the advantages of owning and controlling infrastructure.

However, there is a cost to owning infrastructure, if only for the capital required; capital that could perhaps be better spent on land and drilling or capital that may not be available to the producing company. Further, if every company blindly followed this path in the extreme, there would be an enormous redundancy of competing infrastructure.

Other considerations, besides capital availability, can influence decisions on infrastructure requirements. These include such items as:

- Production profile uncertainty and confidence with respect to type curve development, fluid composition, and ultimate recoverable volume. Is there enough confidence in future deliverability to commit capital to develop infrastructure? At what point does a producer commit to long lead time infrastructure projects, knowing that there will always be production performance uncertainty?
- Competitive advantage & control – Does owning infrastructure provide advantages for process optimization and product egress out of a competitive area? Building new highly automated, efficient and standardized infrastructure that is expected to be highly utilized through its useful life can offer large competitive cost advantages to a producer. However, there is risk and uncertainty associated with designing the right infrastructure for the right gas volumes and compositions over time.
- Joint venture options may be considered. Risks inherent in a producer building its own infrastructure can be reduced by collectively owning infrastructure with other producers. Joint ventures can reduce redundancy and allow economies of scale to be taken advantage of. A producer could either have others supply production to your facility for a processing fee or vice versa. This can be especially useful early on in a field's development when reservoir uncertainty is greatest; i.e. using a 3rd party's

facility and paying a processing fee through a piloting stage until there is less well productivity uncertainty. Joint ventures can also be useful as a longer term strategy. Having mutually advantageous commercial arrangements in place is key to making joint ventures successful. There are several ways in which these commercial terms can be structured.

- Area development plans must be considered. What are other producers planning to do in the area? How might these plans affect the ability of any one producer to build its own infrastructure and/or access other 3rd party infrastructure in the area? How cooperative are producers in the area?
- The potential for excess or insufficient capacity exists. There are economies of scale inherent in building larger facilities upfront. However, this approach can be a poor use of capital if the facility is highly under-utilized most of its life. These costs are further increased if the design is inappropriate for the gas composition or in allowing for changing market conditions; e.g. the ability to increase or decrease liquid recoveries. Modular design considerations with a staged "drill to fill" philosophy can help reduce overestimates and allow for a more prudent phased in approach.
- Consideration for the type of capacity required; e.g. deep-cut versus different degrees of refrigeration, sweet versus sour processing, nodal versus centralized compression and liquid recovery/stabilization, NGL field fractionation versus liquid transport to centralized fractionation facilities.

This list is by no means exhaustive. Infrastructure can represent 20-30% of the total capital required over the full life of the play. For a project to achieve optimal economic returns, it is critical to get this component right.

The design of infrastructure is a staged process with long lead times from conception through to design and construction. At any one time, there is a High, Best, and Low estimate associated with the costs of this infrastructure. The company developing the assets needs to recognize this and model a range of estimates, not a single cost estimate. As the project moves through stages of completion, the cost estimate range narrows. The FDP must incorporate uncertainty for the cost estimates at any point in time.

Egress Options

Modelling Assumptions

TransCanada's system for natural gas was modeled as the product egress option. The option of sending higher liquid content gas down the Alliance pipeline, while often beneficial, was not considered for this study. The Alliance pipeline is assumed to be fully subscribed via long term industry commitments and inaccessible for this exercise.

Consideration is given for making firm (3 year average) commitments for a portion of the gas stream and flowing the remainder as interruptible. Reservoir and development pace uncertainty is decreases over time allowing for more certainty regarding firm commitments. It is assumed the NGTL system will expand as required to meet egress commitments from the area. The standard published tolling methodology for NGTL in this area is incorporated in this model.

Natural gas sales prices are based on AECO pricing less the published NGTL tariffs.

Product egress for liquids (C3+ mix) is assumed to be via pipeline into the Pembina HVP system for transport to Fort Saskatchewan for fractionation and sale. The Pembina system is full and undergoing staged expansions. The current system and future expansions and their subsequent fractionation at Fort Saskatchewan are fully subscribed.

In order to ensure sufficient liquid egress, it was assumed that a 10 year staged increase in liquid volumes in 3 year increments as production ramps up would be committed to with a 5 year staged decrease in volume commitments as liquid volumes drop off.

The portion of liquids not covered by the committed volumes were assumed to be able to flow interruptible. Estimations were made regarding the extent of interruptible capacity accounting for the reservoir productivity and development pace uncertainty and egress access uncertainty. Cost estimates were made for both firm and interruptible liquid transportation and fractionation.

Liquid pricing is referenced to the plant gate after accounting for transportation and fractionation and using the Sproule price forecast.

Risks and Opportunities

It is reasonable to assume that gas or liquid volumes flowing on interruptible capacity will be shut-in for a portion of the time; i.e. egress access is not guaranteed. Recent industry experience has confirmed this as NGTL pro-rationing and long term (typically 10 year) staged volume commitments are required to gain reliable liquid access for transportation and fractionation.

It is difficult for producers to make these commitments given the range of uncertainties related to well productivity and pace of development and the various factors that influence these conditions. Yet commitments must be made in order to provide assurance that the producer will be able to get sufficient product to market to justify the full life development of the project. These commitments can lead to substantial future obligations that increase the financial risk going forward and impact the overall economics of the development play.

A key uncertainty not addressed in this FDP case study is product pricing. The Sproule price forecast makes long term assumptions on oil, gas and liquid prices. It shows a recovery of oil and gas prices from 2015 values with an accompanying recovery of liquid prices. However, there is inherent uncertainty in these forecasts. For example, oil and natural gas prices in Western Canada were low in 2015 when compared to historic averages. While butane and condensate prices are currently profitable, propane and ethane prices do not generate positive netbacks and are currently below their heat equivalent value if left in the sales gas. Understanding price uncertainty must be part of a complete FDP.

Similar to infrastructure, producers need to continually access the marketing expertise necessary to understand the range of uncertainties and make determinations as to the egress commitments they are willing to make. The greater the uncertainty, the less willing producers are to make long term volume commitments. Producers who make the best decisions in this respect will outperform their competitors. Assuming that egress issues will resolve themselves can result in significant negative impact on the economics of the project.

Development Scenarios

Several development scenarios, which are by no means exhaustive, were considered in this study. Each model examined a specific development plan under the Low, Best, and High well productivity cases. For simplicity in the analysis, only the published December 31, 2015 Sproule prices forecast was used. Future product price uncertainty was not considered in this study. A complete FDP must address product price uncertainty.

Scenario 1: Full up front commitment

Scenario 1 represents a decision to fully commit to the project with the goal of increasing production rapidly. It examines a scenario in which a 120 mmcf/d facility is built within five years of the effective date of this study, the size chosen was based on reservoir performance which would be achieved the High case type curve productivity was achieved. Eight wells per year are forecast to be drilled for the first five years using existing infrastructure to process the product volumes. Once the Company facility is operational, the drill schedule is forecast to increase to 16 wells per year.

This scenario represents a company who has not developed realistic type curves and is overestimating future performance of the reservoir.

Egress commitments for the first ten years include three year staged increments for natural gas sales for approximately 70% of the total expected production and 10 year staged increments for NGL transportation and fractionation on the Pembina system for approximately 65% of the total expected production. The remainder of the production is assumed to flow interruptible. This plan provides a reasonable balance between long term service commitments and interruptible service given the early stage of the project.

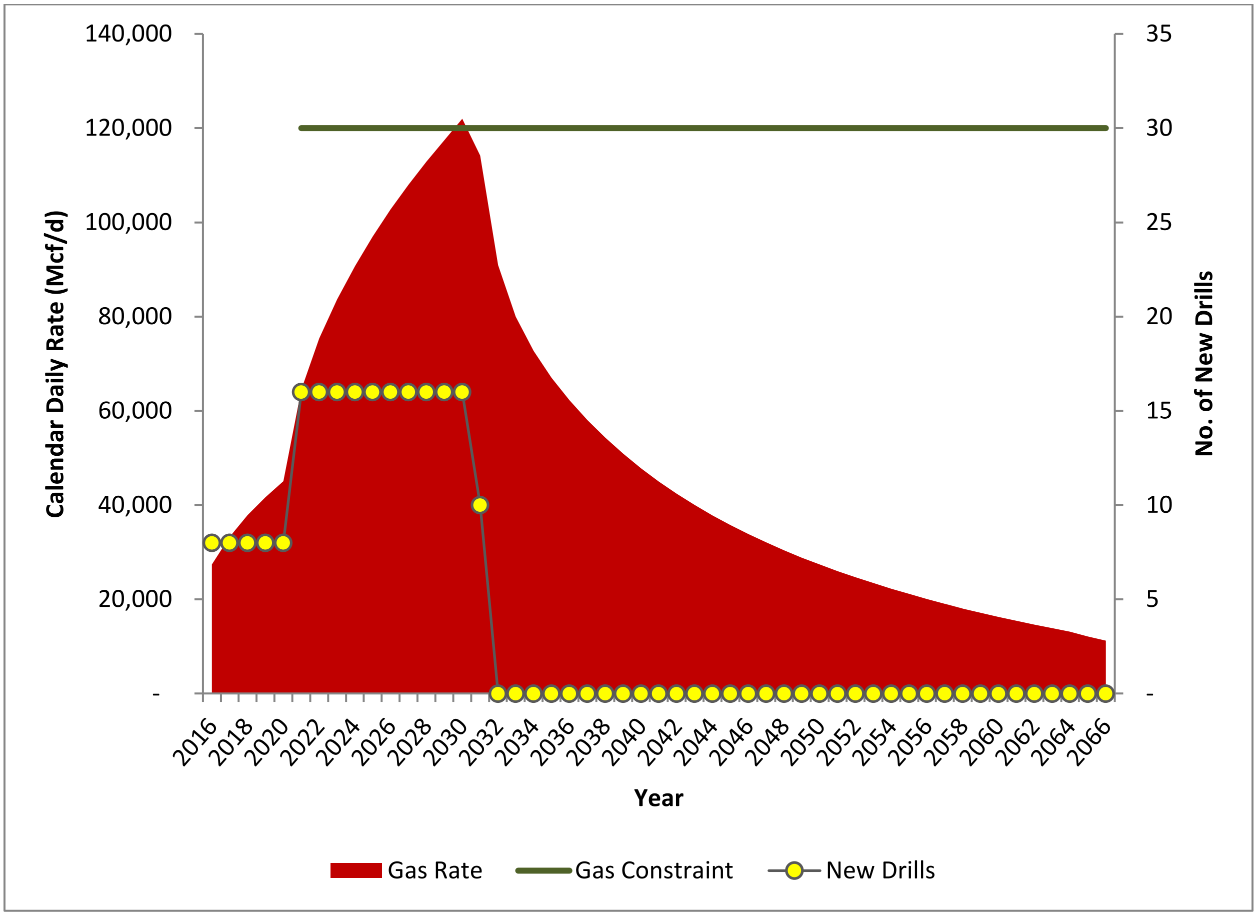

Figure 6: Scenario 1- Upfront 120 mmcf/d facility capacity. Best case production profile.

Scenario 2: Staged infrastructure commitment

Scenario 2 represents a decision to cautiously develop the resource to better balance the infrastructure outlays and egress commitments given the inherent productivity uncertainty. It examines a scenario in which third party infrastructure is utilized for five years, at which point a 60 mmcf/d facility is built with a modular design allowing expansion in the future if required. A "drill to fill" existing capacity philosophy can be employed at any point in time. A plant expansion would be planned and constructed only if High or Best case productivity was achieved. If Low case productivity was achieved, additional infrastructure capacity would not be required. If infrastructure expansion is required, additional product egress capacity must also be obtained.

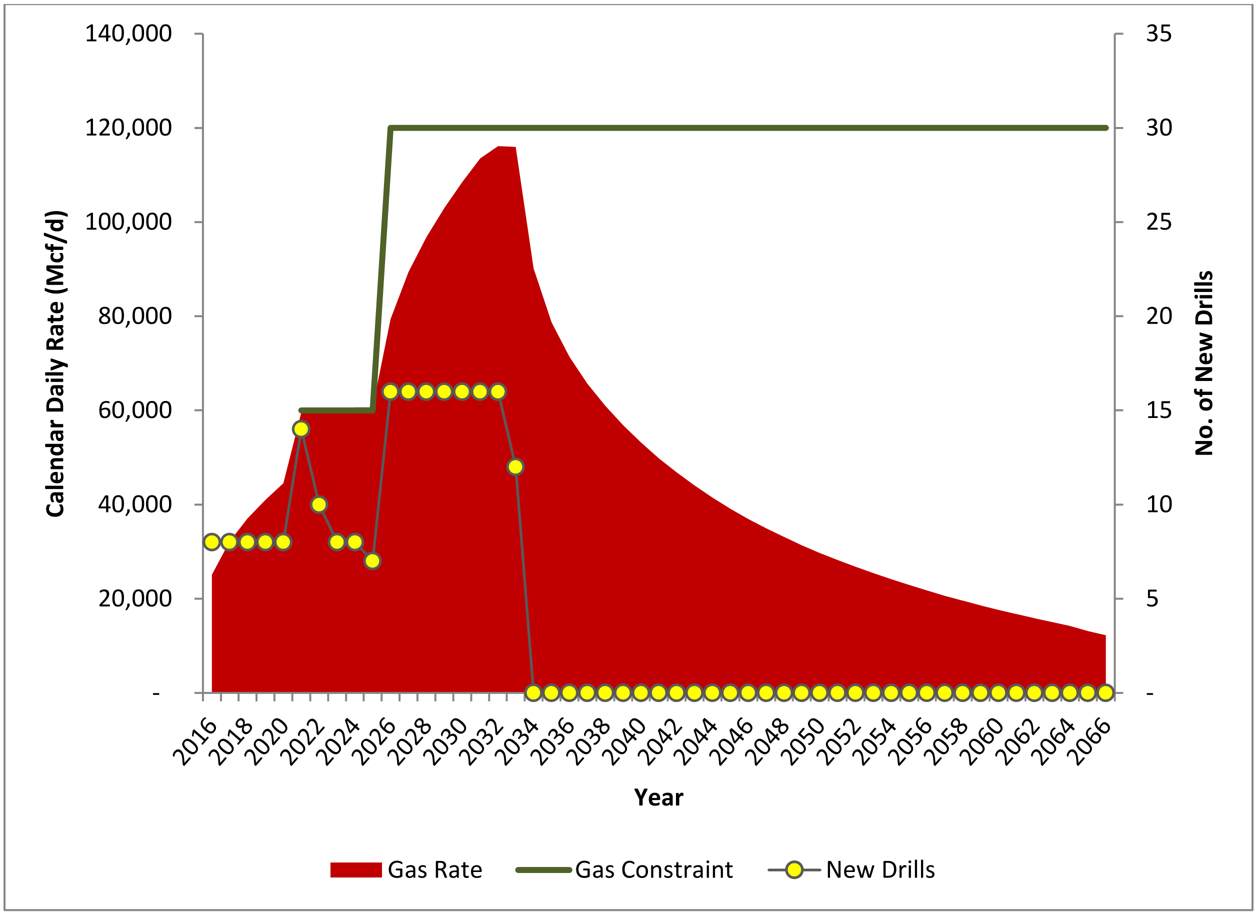

Figure 7: Scenario 2 and 3- Staged capital deployment, expansion as needed. Best case production profile

Scenario 3: Staged infrastructure commitment and 3rd party revenue

Scenario 3 models the same drilling program and staged infrastructure development as Scenario 2, but with a decision to double the facility size and allocate fifty percent of its capacity to process third party gas volumes. In this scenario, the producer receives processing fees and realizes lower per unit operating costs. This risk reducing strategy can only be implemented if the producing company can find an offsetting producer willing to make significant take-or-pay commitments at a negotiated processing fee (using JP-05 guidelines). This arrangement must be to the mutual benefit of both companies. By allocating capital to additional infrastructure, the producing company is using the midstream infrastructure as a hedge against lower performance results, while still allowing the company to develop its assets

Economic Assumptions

Several economic input parameter assumptions were made for this project model. Drill and complete costs were estimated to be eight million dollars per well and representative field operating costs were incorporated. Royalties were based on the Alberta royalty framework ("ARF") calculations. An allowance for abandonment costs was incorporated. Reasonable infrastructure and egress costs were estimated to model project costs from the wellhead through to gas processing and transportation on the NGTL and Pembina system.

Total capital costs were estimated to be between $2.8 and $3.2 billion over the forecasted asset life with approximately 75%-80% related to well drilling and completion costs and the remaining 20-25% of the costs related to surface infrastructure. The split between well development and infrastructure cost changed slightly, depending on which scenario was modeled. Maximum egress commitments for the first 10 years were estimated to be $60 to $80 million.

Scenario Results

Scenario 1 represents an aggressive growth strategy, with the goal of maximizing production. Figure 8 presents the difference in NPV that could occur relative to the Scenario 1 High case, depending on which outcome is realized. These are differences in NPV10 between productivity cases, not absolute values. If a company is expecting High case results, but instead Low case results are achieved, the project would generate over 700MM$ less in NPV10. While if High case production is achieved the project would generate a greater than 10% rate of return; however, if the Low case production were achieved the project would not be expected to payout. This could present a significant risk to the company's future, as the downside case would be uneconomic.

An alternative development strategy is to develop the project as described in Scenario 2, starting with a lower capacity design but allowing for future expansion. This represents a company who realizes that there is uncertainty in the reservoir productivity and wants to design to mitigate some of the risk, as opposed to developing to maximize production rates. The High case value remains similar to Scenario 1 but the value of the Low case is significantly improved. The Low production case in this scenario now generates a positive rate of return. Additionally, the spread in NPV10 between the Low and High productivity results is decreased. This development strategy reduces the overall risk of this project.

Further risk reduction is illustrated under Scenario 3. The addition of 3rd party volumes reduces overall unit operating costs and provides processing fee revenue generating reasonable return on the added infrastructure capital.

Figure 8 summarizes the three scenarios NPV10 relative to Scenario 1 High Case. The company is able to add value and reduce the overall risk to the project by proactively investigating their infrastructure development and egress options. If the High case production results are achieved, the producer will realize similar NPV10 to Scenario 1, however, if Low case production is achieved, the producer will realize much better NPV's. This may be the difference between an economic and uneconomic result if Low case performance is realized.

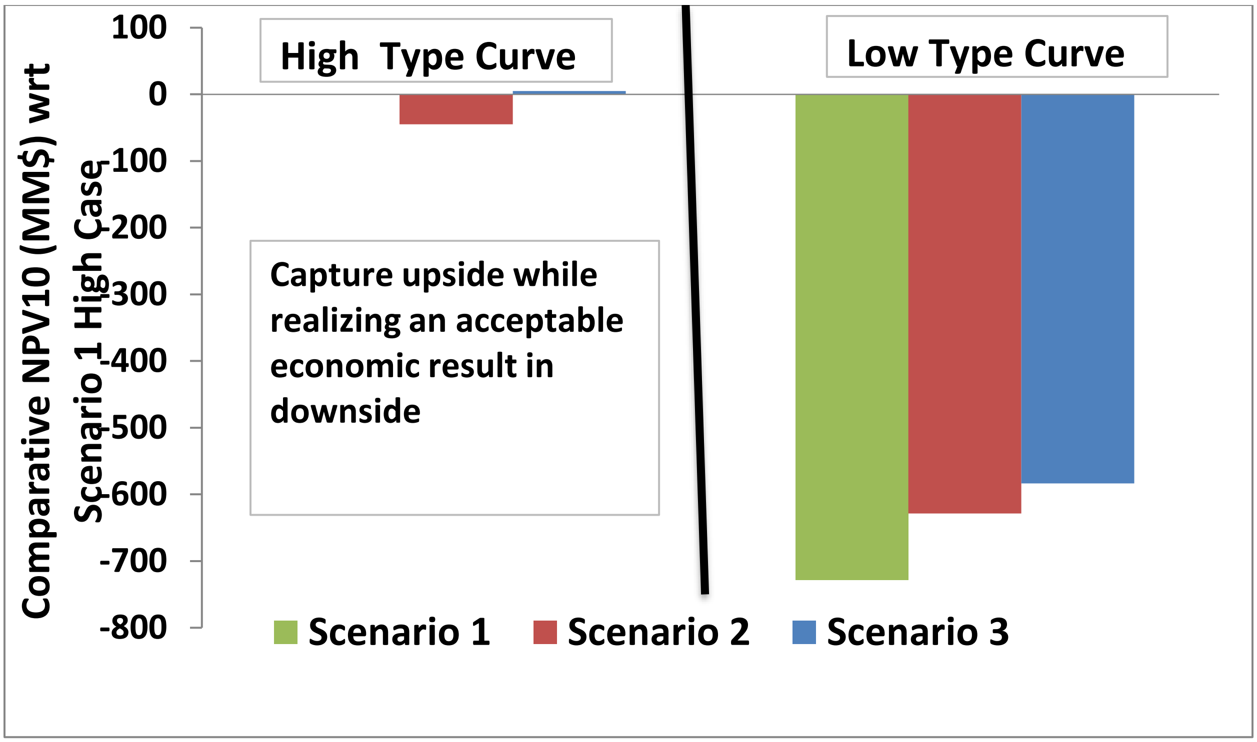

Figure 8: High case and Low case comparative results with respect to Scenario 1 High Case

While NPV10 and rate of return are important metrics in which to gauge projects and development plans, they are not the only important factors. Annual capital budgets/constraints and corporate cash flows are also important as companies continually realign priorities to maintain their balance sheets. As a result, the highest NPV10 development plan is not necessarily the preferred plan for any individual project.

Figure 9 presents the capital spent during the first ten years of the development. This major field development has significant capital requirements and the capital profile and cash flow projected has to align with the producing company's objectives and constraints.

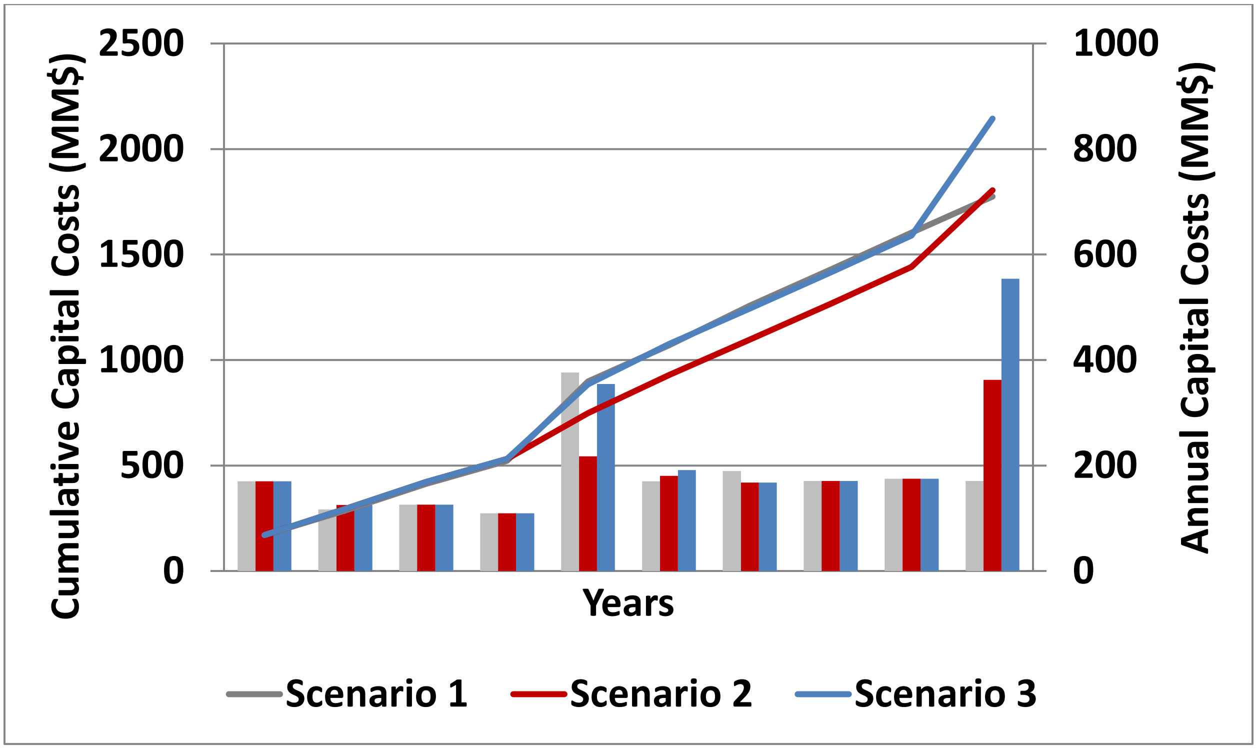

Figure 9: Best case capital projection by scenario for first 10 years

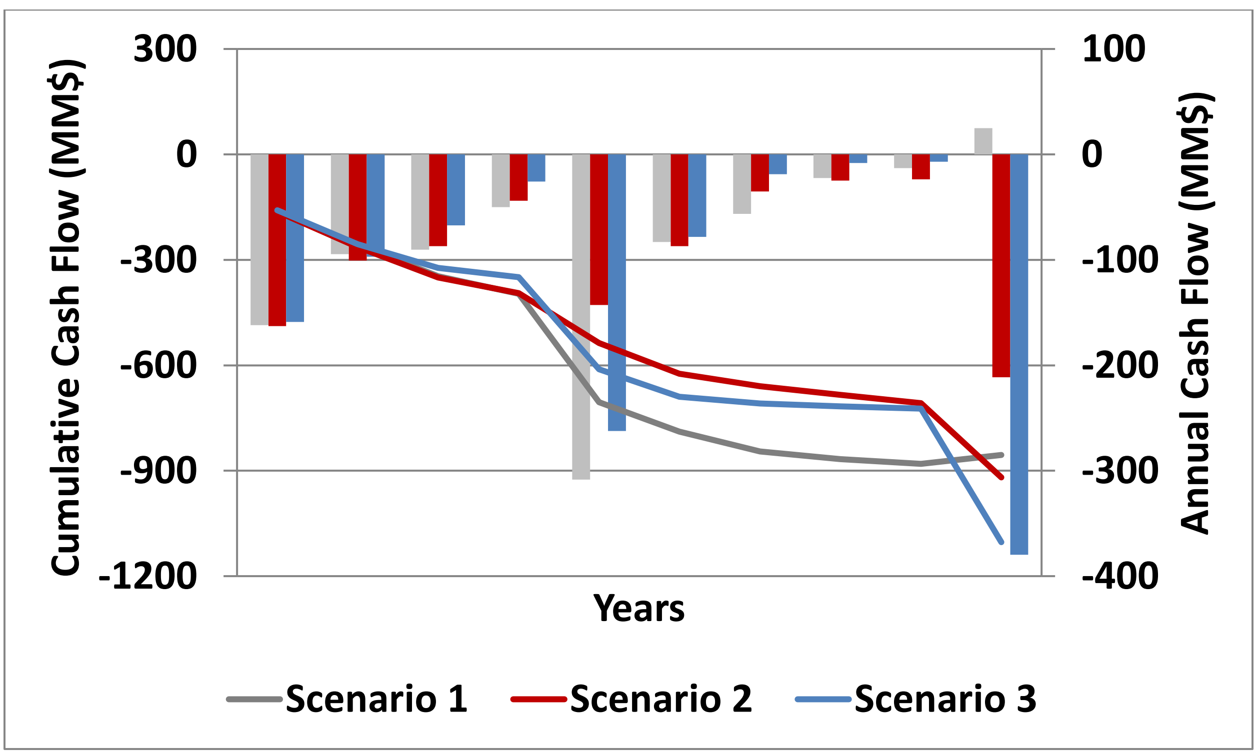

Figure 10: Best case cash flow projection by scenario for first 10 years

Conclusions

There are inherent risks and uncertainties throughout the life of a development project. These risks and uncertainties need to be addressed in a FDP. The FDP should identify and address all significant risks and uncertainties and allow the producer to maximize upside potential while reducing the economic risk of a downside performance result. Proper planning, simultaneously incorporating reservoir, infrastructure and egress variability is needed to ensure the company will make the best possible decisions when developing their project.

The simple analysis above illustrates these concepts using the high reward/high cost Duvernay play as a foundation. All of the scenarios presented are modelling the same reservoir but show that by changing the development plan, economic results can vary significantly. It shows that through proper planning, the FDP can help a company to maximize the upside economic potential while mitigating downside economic risk.

The case study as shown is a partial analysis, with only a few variables considered. Even with the limited scope, a large variation in potential outcomes is possible.

A complete FDP would address additional material variable over the entire value chain. It would highlight opportunities for growth and risk mitigation and ensure alignment within a company's capabilities, capacities and strategies. Some of the addition factors which should be incorporated into a FDP are:

- The asset's strategic fit within the corporate portfolio
- The company's strategic plan including development, exit and funding strategies
- Land availability and acquisition strategies
- Optimal reservoir depletion strategies
- Product price uncertainties
- Capital cost uncertainties
- Operating cost uncertainties
- Integrated reservoir, infrastructure and egress project planning and timelines
- Regulatory requirements, constraints and emerging issues
- Meeting all stakeholders needs and the associated cost and/or risk/uncertainty in doing so plan of having to do so; especially as the FDP is spread out over several years or in stages
- Commercial considerations and contracting strategies
- Organizational, construction and operation staffing issues
- Environmental issues
- Production rate targets
- Annual capital targets and constraints
- Cash flow targets
- Rate of return and NPV targets

- Decision points/milestones to trigger major investment decisions
- Market considerations
- 3rd Party area development plans and competitive/available facilities

The above list is by no means complete and not every factor will be material for each company. Companies must diligently plan their major projects and understand the risks, uncertainties, and upside potential in order to optimize their development. In a high product price environment many projects generate positive returns even if they not developed optimally. In a low and recovering product price environment a thorough field development plan may be the difference between a project's and company's success or failure.

Sproule GMPi Alliance

GPMi and Sproule are recognized as respective industry leaders in reservoir analysis and infrastructure planning and evaluation. They are uniquely positioned to provide integrated field development planning service offerings including A&D valuation, LNG feedstock planning, natural gas and gas liquids supply forecasts and market analysis, reservoir development, infrastructure analysis and opportunity identification, and training solutions all designed to maximize asset value.

Established in 1999, GPMi is an independently owned consulting company that provides leading oil and gas surface planning and evaluation services to a full spectrum of clients. Located in Calgary, GPMi has developed considerable North American and International expertise in the assessment, strategy development, opportunity identification and implementation for gathering, processing, energy and market connection infrastructure. GPMi provides expert related advisory services for A&D, market analysis, electricity, NGL, LNG and petrochemicals, area studies on emerging plays or key market segments and commercial facilitation.

Sproule's truly independent and trusted reports provide confidence and protection to all stakeholders in the oil and gas industry. Sproule is one of the world's premier petroleum consulting and advisory firms, anchored by over 60 years of experience assisting companies with the evaluation of oil and gas reserves and resources, M&A related due diligence, capital planning, industry training and reservoir studies. The head office in Calgary, Canada is supported by satellite offices in Bogotá, Colombia, Rio de Janeiro, Brazil, and Brisbane, Australia.

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Matthew is a Partner of Sproule and has been a Sproule professional since 2011. He has experience in both the Western Canadian Sedimentary Basin and internationally. He is experienced in conventional oil and gas, heavy oil and unconventional tight and shale plays. Aspects of Matthew's role include evaluations, audits, field development planning, A&D due diligence, and capital planning.

Matthew is currently the Practice Manager for the Capital Strategies group at Sproule, with a focus on assisting clients to use data to make better decisions as to how to most effectively deploy capital.

Matthew holds a Bachelor of Science, Mechanical Engineering degree from the University of Alberta and is a member of both APEGA and the SPE.

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Terry has over 36 years of experience in oil and gas industry in Western Canada encompassing infrastructure planning and project management, business development, contract negotiations and A&D, upstream resource assessment and development, operations and HSE.

He joined GPMi in 2010 providing consulting services in several areas including midstream strategy development, opportunity identification through to their engineering design and construction, midstream business modelling and asset evaluations and third party and joint venture negotiations.

Prior to joining GPMi, Terry worked in the O&G industry mainly in executive level and managerial leadership roles in financial, upstream and midstream sectors.

Terry holds a Masters of Engineering Degree from Carleton University and a Master of Arts degree in Economics from the University of Ottawa.