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EXECUTIVE SUMMARY

The development of shale gas/oil resources in Pakistan is mainly dependent on the confirmation of availability of shale gas/oil resources (described in Component 1 of this study), the required exploitation technology, infrastructure, financial feasibility, environmental risks, and required regulatory regime. Exploitation of such unconventional resources is vital for meeting energy shortages, and reduction of oil and gas imports in the decades to come. Using the available data, this study seeks to provide a basin level shale gas/oil potential in Pakistan, followed by technology, infrastructure, and economic assessment of shale gas/oil exploitation in the four targeted formations, i.e., Ghazij, Ranikot, Lower Goru, and Sembar located in the Middle and Lower Indus Basins. The overall study focuses on two main areas:

- Component 1: Providing shale gas/oil resource assessment of the four formations using existing data from wells located in the Middle and Lower Indus Basins. Component 1 consisted of Milestone 1 to 4.
- Component 2: Evaluating potential economic viability, keeping in view the numerous aspects associated with and directly related to shale gas/oil exploration and production. Component 2 consists of Milestone 5 to 7.

As part of the component 2, Milestone 5; this report discusses the following areas:

a. Shale gas/oil related technology assessment;
b. Infrastructure assessment including roads, pipelines, and water availability;
c. Development of work plan for optimum shale gas/oil exploitation;
d. Capital investment profile (i.e., financial feasibility assessment) to ascertain the production cost; and
e. Review of current legal, regulatory and fiscal framework with an objective to cover the operations for shale gas/oil exploitation.

To make an assessment of the current Exploration and Production (E&P) industry in Pakistan, surveys and interviews were conducted with almost all key E&P and service companies currently working in Pakistan to learn about their current capabilities and to gauge their interest and preparedness for shale exploitation projects. Companies in the United States were also interviewed to learn about their experiences in developing shale projects in order to identify any gaps in this domain.

The availability of technology and infrastructure were emphasized as the main areas of interest in this study. Through various discussions with the stakeholders and review of materials, it became apparent that the technology required for shale gas/oil exploitation operations is already available in Pakistan but only at a limited scale. Primarily, horizontal drilling and hydraulic fracturing is required for shale gas/oil wells. In Pakistan both these technologies are deployed for conventional and tight gas operations. There are about 48 rigs out of which 28 are deep drilling rigs. Whereas the basic technology is available, it will have to be scaled up for full shale gas/oil operations. The required equipment will have to be imported with a lead time of 3-6 months depending on the equipment, which is not a deterrent for the service companies already operating in Pakistan. Rather, service companies will be encouraged to provide such specialized equipment in Pakistan at a competitive rate should shale gas/oil exploitation activities commence in Pakistan.

Among Exploration and Production (E&P) companies interviewed, Pakistan Petroleum Limited, Eni, and Oil and Gas Development Company Limited are key players keen for shale operations. When it comes to service companies, Schlumberger has a full range of equipment available including the only frack fleet available in the country. Weatherford and Halliburton having global capability are also keen to participate in shale gas/oil projects in Pakistan. Furthermore, smaller specialized companies are
providing the directional drilling, Measurement While Drilling (MWD), and Logging While Drilling (LWD) tools required for shale operations.

The majority of Middle and Lower Indus Basin area is already licensed or leased to various companies that are carrying out conventional oil and gas operations. The infrastructure in this area is sufficient for the initial pilot projects for shale gas/oil development. This infrastructure includes roads, gas processing facilities, and pipeline infrastructure. Whenever a need arises as part of their business operations, the E&P companies would build or tie in pipelines, processing plants, and roads at their own cost. The pipeline capacity will be required to be enhanced to provide for full cycle shale gas production; however, this requirement would become evident depending on the success of the pilot projects. These initial projects will determine the full production potential of the identified resource down the line, which can take up to 5-10 years to materialize, giving ample time to the downstream companies to augment their systems.

Availability of water is considered a key requisite for shale operations due to the amount of water (i.e., 3-8 million gallons per well) generally used for hydraulic fracturing. Data on water availability is very limited; however, for initial limited (pilot) scale development water would be available. A separate detailed assessment on water availability is recommended as per this study.

Following are the alternates that can be adapted for large scale shale gas/oil development operations:

1. Desalinated water can be provided by way of installing a desalination plant at Karachi and transporting the water to Middle and Lower Indus Basin.
2. New technologies are being developed, such as use of CO₂ to replace the water for fracturing. The Middle and Lower Indus Basin has significant resources of CO₂, which can be considered for use for fracturing after treatment.

For making assessment of typical shale gas operations, a shale gas development work plan has been prepared on the basis of two different drilling and completion scenarios: horizontal drilling and vertical drilling. The work plan was devised in order to simulate the drainage of one section (i.e., 1 square mile) of shale gas. For horizontal well development each section was developed with four wells (1,220 m or 4,000 feet horizontal) each based on a drainage area of 156 acres, or one fourth of the 640 acre section. For vertical well development, 23 wells were assumed to be drilled in each section. The work plan also provides the optimum number of hydraulic fracture stages.

The inputs from the industry survey and the above mentioned work plan were used for carrying out the financial assessment. The financial model for a total of thirteen (13) sections of 1 square mile each was built in order to estimate the break-even cost of gas (US$ per MMBTU). However, as part of the optimization process and in some cases due to the data selection criteria, five (5) sections were selected.

The financial analysis was performed using data for the Sembar and Lower Goru shale formations. The Ghazij and Ranikot formations, due to limited samples availability, maturity filter criteria, and uneconomical simulated results, were not included in the financial analysis.

The financial model considers the required capital expenditure and operational costs, including drilling costs and subsurface installations. Stimulation/hydraulic fracturing and the wellhead costs were calculated. The base case operator take has been assumed at 20%.

Accordingly, a volumetric average cost was arrived at using the following assumptions for four different cases (sensitivities):

**Case 1:** Operator take assumed to be at 25%

**Case 2:** Operator take assumed to be at 15%

**Case 3:** A tax and royalty holiday for a period of 10 years (for comparison with imported gas)
**Case 4:** Required quantities of freshwater are not available in the area of development and desalinated water would be used.

The results were further summarized to look at short term (5 years), mid-term (5-10 years) and long term (more than 10 years) development scenarios for achieving improved levels of capital expenditure (CAPEX) optimization.

<table>
<thead>
<tr>
<th>Wellhead Cost Per Unit (US$/MMBTU)</th>
<th>Short Term Case</th>
<th>Mid Term Case</th>
<th>Long Term Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case Breakeven Cost</td>
<td>11.21</td>
<td>9.94</td>
<td>8.67</td>
</tr>
<tr>
<td>Parameters</td>
<td>Break Even Cost</td>
<td>Break Even Cost</td>
<td>Break Even Cost</td>
</tr>
<tr>
<td>Case 1 Operator Take 25%</td>
<td>11.91</td>
<td>10.55</td>
<td>9.19</td>
</tr>
<tr>
<td>Case 2 Operator Take 15%</td>
<td>10.43</td>
<td>9.25</td>
<td>8.08</td>
</tr>
<tr>
<td>Case 3 No Tax + No Royalty</td>
<td>9.07</td>
<td>8.05</td>
<td>7.02</td>
</tr>
<tr>
<td>Case 4 Using 100 % Desalinated &amp;/or Produced Water</td>
<td>11.64</td>
<td>10.3</td>
<td>8.97</td>
</tr>
<tr>
<td><strong>High</strong></td>
<td>11.91</td>
<td>10.55</td>
<td>9.19</td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td>9.07</td>
<td>8.05</td>
<td>7.02</td>
</tr>
</tbody>
</table>

The analysis shows that the base average volumetric cost would be $11.21 per MMBTU for short term, $9.94 per MMBTU for mid-term, and $8.67 per MMBTU for the long term case. These are only indicative numbers and based on these estimates the government may decide to provide incentives in the policy for shale gas development.

As part of this report, existing legal, regulatory, and fiscal regimes were reviewed to look at the current prevailing practice in Pakistan for the conventional oil and gas sector. The in-depth analysis will follow this report as part of the subsequent milestone which will cover a detailed comparison of Pakistan petroleum regime with that of other countries and provide recommendations thereof in respect of identifying the areas for improvement to meet the shale gas/oil development requirements. The Shale Gas Guidance Document is planned to provide a summary of the findings and proposed solutions.
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I. INTRODUCTION

The United States Agency for International Development (USAID) under an agreement with the Government of Pakistan is providing support to Ministry of Petroleum and Natural Resources (MPNR) [Director General Petroleum Concessions (DGPC)] through the Energy Policy Program (EPP). This support includes assessment of unconventional (shale gas/oil) resource and technology in the area of interest (Lower and Middle Indus Basin) by engaging the services of specialized companies having requisite expertise in the field. Advanced Engineering Associates International Inc. (AEAI) was contracted by USAID to manage the program. This Shale Gas and Oil Resource and Technology Assessment is a study of identified shale formations in the Middle and Lower Indus Basin of Pakistan, namely Ghazij, Ranikot, Lower Goru, and Sembar. The primary objective of the study is to conduct resource assessment and determine the economic viability of shale gas/oil exploitation in the four targeted formations using the available well data. This report is the outcome of the assessment which covers the evaluation of appropriate production technology, infrastructure needs, and shale gas/oil production costs by:

- Reviewing the recent developments in the technologies in the US and globally and application of these technologies in Pakistan;
- Reviewing the availability of necessary infrastructure (e.g., rigs, sand, water, transmission, etc.);
- Identifying the service companies in the field that can deliver the required technology and innovative tools for shale gas/oil exploitation;
- Recommending the prospective areas (“sweet spot” analysis) to initiate the shale gas/oil drilling to attain fast production based on existing facilities, gathering systems, and pipeline access;
- Developing a work plan for drilling, completion, and stimulation processes by using simulated production profiles, which can facilitate the planning and exploitation of the identified potential sweet spots and zones as pilot project(s); and
- Developing indicative expected capital investment, estimates of the recoverable resource for the identified area by applying the recovery factor computed as a result of production volumes within a time period to compute the production cost.

The commercial proposition for shale gas/oil development is a complex matter and depends on the in-place resource and its yield. Parallels can be drawn with the experience of the shale gas/oil industry in the USA, although the method and rate of developing shale gas/oil resources in Pakistan may differ. These include the volume and pace of conventional oil and gas resource development, related infrastructure availability, economic feasibility, and the regulatory framework.

This report focuses on the economic feasibility and technology assessment for fast and efficient exploitation of shale gas/oil only. The environmental aspect of the shale gas/oil resource development and the related regulatory framework are partly covered in this report. Details on regulatory framework and environmental aspect will be covered in the subsequent milestone.
2. **SHALE GAS AND OIL RESOURCE ESTIMATION AND SWEET SPOTS**

The results of Component 1 of this study provide an assessment of shale gas/oil resources in the four targeted formations in the Middle and Lower Indus Basin. The assessments are based on application of shale specific petrophysical model and interpretation of existing data from conventional well logs and cores and cuttings.

Using the results of the analyses, the potential wells and zones within the formations of interest were narrowed down and a superimposed Hydrocarbon Pore Volume (HCPV) map was generated with all four formations overlaid to identify areas of combined hydrocarbon volumes based on property modeling. For sweet spot identification, the oil and gas maturity was applied to the HCPV (Figure 1 and Figure 2). In these maps, there are some concentrated regions (red) as per the modeling results showing a strong potential for shale gas/oil in the formations of interest. Using four different drilling and completion scenarios (e.g., vertical and horizontal), the production simulation was performed for selected wells and zones within the formations of interest. The simulated production results were mainly used to calculate recovery factors of these zones and formations.

This study has identified the potential areas and regional sweet spots in the Middle and Lower Indus Basin. These sweet spots were used as potential areas for further focused work including the production cost estimates. It also provides the basis for further work using seismic pilot programs followed by actual drilling, completion, and production activities after the award of concessions and leases.

Hydrocarbon volumes are calculated in the 3D property model using standard volumetric calculations. Applying formation volume factors to the reservoir fluid volume causes these values to be reported as in-place surface volumes. The Depth to Maturity [based on measured vitrinite reflectance in oil] (Ro) maps are used to distinguish between the oil and gas phase windows. The Oil In-Place (OIP) and Gas In-Place (GIP) (Free and Adsorbed) maps are the end product of this volumetric calculation process. Table 1 below shows the in-place, recoverable, and risked recoverable shale gas/oil resource based on the analyses performed in this study.

<table>
<thead>
<tr>
<th></th>
<th>Ghazij</th>
<th>Ranikot</th>
<th>Lower Goru</th>
<th>Sembar</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OIP (BSTB)</strong></td>
<td>450</td>
<td>154</td>
<td>910</td>
<td>809</td>
<td>2,323</td>
</tr>
<tr>
<td><strong>Free GIP (TCF)</strong></td>
<td>186</td>
<td>14</td>
<td>1,664</td>
<td>1,914</td>
<td>3,778</td>
</tr>
<tr>
<td><strong>Technically Recoverable OIP (BSTB)</strong></td>
<td>11</td>
<td>4</td>
<td>22</td>
<td>21</td>
<td>58</td>
</tr>
<tr>
<td><strong>Technically Recoverable Free Gas (TCF)</strong></td>
<td>9</td>
<td>1</td>
<td>79</td>
<td>99</td>
<td>188</td>
</tr>
<tr>
<td><strong>Risked Recoverable OIP (BSTB)</strong></td>
<td>1</td>
<td>0</td>
<td>7</td>
<td>6</td>
<td>14</td>
</tr>
<tr>
<td><strong>Risked Recoverable Free Gas (TCF)</strong></td>
<td>1</td>
<td>0</td>
<td>41</td>
<td>52</td>
<td>95</td>
</tr>
<tr>
<td><strong>Adsorbed GIP (TCF)</strong></td>
<td>57</td>
<td>8</td>
<td>3,702</td>
<td>2,614</td>
<td>6,381</td>
</tr>
</tbody>
</table>

Adsorbed gas in-place is not considered in the recovery factor calculation as well as the production profile simulation. To understand the contribution of adsorbed gas, shale gas production data and further laboratory testing (e.g. desorption) must take place to yielding pressure differential requirements and Langmuir values. Since these values vary throughout different plays, an estimated percentage to total contribution cannot be made at this time. The Total Organic Carbon (TOC), pressure, and Langmuir Isosterm values used in the adsorbed
gas in-place calculation, on discount for risk are, respectively \((0.8 \times 0.65 \times 0.2) = 0.104\) or 10% of calculated adsorbed in the gas maturity window only.

The Figure 1 and Figure 2 below show combined for the four formations Hydrocarbon Pore Volume Map with Oil and Gas maturity windows, respectively, which identify areas of a hydrocarbon volumes based on modeling and thermal maturity. Along with Hydrocarbon Pore Volume (HCPV), (Oil and Free Gas Pore Volume) maps the geomechanical properties (e.g., VCLAY, Brittleness etc.) are important from drill-ability perspective.
Figure 1: HCPV Sweet Spot Map for Oil
Figure 2: HCPV Sweet Spot Map for Free Gas
As per the program plan, the findings in Component-1 (i.e. Shale Gas/Oil Resource Estimates) provided input for this report in production cost estimates and infrastructure assessment. The assessment under this Milestone will eventually help in the preparation of the Policy and Regulatory Framework Guidance Document for exploitation of the shale gas/oil resource.
3. SHALE GAS/OIL EXPLOITATION TECHNOLOGY

Unconventional natural gas deposits are difficult to characterize, but they are often lower in resource concentration, more dispersed over large areas, and require well stimulation or other extraction or conversion technology\(^1\). These resources are termed as “unconventional” or “continuous” resources because their extraction required unconventional means such as horizontal drilling and stimulation/hydraulic fracturing. The porosity, permeability, fluid trapping mechanism, or other characteristics of an unconventional reservoir differ greatly from conventional sandstone and carbonate reservoirs. In the case of shale gas/oil resources, the reservoir and trap for the hydrocarbon is found within the same shale rock. These types of resources are also called Source Rock Reservoirs (SRR). \(^2\)

Horizontal drilling and reservoir stimulation techniques have been employed for many years by oil and gas companies for the exploitation of shale gas/oil. Although the similar techniques are also used in conventional reservoir for enhanced oil/gas recovery. Both free and adsorbed gas are produced through these techniques; the difference in case of adsorbed gas is that it starts contributing into the production when the reservoir is depleted to a level where the desorption pressure is reached and the adsorbed gas detaches from the shale and starts contributing in the production all the way from the fracture network produced during hydraulic fracturing to the wellbore.

HORIZONTAL DRILLING AND HYDRAULIC FRACTURING

Shale gas permeates a layer of impermeable source rock over an extended area. To expose more of the shale gas pay zone to the wellbore horizontal and lateral drilling are used, especially if the target zone thicknesses range around 30 to 50m. The horizontal drain is kicked off at the base of a vertical hole at an average depth of 1,500 to 3,000 m and can extend over a distance of 1,000 to 2,000 m horizontally. This has led to reducing the surface footprint of oil and natural gas activity, i.e., the surface disturbance is reduced by a single horizontal well where more vertical wells might be needed. In the US multiple horizontal wells are drilled from a single “pad” at the surface.

A horizontal well is drilled parallel to the bedding and its angle depends on the structural dip of the target rock unit. The angle (and orientation) of the horizontal well depends more on the geometry of the sweet spot being chased. The technology thus helps in fracturing large sections of low porosity-permeability shale targets wherein the un-expelled oil and gas starts to flow due to the artificially enhanced petrophysical characteristics.

The shale rock layers need to be fractured or “fracked” before the oil and gas can flow to the wellbore. Pressurized liquid is injected into the rocks in order to create fissures and release the gas and oil. Figure 3 illustrates that oil and gas production in shale and other low-permeability rocks requires the hydraulic stimulation of vertically oriented, radial fractures that emanate from a horizontal wellbore.

\(^1\) [http://www.api.org/policy-and-issues/policy-items/exploration/facts_about_shale_gas](http://www.api.org/policy-and-issues/policy-items/exploration/facts_about_shale_gas)

\(^2\) Kenneth E. Williams
Hydraulic fracturing produces permeability, where it is not naturally present, by producing a network of cracks. The injection water is mixed with:

- **Proppants** - Materials such as sand or ceramic balls that hold the cracks open after they have been formed

- A limited quantity of additives (in the order of 0.5% of the total injection volume). These additives are mainly bactericides, gelling agents, and surfactants. (See Figure 4 below.)

The composition of the additive package depends primarily on the well conditions: pressure, temperature, proppant quantity, etc. In addition to sterilizing and preventing bacterial contamination of the reservoir, the additives serve to improve the efficiency of the process. Each well must be fractured in several stages; the less permeable the reservoir, the more stages are needed.
GLOBAL SHALE GAS/OIL TECHNOLOGY DEVELOPMENTS

Over the years, significant technology development in the oil and gas sector has increased efficiency, reduced time, and has led to cost reductions. When it comes to shale gas/oil, global technology developments have made it possible to release natural gas and oil from compact rocks, such as, shale and “tight” sandstones. This has resulted in the increased potential of unconventional oil and gas.

As stated above, there are two key technology developments that have helped unlock unconventional oil and gas potential: horizontal drilling and hydraulic fracturing.

Drilling technology has improved substantially in recent times, and by using improvements in drilling equipment, such as, top-drive drilling rigs and bottom-hole rotary steerable tools, drillers are able to drill long horizontal wells and to place the bore-hole more accurately in specific locations. Horizontal drilling has applied geosteering technologies (real-time adjustments) that keep the wellbore centered in the target zone and properly aligned to the optimum azimuth. Geosteering is important as shale beds can be extremely thin. (The lateral sections of the first Bakken well had to stay within a layer no thicker than 15 feet (5 m) at its widest points — and less than 6 feet (1.8 m) at its narrowest.) These techniques are not only used in shale plays, but have also been extensively developed for deep water projects.

The technology that has really advanced due to shale exploration is hydraulic fracturing. Hydraulic fracturing has been used in the petroleum industry since the 1940s to enhance oil production in conventional oil reservoirs, but its use has evolved through time. Hydraulic fracturing typically utilizes significant quantities of water (3 million to 8 million gallons per well). It is considered a controversial method due to the amount of water it requires along with the fact that the process poses a huge risk to clean drinking water and public health, and there is potential for deep underground water contamination. As countries are becoming aware of these environmental threats, service companies are looking into methods that will reduce the use of water or completely replace it. Some of the innovative measures taken by service companies include:

- Methods that help reduce the amount of fresh water use (e.g., HiWAY by Schlumberger reduces water use by 25%).
- Experiments to determine whether 100% produced water can be used as a fracturing fluid (e.g., xWater and FracCON by Schlumberger, and UniSTIM by Halliburton).
- Terra Slicing Technology (TST), is a process which is similar to hydraulic fracturing; however, it is safer and is considered to be faster. The process of terra slicing involves cutting through damaged zones in the ground, increasing permeability, creating non-existent vertical permeability avoiding damage caused by perforation, and increasing the drainage area. But it will not be as useful when it comes to shale as permeability will only increase near the wellbore (for more information please visit: http://www.falconridgeoil.com/).
- GasFrac’s fracturing system, which uses a gelled fluid containing propane. The gel retains sand better than water. It is possible to get the same results with one-eighth the liquid and to pump at a slower rate. The fluid can simply merge into the flow being extracted from the ground, eliminating the need to drain contaminated wastewater and disposing of the same into injection wells.

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3 Azimuth is the compass direction of the wellbore as planned or measured. The azimuth is usually specified in degrees with respect to the geographic or magnetic north pole.
4 The HiWAY service uses specialized blending equipment and control systems to pump proppant in pulses—creating stable, infinite-conductivity flow channels within the fractures (for more information please visit slb.com)
DryFrac waterless fracturing technology using liquid CO₂. Praxair, the largest industrial gas company in the Americas, recently launched its DryFrac, which mixes CO₂ with the proppant before introducing it to the formation. The company says it can separate the CO₂ returned from the well after fracking. The method is being tested in a sandstone formation in Oklahoma. Lack of CO₂ gas pipelines is a major hurdle in the use of this method.

Treating wastewater is being prioritized and on-site treatment is being sought and becoming increasingly available (e.g., Clean Wave treatment system by Halliburton).
4. **AVAILABILITY OF TECHNOLOGY IN PAKISTAN**

This study has highlighted the extensive technological advancements that have been made to exploit the full potential of shale resources in the USA. To estimate the degree of readiness in terms of the technology availability in the oil and gas industry in Pakistan, information was gathered from multiple E&P operators and service companies listed in Table 2 below, about their views on shale gas/oil resources and its exploration and exploitation. Furthermore, information was also gathered from companies in the USA to determine the practices followed there.

**Table 2: Companies Interviewed for the Study**

<table>
<thead>
<tr>
<th>E&amp;P Companies</th>
<th>Service Companies</th>
<th>US Companies</th>
</tr>
</thead>
<tbody>
<tr>
<td>ENI Pakistan (M) Limited S.A.R.L</td>
<td>Schlumberger</td>
<td>Gearhart</td>
</tr>
<tr>
<td>New Horizon Exploration and Production Limited</td>
<td>Weatherford</td>
<td>Halliburton US</td>
</tr>
<tr>
<td>United Energy Pakistan Ltd. (UEPL)</td>
<td>Baker Hughes</td>
<td>Stonegate Production</td>
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<tr>
<td>OMV (Pakistan) Exploration Gesellschaft M.B. H.</td>
<td>Halliburton</td>
<td></td>
</tr>
<tr>
<td>Hycarbex Inc.</td>
<td>Sinopec</td>
<td></td>
</tr>
<tr>
<td>PGNiG – Pakistan</td>
<td>Dewan Drilling</td>
<td></td>
</tr>
<tr>
<td>Oil and Gas Development Company Limited (OGDCL)</td>
<td>Eastern Drilling Services (EDS)</td>
<td></td>
</tr>
<tr>
<td>MOL Pakistan Oil and Gas Company B.V.</td>
<td>KCA Deutag</td>
<td></td>
</tr>
<tr>
<td>Pakistan Oilfield Limited (POL)</td>
<td>CNPC: Chuanqing Drilling</td>
<td></td>
</tr>
<tr>
<td>Mari Petroleum Company Limited (MPCL)</td>
<td>Sprint Oil &amp; Gas Services</td>
<td></td>
</tr>
<tr>
<td>Pakistan Petroleum Limited (PPL)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

As per the information gathered from these companies, both horizontal drilling and hydraulic fracturing technologies are available and the E&P companies use both technologies to develop their resources. When it comes to hydraulic fracturing in particular, this technology is expensive in Pakistan at present due to limited demand and availability.

Fracturing technology has been used in Pakistan for old wells and tight sands; nevertheless, the available fracturing fleet is not as technologically advanced as those utilized in the USA for shale gas exploitation.

Furthermore, the service companies demonstrated their global ability to provide equipment and trained human resources, and also their willingness to bring the latest technology to Pakistan, provided that a reasonable amount of business (i.e., 8-10 wells per year with binding contracts with operators for a specific field development) is offered by E&P companies. It must be noted that the carrying cost of hydraulic fracturing technology is very high and, therefore, service companies are hesitant to bring additional equipment and manpower for limited business. A large part of equipment cost is related to mobilization and demobilization, and that is spread over a bulk volume of work. Global service providers, who possess the requisite technology and skilled manpower, are willing to operate in Pakistan subject to investment and business opportunity.
DRILLING RIGS

Currently, there are 48 drilling rigs available in Pakistan with varying capacities. Service and drilling companies own a majority of these drilling rigs and some of these are owned by E&P companies. Concerns were raised over the lack of modern rigs that will be required to drill to the depths (3,000 m - 4,000 m) of shale in Pakistan.

Below lists all the available rigs in Pakistan. These rigs can be categorized as below:

- Operational;
- Ready Stacked; and
- Cold Stacked.

Operational rigs are those rigs that are currently drilling a well. A ready stacked rig is typically mostly crewed, actively marketed, and standing by ready for work if a contract can be obtained. Routine rig maintenance is continued, and daily costs may be modestly reduced but are typically similar to levels incurred in drilling mode. On the other hand, a cold stacked rig is a cost reduction step taken when a rig’s contracting prospects look bleak or available contract terms do not justify an adequate return on the investment needed to make the unit work ready (e.g., repairs or refurbishment).

Currently, all the operational rigs in Pakistan are engaged in some level of activity, and the rigs owned by service companies are also contracted to the operators (on 1 to 3 year contracts). Table 3. Thus, if these operators do not engage in exploring shale, the rigs will not be available. There might be a need to import rigs to fill the gap. As pointed out earlier, constant production from shale formations requires constant drilling in the field; thus, dedicated rigs will be required if fast exploration of shale plays is desired.

Other equipment used for shale gas projects such as logging while drilling (LWD), measurement while drilling (MWD), coil tubing, and filtration plants are available in Pakistan (as these are now also used in conventional wells). Subject to increased demand, additional equipment can be imported with a lead time of 6 to 12 months for varying categories.

Table 3: Drilling Rigs in Pakistan

<table>
<thead>
<tr>
<th>Company</th>
<th>Status</th>
<th>Operational</th>
<th>Cold Stacked</th>
<th>Ready Stacked</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>OGDCL</td>
<td>Owned</td>
<td>10</td>
<td></td>
<td></td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>Rental</td>
<td>4</td>
<td></td>
<td></td>
<td>4</td>
</tr>
<tr>
<td>PPL</td>
<td>Owned</td>
<td>1</td>
<td>1</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Rental</td>
<td>6</td>
<td></td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>Dewan</td>
<td>Owned</td>
<td>2</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>POL</td>
<td>Owned</td>
<td>1</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>MPCL</td>
<td>Owned</td>
<td>2</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Rental</td>
<td>1</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>UEPL</td>
<td>Rental</td>
<td>7</td>
<td></td>
<td></td>
<td>7</td>
</tr>
<tr>
<td>MOL</td>
<td>Rental</td>
<td>4</td>
<td></td>
<td></td>
<td>4</td>
</tr>
<tr>
<td>ENI</td>
<td>Rental</td>
<td>2</td>
<td></td>
<td></td>
<td>2</td>
</tr>
</tbody>
</table>
Not all rigs listed above can be used for drilling wells at the required depths. The potential shale that is being targeted is located between 3,000 m and 4,500 m. Similar to a fracturing unit, the rig also requires more hydraulic horsepower (HHP) to drill deeper and longer laterally. Table 4 categorizes the rigs on the basis of HHP.

**Table 4: Hydraulic Horsepower of Rigs in Pakistan**

<table>
<thead>
<tr>
<th>Capacity</th>
<th>1000 HHP</th>
<th>1500 HHP</th>
<th>2000 HHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational</td>
<td>5</td>
<td>8</td>
<td>27</td>
</tr>
<tr>
<td>Ready Stacked</td>
<td>2</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Cold Stacked</td>
<td>3</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>10</strong></td>
<td><strong>10</strong></td>
<td><strong>28</strong></td>
</tr>
</tbody>
</table>

The current availability of equipment in the country is serving the need for conventional wells. Out of the 48 available rigs, 28 are deep drilling rigs, and out of those 28, 1 is ready stacked (Table 4).

The assessment states that it takes about 5-7 weeks for importing a rig, with China being a prime supplier. This time depends on the availability of ready rigs and does not account for the time it takes to build a new one. The cost of a new rig is in the range of $20-25 million and can take up to 6 to 12 months to build.

**Duties and Taxes on Purchase of Equipment:**

Import of Rigs and associated equipment falls in SRO-678(I)/2004 (amended to date), in accordance with SRO 678(I)/2004 dated August, 7, 2004.

**Imported Equipment not manufactured locally:**

Import duties and sales tax are payable @ 5% on the import of equipment not locally manufactured.

**Imported equipment Available Locally:**

The import duty is 10% for items locally manufactured other than wellhead on which import duty is 15%.
Exemption of Duties in Issuance of Corporate Guarantee:

All Rigs and allied equipment and machinery are exempt from the payment of custom duties, sales tax, and income tax upon issuance of Corporate Guarantees valid for two years for an initial period. For that purpose the importer is required to have a recommendation letter along with attested list of the rig, equipment, and machinery from the operator or company duly signed and stamped. The recommendation letter will be addressed to the Collector of Custom. After expiry of corporate guarantee the same rate of import duty becomes applicable.

It takes an average of 3 months to drill a well to a depth of 4,000 m. With additional time of 4 to 6 weeks for transportation within the Southern or Lower Indus region, and 6 to 8 weeks’ time required for transportation from the south to the north, it can be estimated that it would take 6 months to drill and complete a horizontal well. Hence, in a year one rig can drill two wells. If all the deep drilling rigs (including ready stacked) are utilized to develop shale, 56 wells can be drilled in a single year. If such a number is committed and carried out as mentioned above, then services companies will eagerly enter the market and bring the latest technology. Table 5 below lists the number of rigs required to drill the planned wells.

Table 5: Required Rigs for Planned Wells/yr.

<table>
<thead>
<tr>
<th>Planned Wells (Per Year)</th>
<th>Rigs (2000 HHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>30</td>
<td>15</td>
</tr>
<tr>
<td>40</td>
<td>20</td>
</tr>
<tr>
<td>50</td>
<td>25</td>
</tr>
</tbody>
</table>

HYDRAULIC FRACTURING EQUIPMENT AND CHEMICALS

At the time of this assessment, only one service company – Schlumberger – has a frack fleet (18,000 - 20,000 HHP) in Pakistan, which has a high carrying cost due to the limited business of frack jobs. This frack fleet was brought in 2012 and is a new one. The same was used to frack lateral and horizontal wells for operating companies in Pakistan like Eni and OMV. Shale gas projects cannot be completed without stimulation technology (hydraulic fracturing) and there is a need to develop the equipment base in Pakistan for this technology and at affordable prices (current frack price: $500,000 per stage). Interaction with Sprint Oil & Gas Services indicates that they will be acquiring two fracturing units by end of June, 2015 and will be ready for business in Pakistan by the end of year 2015 and start of year 2016. This might help reduce the cost of fracturing per stage.

5 The horsepower of the fracturing fleet depends on the depth of the well. 18,000-20,000 HHP is required to frack a 3000-4000m deep well.
The hydraulic fracturing process requires an array of specialized equipment and materials. Figure 6 above displays the typical equipment necessary to carry out a fracturing job. The equipment required to carry out a hydraulic fracturing treatment includes:

- **Fluid Storage Tanks**: used for water storage;
- **Frac Blenders**: contains a centrifugal pump, in which sand, water, and chemicals are mixed and then sent to the pumps;
- **Sand Storage Units**: specialized units that are loaded with sand (or proppant) that is then off-loaded during the frack job into the blender;
- **Frac Pumpers**: Triplex and quintuplex pumper trucks that create the pressure required to open up the fractures in the formation;
- **Data Monitoring Truck**: During the fracture treatment, data is collected from various units and sent to the monitoring truck. The data measured includes the fluid rate coming from the storage tanks, slurry rate being delivered to the high-pressure pumps, wellhead treatment pressure, density of the slurry, sand concentration, chemical rate, etc.

Other auxiliary equipment may be used, depending on the design of the frack job.

**CHEMICALS AND PROPPANTS**

Fracturing fluid is made up of 90% water, 9.5% sand, and 0.5% chemicals. These chemicals are largely found in common household products like cosmetics and cleaning supplies.

The “Table 6 lists the common chemicals that are used for fracturing fluids. These chemicals can be easily manufactured in Pakistan if there is a demand for them. For example, guar gum has been cultivated in northwestern India and Pakistan for at least several centuries. India has an 80% share in the international market for guar gum, while Pakistan has the remaining 20%. In 2011, guar emerged as India’s largest agricultural export to the United States, with sales of
$915 million, according to a recent USA Foreign Agricultural Service report. According to reports, Pakistan has also exported guar at a record high of $152 million in 2011-12 before coming down to $139 million in subsequent years. Being a local product, it should not cost as much as it does in the USA.

Service companies have claimed that most of the chemicals are currently imported from abroad. The chemical manufacturing industry can reap the benefits if shale plays are explored and exploited.

Table 6: Common Fracturing Fluid Ingredients

<table>
<thead>
<tr>
<th>Compound</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acids</td>
<td>Help dissolve minerals and initiates fissures in rock (pre-fracture)</td>
</tr>
<tr>
<td>Sodium Chloride</td>
<td>Allows a delayed breakdown of the gel polymer chains</td>
</tr>
<tr>
<td>Polycrylamide</td>
<td>Minimizes the friction between fluid and pipe</td>
</tr>
<tr>
<td>Ethylene Glycol</td>
<td>Prevents scale deposits in the pipe</td>
</tr>
<tr>
<td>Borate Salts</td>
<td>Maintains fluid viscosity as temperature increases</td>
</tr>
<tr>
<td>Sodium/Potassium Carbonate</td>
<td>Maintains effectiveness of other components, such as cross-linkers</td>
</tr>
<tr>
<td>Glutaraldehyde</td>
<td>Eliminates bacteria in the water</td>
</tr>
<tr>
<td>Guar Gum</td>
<td>Thickens the water to suspend the sand</td>
</tr>
<tr>
<td>Citric Acid</td>
<td>Prevents precipitation of metal oxides</td>
</tr>
<tr>
<td>Isopropanol</td>
<td>Used to increase the viscosity of the fracture fluid</td>
</tr>
</tbody>
</table>

The “propping” agent, typically frack sand, is high purity quartz sand with very durable and very round grains. It is a crush-resistant material that is an essential part of hydraulic fracturing. The purpose of the propping agent is to keep the walls of the fracture apart so that a conductive pathway to the wellbore is retained after pumping has stopped and the fracturing fluid has leaked off. There are basically three classes of proppants: Sand, Resin Coated Sand (RCS), and Ceramics (with prices increasing in the same order).

In the USA, St. Peter Sandstone in the Midwest is a primary source of silica. The average price for frack sand reported by the U.S. Geological Survey in 2011 was $54.83 per ton. This is yet again an industry that does not exist in Pakistan. Currently, all sand is being imported from the UAE and is added to the bill of hydraulic fracturing.

TRAINED LABOR

Especial expertise is required for two different phases for shale gas projects: the exploration phase and the exploitation (i.e., drilling and production) phase. The exploration phase expertise mainly includes the following:

- Shale gas/oil specific well log interpretation/petrophysics

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6 An Analysis of Guar Crop in India
- Shale gas specific core and cuttings’ analyses
- Geophysical attribute analysis used in shale gas/oil exploration
- Geomechanical modeling
- Petroleum system modeling/unconventional reservoir modeling, petroleum kinetic modeling, migration pathways etc.
- Shale gas/oil well and field planning and use of GIS
- Geosteering
- Fracture network modeling
- Microseismic data acquisition and interpretation

The operating companies working in Pakistan are in the process of developing this expertise through training and pilot programs, and these operators are on a steep learning curve. Service companies having experience in these domains are also a major source of capacity building.

Regarding the exploitation phase, as mentioned earlier in this report, horizontal drilling and fracturing technology is presently being utilized in Pakistan; however, it is yet to be applied to shale formations.

Multinational service companies claim to be equipped with skilled manpower for drilling and fracturing jobs at a global level. Based on the requirement and volume of business, the international expertise can be brought into the country. Furthermore, these companies have global training centers for each service they offer and are quick to adapt to the demand for skilled labor. During the assessment, ENI and Schlumberger demonstrated their international competencies and shared details about the shale gas specific trainings they offer globally. In case of Schlumberger, they have multiple training centers around the globe offering courses for both conventional as well unconventional areas to human resources of the E&P industry. In terms of developing expertise even the national E&P companies have recognized the need to train their professionals for shale gas and they are doing so by sending the experts to the US for developing the required skills. In addition, service companies such as Weatherford are imparting training locally.

Furthermore, local E&P companies would continue to rely on service providers to execute horizontal drilling and fracturing jobs.

For the purpose of this study, direct roles and services have been identified that are considered critical to developing shale resources. The categories for these roles include:

- Drilling and completions
- Hydraulic fracturing
- Petroleum engineering and geosciences
- Planning approvals
- Health, safety, and environmental monitoring

By unlocking the shale resources, these roles are critical to opening up the wider supply chain opportunities (e.g., rigs, auxiliary equipment, cement, proppant, and chemicals).
Table 7 lists the skills required to develop shale plays in Pakistan. Most companies already have labor under these categories for conventional reserves. Wherever additional trainings are required for which international expertise and training courses will be relied upon.

**Table 7: Human Resource Requirement for Development of Shale Gas**

<table>
<thead>
<tr>
<th>Skills Category</th>
<th>Functions and Services</th>
<th>Roles</th>
</tr>
</thead>
</table>
| Drilling and Completions | • Drilling services  
• Casing and cement services  
• Drilling waste disposal  
• Logistics management | • Crews (drilling, casing, and cement, and coiled tubing) including engineering services, front-line supervisors and project management, derrick and equipment operators, apprentices and laborers (roustabouts)  
• Mud loggers, geologists, or geotechnical engineers  
• Drill cutting and waste disposal vehicle drivers |
| Hydraulic fracturing | • Pressure pumping equipment and perforation set-up and operations  
• Chemical and proppant supply  
• Mixing and pumping fracturing fluid  
• Waste management  
• Micro seismic service | • Fracturing and perforating crews including:  
• Engineering services, front line supervisors  
• Project management, high pressure pump operators  
• Perforating charge operators, blender operators  
• Apprentices and laborers (roustabouts)  
• Waste water treatment and disposal vehicle drivers  
• Crane and tower operators |
| Petroleum engineering and geosciences (including environmental consultants) | • Evaluation and monitoring of field performance  
• 2D and 3D seismic modeling  
• Coring and field lab sample analysis | • Petroleum engineers  
• Geologists and geophysicists  
• Lab technicians  
• Seismic crews (supervisors, equipment operators, observers and apprentices) |
| Planning approvals, health, safety and environmental monitoring | • Review of planning applications from operators to permit the surface operations required to explore and extract shale gas  
• Monitoring of compliance with safety risk management  
• Requirements (e.g., well integrity)  
• Advising local authorities on the scope of an Environmental Impact Assessment | • Local Planning Authorities  
• HSE Well Examiners  
• Environmental risk and impact assessment advisors |
| Operations management | • Site and facilities management  
• Security services  
• Fuel  
• Waste disposal/cleaning  
• Equipment inspections and maintenance | • Operations and maintenance technicians  
• Security guards  
• Fuel truck drivers  
• Waste disposal vehicle drivers  
• Trades services and apprentices (carpenter, electrician, plumber, construction laborers) |
| Construction | • Pad site grading | • Excavation heavy equipment operators |

9 Taken from EY Report Supply Chain and Skills Requirements for Shale Gas April 2014.
<table>
<thead>
<tr>
<th>Skills Category</th>
<th>Functions and Services</th>
<th>Roles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction of gathering facilities and pipelines</td>
<td>Engineering (civil, mechanical, chemical, electrical)</td>
<td></td>
</tr>
<tr>
<td>Construction of gathering facilities and pipelines</td>
<td>Project management</td>
<td></td>
</tr>
<tr>
<td>Construction of gathering facilities and pipelines</td>
<td>Trades services and apprentices (carpenter, electrician, plumber, construction laborers)</td>
<td></td>
</tr>
<tr>
<td>Transport of construction materials</td>
<td>Field services support: drilling engineering, well completions, geological support, health and safety, approvals, production and site planning, procurement and PR, and community relations</td>
<td></td>
</tr>
<tr>
<td>Engineering (civil, mechanical, chemical, electrical)</td>
<td>Field services support: drilling engineering, well completions, geological support, health and safety, approvals, production and site planning, procurement and PR, and community relations</td>
<td></td>
</tr>
<tr>
<td>Project management</td>
<td>Field services support: drilling engineering, well completions, geological support, health and safety, approvals, production and site planning, procurement and PR, and community relations</td>
<td></td>
</tr>
<tr>
<td>Trades services and apprentices (carpenter, electrician, plumber, construction laborers)</td>
<td>Field services support: drilling engineering, well completions, geological support, health and safety, approvals, production and site planning, procurement and PR, and community relations</td>
<td></td>
</tr>
<tr>
<td>Field services support including drilling, well completions, geology, health and safety, environmental monitoring, production planning, procurement, community relations, finance and administrative</td>
<td>Finance and administrative professionals</td>
<td></td>
</tr>
<tr>
<td>Field services support including drilling, well completions, geology, health and safety, environmental monitoring, production planning, procurement, community relations, finance and administrative</td>
<td>Marketing and sales professionals</td>
<td></td>
</tr>
</tbody>
</table>
5. INFRASTRUCTURE ASSESSMENT

This study is focused on roughly 271,795 km² of the Middle and Lower Indus Basin. Development of Pakistan’s shale gas resources will require expansion of infrastructure assets including pipeline facilities, gas processing plants, and additional equipment and technology.

The existing infrastructure is adequate to cater for the current operations as well as for near future requirements. Shale gas/oil exploitation operations are at least 4–5 years away and hence there is sufficient time to develop additional infrastructure. To develop shale gas to a commercial entity similar to that in the USA, virtually all portions of the shale gas value chain will require upgradation. These needs are related to bringing shale gas resources to market through production, gathering, midstream processing, and long distance transmission. Natural Gas Liquids (NGLs) will also be extracted from gas at the field facilities.

This section provides an overview of the following key infrastructure areas associated with the development of shale gas/oil resources:

- Roads
- Pipelines
- Water

ROADS
To unlock the value of shale gas, wells need to be drilled and brought into operation. Drilling activities increase the local demand for concrete, steel, and site services, such as, excavation, hauling, and construction of drilling pads. All of these demands strain the facilities that produce, distribute, and transport these goods and services. Unconventional drilling also requires large quantities of water, sand, and equipment, which need to be transported into areas that are often remote. This, in turn, increases the burden on the region’s road infrastructure.

The road systems in shale plays often require significant upgrading, which the gas industry generally upgrades voluntarily as a necessary cost of doing business. These “lease” or dirt roads connect to main roads or highways available in the area. On the other hand, district roads and highways are an entity of district governments and the National Highway Authority (NHA), respectively. Districts having exploration and production concessions already have lease roads that are connected to local roads and highways, but these might be insufficient to support the supply of goods and services related to shale activity.

For an efficient transportation to the shale gas exploitation sites, the adequate axle load limits implementation as part of the road management plan is very important. The high levels of traffic activity from water trucks, sand trucks, pumping equipment, and others may be a problem for the roads that are not designed for the extra heavy loads. Load control will not only help reduce road maintenance costs but also encourage importers to introduce prime mover and trailer combinations. This can radically change the truck transport business and container transportation will be encouraged.

In the US railroads are also being used to transport huge quantities of shale gas exploitation related materials and equipment.

PIPELINES
The natural gas transmission and distribution pipeline network can be used for the produced unconventional gas. This requires capital outlays for gathering lines (typically 6 inch to 20 inch diameter pipelines) to take the raw natural gas to processing facilities. Water and condensate
are typically removed from the raw natural gas near the wellhead. Gathering lines then carry the remaining natural gas to processing facilities to remove other constituents to match the specifications.

In Pakistan, gathering lines are constructed by E&P companies to take the natural gas to gas processing facilities, which are also built by the E&P companies. The gas is then carried to local pipelines, which are connected to the main transmission pipeline. The estimated cost as indicated by E&P companies for ancillary pipelines (from field to main pipeline) is about $24,000 per kilometer.

Transmission pipelines (typically 12 inch to 36 inch diameter) take the processed natural gas from the processing facilities to the main transmission line from where they tie into existing local distribution networks.

Gas pipeline infrastructure in Pakistan is operated by two utility companies:

- Sui Southern Gas Company Limited (SSGCL), and
- Sui Northern Gas Pipeline Limited (SNGPL).

The SSGCL transmission system extends from Sui in Balochistan to Karachi in Sindh and comprises of over 3,220 km of high pressure pipelines ranging in diameter from 12 inches to 24 inches.

The SNGPL transmission system extends from Sui in Balochistan to Peshawar in Khyber Pakhtunkhwa (KPK) and comprises of over 7,733 km of Transmission System (including main lines and loop lines).

Although these localized transmission and distribution networks are well established, they will need to adjust to the natural gas demand (for heat, power, and transportation). Currently, according to the Oil and Gas Regulatory Authority (OGRA), the supply-demand gap stands at around 2,000 million cubic feet per day (MMCFD) (Table 8).

<table>
<thead>
<tr>
<th>Available Capacity (MMCFD)</th>
<th>Max. Flow Passed (MMCFD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indus Left Bank Pipeline System (SSGC)</td>
<td>645</td>
</tr>
<tr>
<td>Indus Right Bank Pipeline System (SSGC)</td>
<td>640</td>
</tr>
<tr>
<td>Quetta Pipeline System (SSGC)</td>
<td>174</td>
</tr>
<tr>
<td>Transmission Network Contracted (For SNGPL by SSGC)</td>
<td>245</td>
</tr>
<tr>
<td>SNGPL Transmission Network</td>
<td>4,148</td>
</tr>
<tr>
<td>Total</td>
<td>5,852</td>
</tr>
</tbody>
</table>

**WATER**

Hydraulic fracturing requires large amount of water. Hence, the availability of water is a major factor in the development of shale gas projects. For one well with multi-stage frac jobs, 3-8 million gallons of water is required. The amount of water required to complete a well varies from well to well and play to play, making estimates of water demands for shale development uncertain for most unexplored plays around the world. The variation in water requirements depends on the geology and the well characteristics. For example, the number of horizontal segments hydraulically fractured, as well as the production type, depth and length of the well, determine the amount of water required. In turn, these well characteristics vary based on the
formation geology. The shale play’s depth, thickness, and porosity can also influence water requirements.

Figure 6 shows how water requirement varies in different shale plays in the USA. Shales in Pakistan are similar to Haynesville (water requirement 6 million US gallons), but deeper water requirement throughout the study is assumed to be 8 million US gallons.

![Figure 6: Average Water Use by Major Shale Plays in the USA](image)

The selection of water supply option for hydraulic fracturing will depend on the amount of water that will be required, in aggregate, for the broader, long-term and area-wide development program anticipated. Water sources will need to be appropriate for the forecasted pace and level of development anticipated. Water for hydraulic fracturing can be sourced from surface water, groundwater (fresh and saline/brackish), and wastewater streams or sea water through recycling facilities.
The choice will also depend upon volume and water quality requirements, regulatory and physical availability, competing uses, and characteristics of the formation to be fractured (including water quality and compatibility considerations). If possible, wastewater from other industrial facilities should be considered first, followed by ground and surface water sources (with the preference of non-potable sources over potable sources), with the least desirable (at least for long-term, large scale development) being municipal water supplies. However, this will depend on local conditions and the availability of ground and surface water resources in proximity to planned operations. Importantly, not all options may be available for all situations, and the order of preferences can vary from area to area. Moreover, for water sources such as industrial wastewater, power plant cooling water, or recycled flowback water and/or produced water, additional treatment may be required prior to use for fracturing, which may not be possible or feasible and may not deliver the results necessary to assure project success.

SURFACE AND GROUNDWATER IN PAKISTAN

Pakistan lies in an arid and semi-arid climate zone and Pakistan is one of the very few countries in the world whose water resources entirely depend upon one river system, i.e., the Indus River System.

Of the total available annual flow of 138 million acre-feet (MAF\textsuperscript{10}) in the Indus Basin, 105 MAF is already being used through 19 barrages with 45 canal systems above and below rim stations. Average annual flow below the Kotri Barrage reaching the sea is 33 MAF; this is not enough for the coastal region and there is already environmental degradation. The months of peak-flow are June to August during the monsoon season. The flow during the summer is 84% and during winter season is 16%. The alluvial plains of Pakistan comprise of extensive unconfined aquifer, with a potential of over 50 MAF, which is being exploited to an extent of about 38 MAF by more than 562,000 private and 10,000 public tube wells. In Balochistan (outside the Indus Basin), out of a total available potential of about 0.9 MAF of groundwater, more than 0.5 MAF are already being utilized, thereby leaving a balance of about 0.4 MAF that can still be utilized, though some aquifers are already over exploited. With water scarcity E&P companies

\textsuperscript{10} \text{1 MAF = 326 billion US gal = 1.23 × 10^{12} liters.}
may have to rely on alternate solutions including but not limiting to use of treated water such as desalinated water. Figure 8 displays sample wells along River Indus.

**Figure 8: Pakistan River System with Barrage Outflow with Wells**

![Pakistan River System Map With Barrage outflows of 1st July 2015](image)

The fresh groundwater in the Indus Plains is found to be underlain with saline groundwater, the layers of fresh groundwater being thick near the rivers and other sources of recharge, and of almost negligible thickness in areas where recharge is small, in comparison to current groundwater pumping. Fresh water is, therefore, found up to considerable depths in wide belts paralleling the major river and around some of the recently abandoned river courses in the meander flood plain. A further and very significant recent addition to the total groundwater complex is barrage-commanded irrigation. During the past 100 years, seepage from canals and deep percolation from irrigated fields have made substantial contributions to the groundwater.

In many of the irrigated and non-irrigated (rain only) areas of Punjab and Balochistan, groundwater extraction has exceeded annual natural recharge. From the perspective of large scale shale gas development and the huge quantities required for hydraulic fracturing, water usage regulations are proposed in detail, which will be covered in the subsequent Milestone report.
The quality of groundwater ranges from fresh (salinity less than 1000 mg/l TDS\(^{11}\)) near the major rivers to highly saline farther away, with salinity more than 3000 mg/l TDS. The general distribution of fresh and saline groundwater in the country is not well-known as studies available by Pakistan Water and Power Development Authority (WAPDA) are dated from 1980s and early 2000s. Figure 9, illustrates the salinity distribution around the Indus Basin.

**Figure 9: Groundwater Quality in Pakistan (2001)**

Many companies in the USA use freshwater for drilling and fracturing, though brackish and recycled water offer significant opportunities to reduce freshwater demands. Information on the proportion of brackish, recycled, or reused water used as a substitute for freshwater in the United States is scarce. Available data indicates that in 2011 brackish water use by the oil and gas industry in Texas ranged between 0 and 80 percent, and recycled water between 0 and 20 percent of the total water demand, depending on the location. Additionally, although nearly all fracturing treatments use water, alternatives exist including liquefied petroleum gas and CO\(_2\) fracture treatments. One of the limitations to recycling and reusing water is that the amount of flow-back returned to the surface varies between and within plays. However, new projects are underway to support increased recycling and reuse to reduce freshwater withdrawals and consumption by the oil and gas sector.

The selected shale districts, which are located along the main Indus River around the abandoned channels and near the barrage command irrigation, would have greater chances of exploiting fresh water. Eastern parts of R. Y. Khan, Ghotki, Sukkur, Khairpur, and Sanghar fall in desert area and may have increasingly saline groundwater towards the east. However, useable water is anticipated in the central parts of Khairpur and Sanghar Districts because of the Nara canal. Similarly, the arid region of D. G. Khan and Rajanpur Districts, between the mountain front and the agricultural belt, would have a paucity of the groundwater.

**Ground Water Availability**

The following map (Figure 10) shows the groundwater availability for drilling and hydraulic fracturing for the shale gas project differ by regions. The large scale map is available for reference in the Annexure.

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\(^{11}\) TDS: Total Dissolved Solids are the total amount of mobile charged ions, including minerals, salts or metals dissolved in a given volume of water.
It is very difficult to place a quantitative value on the amount of water available in Pakistan as detailed water availability and quality reports from prospective districts can be purchased from private environmental companies. The hydrological investigation information discussed below was provided by Water and Power Development Authority (WAPDA).

**Hydrogeological Investigation in Middle Indus Basin:**

**Dera Ghazi Khan (DGK), Rajanpur, R. Y. Khan (RYK) and Ghotki Districts**

Fresh groundwater (FGW) having TDS content from 450 to 1100 mg/l can be expected up to a depth of 500 ft. (150 m). FGW is found in a belt adjoining the right bank of River Indus from Shadan Lund to Mithan Kot. The maximum width of the belt is 14 miles (~22 km) near village Ghati. Another patch of FGW is found west of Retral in the northern part. In the northwestern part, the quality of groundwater improves with depth. Highly saline groundwater is found in the southern part of Dera Ghazi Khan Canal command from Rajanpur to Kashmore in Sindh; the salinity of groundwater increases with depth. Groundwater of 9,000 to 17,000 mg/l TDS has been found in this area, though pockets of FGW are randomly found at very shallow depths.

Eastern part of the DGK and Rajanpur Districts overlie the western flank of the Sulaiman foredeep, wherein the Siwalik strata dips steeply towards the east. Rodho and Dhodak fields fall within the DGK District; and for Rodho the water, through pipeline, is brought from Taunsa located on the right bank of River Indus at a distance of about 15 km.

The water table in RYK is deeper than the Ghotki District. A broader belt of non-saline surface indicates that more than 50% of RYK and the Ghotki Districts, falling in the west, would...
provide better quality ground water. Even the percolating surface water (floods and rains) would not increase the salinity of the groundwater.

**Musakhel, Loralai, Barkhan and Kohlu Districts**

The Districts are located north of the prolific gas producing fields of Sui and Pirkoh located in the Sulaiman Lobe further south.

There is no surface water source around Sui; nor does the possibility of ground water exist. A pumping station was established near Kashmore where the water wells are the source, and the main ground water recharge is from the Pat Feeder canal. For the Pirkoh gas field the water is reportedly pumped from a stream named Pathar Nala, and the drinking water is obtained from a spring located in Dera Bugti.

**Hydrogeological Investigation in Lower Indus Basin**

In Lower Indus Basin (Sindh), the River Indus is the main source of fresh groundwater mainly on its left bank. The fresh groundwater on the right side of the Indus lies in a narrow strip. The depth of fresh groundwater decreases with distance from the river. In Sindh, 28% of the area has fresh groundwater suitable for drinking and irrigation purposes. There is a very wide range of groundwater quality distribution in Sindh (250 to 3550 mg/l). The general standard for drinking water is <500 mg/l. The native groundwater of the Lower Indus Plain (south of Hyderabad) is very saline being of marine origin.

During the course of hydrogeological investigations carried out for the Lower Indus Project of WAPDA, a number of bore holes 100 to 1,300 feet in depth, were drilled in Guddu, Sukkur, and Kotri Barrage commands to determine the quality of groundwater and its horizontal and vertical variation.

The general pattern of groundwater distribution in the Lower Indus Plains is one of good quality water immediately adjacent to the river with increasing salinity away from the river. A lesser quantity of good quality water is available on the right bank of the river than on the left. This is due to the proximity of limestone hills on the right bank and to the poor aquifers associated with piedmont plains. Another feature of importance is the complete absence of usable groundwater in the deltaic area, south of Hyderabad, except in some shallow pockets in the fairly recently abandoned river beds of the Gaja command. Some of the most saline groundwater of the region is found in the delta where the water samples with salinities twice as high as the sea-water have been obtained. Throughout the region the salinity of groundwater increases with depth and no case has been recorded where saline water overlies fresh water. A brief discussion of the groundwater quality in the commands of Guddu, Sukkur and Kotri Barrages is given below:

**Guddu Barrage:** Bore holes drilled on the right bank of Indus River showed good quality water at shallow depths and that too near the river. As the distance increases away from the river, the water quality even at shallower depths worsens along with deeper bad quality water. On the left side of the river, most of the area of Ghotki canal command is fresh.

**Sukkur Barrage:** The behavior of water quality is not altogether unexpected because of the reason of the proximity of limestone hills. Good quality groundwater is available near the Indus River and that too at a shallow depth. On the left bank of Indus River in Sukkur Command the water quality is good throughout. Water quality is good throughout up to 350 feet depth generally but it worsens with distance away from the river. The Indus River acts as the main source of recharge.

**Kotri Command:** This is deltaic area and groundwater quality is of extremely poor quality as at some places the TDS content is twice the TDS of sea water. The reason for this high salinity of groundwater is the presence of high water tables with concentration of salts because of high rates of evaporation. The only pockets of fresh water, in the Kotri command, are found
around the recently abandoned flood courses of Gaja River. The Lower Indus alluvium is saturated with groundwater, often to within a few feet of ground surface.

**Water Stress in Pakistan**

To further understand the water resource situation in Pakistan, Aqueduct Water Risk Atlas by World Resources Institute (WRI) was studied. Aqueduct\(^{12}\) highlights Pakistan (see Figure 11) as one of the world's 36 most water-stressed countries (ranked 31\(^{st}\)).

![Image](https://example.com/water-stress-map.png)

**Figure 11: Water Stress by Country**

WRI's estimates show the average level of exposure to five of Aqueduct’s physical water quantity risk indicators for countries and major river basins worldwide.

These indicators include:

- **Baseline water stress:** the ratio of total annual water withdrawals to total available annual renewable supply. Higher values may indicate more competition among users and greater depletion of water resources.
- **Inter-annual variability:** the variation in water supply between years.
- **Seasonal variability:** the variation in water supply between months of the year.
- **Flood occurrence:** the number of floods recorded from 1985 to 2011.
- **Drought severity:** the average length of droughts times the dryness of the droughts from 1901 to 2008.

WRI calculate aggregated water risk score for each indicator to a scale of 0–5. Then it is combined using a weighted average for overall water risk score. Pakistan and Indus Basin scores for all indicators (color coded according to Figure 11 above) are shown in Table 9.

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\(^{12}\) Study that ranks countries and rivers basins worldwide based on their exposure water-related risks. Specifically, it provides national and basin-level scores derived from more localized water-risk scores from the Aqueduct Water Risk Atlas.
Table 9: Pakistan’s Score against WRI Indicators

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Score by Sector</th>
<th>Score</th>
<th>Agricultural</th>
<th>Domestic</th>
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<td>3.9</td>
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<tr>
<td>Drought Severity</td>
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<td>2.5</td>
<td>2.5</td>
<td>2.4</td>
<td>2.4</td>
</tr>
</tbody>
</table>

From the shale gas global development assessment by WRI, the global results provide useful information on the distribution of water resources across shale plays in each country. For example, the distribution of baseline water stress over shale plays (Figure 12) shows the extent to which national shale resources are exposed to different levels of competition and depletion of water resources. Understanding this type of information can help minimize environmental impacts, evaluate business risks, and develop effective sustainable water sourcing strategies. The water resource situation in Pakistan demands alternate water sources and technologies that do not use water should be looked into for long-term large scale shale development. When investigating potential options for securing water supplies to support hydraulic fracturing operations, awareness of competing water needs, water management issues, and the full range of permitting and regulatory requirements in a region is critical.
Figure 12: Distribution of Baseline Water Stress across Shale Plays in 20 Countries with the Largest Technically Recoverable Shale Gas Resources

Desalinated Water

Water scarcity can and will be a hindrance to commercial scale shale exploitation and it is advised that alternate sources to fresh water should be considered from the start. To fulfill the criteria for an alternate source, seawater was considered and its economic feasibility was estimated, as seawater will not be used directly and desalination will be required.

Desalination is increasingly used worldwide to supplement (or replace) existing conventional water sources in water scarce areas. Currently, less than 3% of the world’s total water requirements are met by desalination. There are a number of commercially available desalination processes, including the following:
- Multiple-effect distillation (MED)
- Multi-stage flash distillation (MSF)
- Vapor compression (VC)
- Reverse osmosis (RO) and
- Electro-dialysis (ED)

The most widely installed process is RO, followed closely by MSF.

The cost of water produced by desalination varies greatly depending on various factors:

- **Quality of Feedwater.** The quality of feedwater is a critical design factor. Low TDS concentration in feedwater (e.g., brackish water) requires less energy for treatment compared to high TDS feedwater (seawater). In this study, seawater, which requires more energy, will be used.

- **Plant Capacity.** Plant capacity is an important design factor. Large capacity plants require high initial capital investment. For the purposes of our study medium capacity plant (4,800-15,000 m³/day) and large capacity plants (>30,000 m³/day) are compared. It is important to note that even though large capacity plants have high capital costs, the operational cost will be significantly less.

- **Location.** Cost of land and proximity to water source. The plant for this study will be located on the coast thus piping and trucking will not be an issue. But transporting the water to the well site will be considered.

- **Construction costs (direct and indirect).**
- **Operation and maintenance (O&M) costs (fixed and variable).**

Normally reliable initial estimates of plant capital costs and O&M are based on databases of previous cost estimates produced within the country. If this option is not available (as in the case of this study), then the existing and planned plant cost data may be used as a starting point. To date, a few international cost databases have been compiled. Those currently available include work by Ettouney\(^{13}\), Leitner\(^{14}\) and Park et al.\(^{15}\) and these have been studied.

Additionally, the location of a plant is often believed to have an impact on operating and capital costs. Clearly, locating a plant in countries where labor and land costs are low often produces an end product significantly cheaper than in a country where these costs are high. However, a surprising observation based on a small desalting cost database was made by Park et al. that plant location had very little observable effect on the cost of water. This implies that cost data from around the world can be applied to any location.

Several models are available for estimating desalination costs. Cost models can be used as an indicator of potential costs for planning a desalination facility. For the purposes of this study, Desalination Economic Evaluation Program (DEEP)\(^{16}\) was used. The International Atomic Energy Agency (IAEA) has developed DEEP to perform economic analysis of desalination using nuclear energy in comparison to fossil fuel energy sources. For the purposes of this study the default technical and economical inputs were used, but local fuel cost (part of energy cost)


\(^{16}\) International Atomic Energy Agency. "Desalination Economic Evaluation Program (DEEP-5.1)." Vienna, 2014
and water transport cost to Middle-Lower Indus Basin were considered. Other assumptions and inputs are as follows:

- Desalination process of reverse osmosis (commonly used)
- Membrane pressure at 75 bar (for seawater the range is between 40-82 bar)
- Fuel source is gas at $5.63 /MMBTU (Oil and Gas Regulatory Authority’s notification No. S.R.O. 01(I)/2013 for Captive Power)
- Feedwater salinity = 35,000 ppm\(^{17}\) and water output salinity = 210 ppm\(^{18}\)
- Combined-cycle power plant (gas and a steam turbine)
- Tax rate = 35% and Equity expected return = 6%, WACC = 5%
- Lifetime of the plant = 20 years
- Two capacity scenarios were run as even though the Capex for higher capacity is more, the running cost is less which reduces the OPEX and thus the water cost to the consumer.

The total water cost for two different capacities are as following:

- Desalination Plant with 8,000 m\(^3\)/day (i.e., 2113376 US Gallon/day) capacity, the modeled Total Water Cost is $0.0034 /US Gallon (See Figure 13 below)
- Desalination Plant with 100,000 m\(^3\)/d (i.e. 26417205 US Gallon/day) capacity, the modeled Total Water Cost is $0.0030 /US Gallon (See Figure 14 below)

\(^{17}\) Typical seawater salinity varies between 35-40,000 ppm and for Arabian Sea it varies between 35-36,000 ppm.
\(^{18}\) Range taken from SPE paper 141448
Desalination plant

Type: RO
Total Capacity: 8000 m³/d
Feed Salinity: 35000 ppm
Combined Availability: 77%
Water Production: 2.63 M m³/yr
Power Lost: 0.0 MW(e)
Power Used for desalination: 1 MW(e)

Capital Costs of Desalination Plant

<table>
<thead>
<tr>
<th></th>
<th>MSF</th>
<th>RO</th>
<th>Total (M$)</th>
<th>Specific ($/m³ d)</th>
<th>Share</th>
</tr>
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<td>Construction Cost</td>
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<td>9</td>
<td>1,177</td>
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<td>Intermediate loop cost</td>
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</tr>
<tr>
<td>Backup Heat Source</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Infall/Outfall costs</td>
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Operating Costs of Desalination Plant

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<th>Total (M$)</th>
<th>Specific ($/m³)</th>
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<td></td>
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<td><strong>Total water cost</strong></td>
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Figure 13: Desalination Plant @8,000 m³/d
Desalination plant

<table>
<thead>
<tr>
<th>Type</th>
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<tbody>
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<td>Power Used for desalination</td>
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**Capital Costs of Desalination Plant**

<table>
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<th>RO</th>
<th>Total (M$)</th>
<th>Specific ($/m³ d)</th>
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<td>118</td>
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**Operating Costs of Desalination Plant**

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<td>Heat cost</td>
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<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Electricity cost</td>
<td>-</td>
<td>6.5</td>
<td>6.5</td>
<td>0.20</td>
<td>43%</td>
</tr>
<tr>
<td>Purchased electricity cost</td>
<td>-</td>
<td>1.5</td>
<td>1.5</td>
<td>0.05</td>
<td>10%</td>
</tr>
<tr>
<td><strong>Total Energy Costs</strong></td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>0.24</td>
<td>53%</td>
</tr>
<tr>
<td>Operation and Maintenance Costs</td>
<td>-</td>
<td>-</td>
<td>0.20</td>
<td>0.01</td>
<td>1%</td>
</tr>
<tr>
<td>Management cost</td>
<td>-</td>
<td>-</td>
<td>0.20</td>
<td>0.01</td>
<td>1%</td>
</tr>
<tr>
<td>Labour cost</td>
<td>-</td>
<td>-</td>
<td>0.68</td>
<td>0.02</td>
<td>5%</td>
</tr>
<tr>
<td>Material cost</td>
<td>-</td>
<td>5.43</td>
<td>5.4</td>
<td>0.17</td>
<td>36%</td>
</tr>
<tr>
<td>Insurance cost</td>
<td>-</td>
<td>0.68</td>
<td>0.7</td>
<td>0.02</td>
<td>5%</td>
</tr>
<tr>
<td><strong>Total O&amp;M cost</strong></td>
<td>-</td>
<td>6</td>
<td>7</td>
<td>0.21</td>
<td>47%</td>
</tr>
<tr>
<td><strong>Total Operating Costs</strong></td>
<td>-</td>
<td>14</td>
<td>15</td>
<td>0.46</td>
<td></td>
</tr>
</tbody>
</table>

**Total annual cost** | 26.17 M$ |

Water production cost | 0.797 $/m³ |
Water Transport costs | - $/m³ |
**Total water cost** | 0.797 $/m³ |

Figure 14: Desalination Plant @100,000 m³/d
Table 10 shows the estimated transportation costs via tankers of water from Karachi to different districts in Middle and Lower Indus Basin; the cost breakdown provided is in US$ per US Gallon and US$ per cubic meter (provided by Rasch Private Limited, i.e., Part of Al Haj Enterprises).

**Table 10: Water Transport Cost for Different Districts in Pakistan**

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>Km (return journey)</th>
<th>US $/Gallon</th>
<th>US $/m³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Karachi</td>
<td>Middle Indus Basin</td>
<td>1,200</td>
<td>0.0974</td>
<td>25.47</td>
</tr>
<tr>
<td>Karachi</td>
<td>Badin</td>
<td>504</td>
<td>0.0409</td>
<td>10.70</td>
</tr>
<tr>
<td>Karachi</td>
<td>Thatta</td>
<td>206</td>
<td>0.0167</td>
<td>4.37</td>
</tr>
<tr>
<td>Karachi</td>
<td>Mirpurkhas</td>
<td>462</td>
<td>0.0375</td>
<td>9.81</td>
</tr>
<tr>
<td>Karachi</td>
<td>Khairpur</td>
<td>900</td>
<td>0.0731</td>
<td>19.10</td>
</tr>
</tbody>
</table>

The desalinated water will be cheaper for a shale play closer to Karachi. For the financial model a central point is going to be considered to neutralize extreme values of high and low.

Figure 15 below illustrates the central location for both basins (600 km return trip for Lower Indus Basin and 1200 km for Middle Indus Basin). Depending on the exploration and production activity of shale plays water distribution centers can also be built here that can be connected via water pipelines to the desalination plant and then water is transported from such centers via tankers to specific wells.

![Figure 15: Central Points for Middle and Lower Indus Basin](image)

The overall capital investment cost of a shale project per section with a case using only desalinated water and the wellhead cost impact of it is considered in the next section.
6. DEVELOPMENT WORK PLAN

The majority of the work conducted for the Shale Gas Assessment in the Middle and Lower Indus Basins was focused on establishing a basin-level understanding of the four target formations. Furthermore, as part of the resource assessment, simulation for 10 year production forecasts was performed for 13 wells. Table 11 lists the wells on which simulated production profiling was completed, along with the formations drilled. Out of those 13 wells, 9 wells were in the gas window highlighted, and 7 (highlighted green) out of these 9 wells had recoverable resource with thermal maturity (i.e., recovery factor >1%). These wells were selected as per the following criteria:

- Selected zone to be in gas maturity window
- Complete formation data coverage and well log data quality in the zone of interest
- Geographical distribution throughout the study area
- Continuous Potential Shale Gas Pay Zone Thickness is greater than 20m (where possible)

It is important to note that the wells in Ranikot and Ghazij are not thermally mature and only petrophysical log analyses data had been used. In order to depict as realistic representation as possible the wells are selected at various concentrations of gas-in-place throughout the study area.

Table 11: Selected Wells with Simulated Recovery >1% in Gas Maturity Window (Green)

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation Located</th>
</tr>
</thead>
<tbody>
<tr>
<td>Babar 01</td>
<td>Lower Goru</td>
</tr>
<tr>
<td>Dabbar 01</td>
<td>Ranikot</td>
</tr>
<tr>
<td>Pir Patho 01</td>
<td>Lower Goru</td>
</tr>
<tr>
<td>Raj 01</td>
<td>Lower Goru</td>
</tr>
<tr>
<td>Damiri Re-entry 01</td>
<td>Lower Goru</td>
</tr>
<tr>
<td>Hashim Kher</td>
<td>Lower Goru and Sembar</td>
</tr>
<tr>
<td>Sabzal 01</td>
<td>Ranikot</td>
</tr>
<tr>
<td>Sultan 01</td>
<td>Ghazij</td>
</tr>
<tr>
<td>Suleman 01</td>
<td>Sembar</td>
</tr>
<tr>
<td>Kunri 01A</td>
<td>Ranikot</td>
</tr>
<tr>
<td>Jumman Shah 01</td>
<td>Sembar</td>
</tr>
<tr>
<td>Qadirpur 01</td>
<td>Sembar</td>
</tr>
<tr>
<td>Kadanwari 01</td>
<td>Lower Goru</td>
</tr>
</tbody>
</table>

It is expedient to use the current standards and work practices established in the United States, where work on a number of unconventional shale plays is already in progress. In the USA’s system of privatized operations, there are still regulations that govern environmental

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19 Shale Gas and Oil Resource Assessment Report details the simulated 13 wells production forecast.
and infrastructure requirements to determine well spacing, areas, concessions, etc. For unconventional shale plays in USA, a minimum lease area of 640 acres is known as a section, which is equivalent to one square mile (or 2.59 km²). This lease area unit has also been considered for this study.

In order to accurately and economically develop a full field, there are extensive scientific investments that must be made: seismic evaluation, exploration wells, minimum of triple combo wireline logging or LWD, substantial coring (whole cores preferred), sampling, testing, production analysis, etc. Without this information, which for the most part is the case in this study, educated assumptions based on analogue formations were made.

Naturally, with assumptions being made, there are limitations. These can be mitigated with the use of appropriate tools, such as, geological modeling, mapping, interpolation, statistical inferences made when normalizing data, calibrating, and others. These limitations can also provide some misleading information as to the “producibility” of shale, which may only be calculated through pilot wells with actual perforation and completion. Therefore, realistic expectations need to be set at the onset. Once a certain number of proof-of-concept wells are drilled and tested, a realistic answer can be given.

**WORK PLAN**

This plan can be applied and deployed across the different areas of the basin in each formation on a section-by-section basis. As with all new shale play exploration and development prospects and projects, the best practice is learning what works best in each play, as no shale responds the same.

In shale gas development one of the key parameters is the stimulated reservoir volume (SRV). The SRV can be estimated from microseismic data mapping in the production and development stage of shale gas; however, in the initial stage of pre-drill planning, the frac half-lengths on sides of the vertical and/or horizontal well bore may be used, as illustrated in Figure 16 below, for an average drainage area calculation.

![Figure 16: Drilling and Stimulation Measurements Illustrated for Drainage Area](image)

For instance, Completion Scenario 3 in the above illustration uses a vertical well with a maximum drainage area of 28.18 acres for a shale zone. The Geometry Factor is achieved by
dividing 28.18 by the total unit area to drain, i.e., 640 acres, which in this specific case is 22.7. The Geometry Factor is the number of wells required to drain/deplete one square mile, i.e., ~23.

The work plan discusses four scenarios: three vertical and one horizontal well completion with variable frac half-lengths. Each of these scenarios is simulated to drain a single shale zone within an area of one square mile or 640 acre section.

The details of individually selected zones are highlighted in the resource assessment report. The analysis provides a roadmap for expected production in each of the zones, assuming that the necessary hydraulic fracture is achieved. The following four scenarios are covered:

- Scenario 1 modeled a 61 m (200 ft.) propped fracture half-length;
- Scenario 2 modeled a 122 m (400 ft.) propped fracture half-length;
- Scenario 3 modeled a 183 m (600 ft.) propped fracture half-length;
- Scenario 4 modeled a 1,220 m (4,000 ft.) lateral completed with 20 fracture initiation points (64 m/210 ft. perforation cluster spacing), each with a created fracture with a 1,220 m (4000 ft.) propped half-length;

Scenario 3 (vertical) and Scenario 4 (horizontal) are illustrated in Figure 17 below.

![Scenario 3 and Scenario 4](image)

**Figure 17: Vertical and Lateral Drilling Scenarios Illustrated**

Based on these scenarios, the following drainage areas and number of wells are calculated:

- Scenario 1: 16.06 acres → 40 wells needed to deplete one section
- Scenario 2: 22.12 acres → 29 wells needed to deplete one section
- Scenario 3: 28.18 acres → 23 wells needed to deplete one section (vertical drilling)
- Scenario 4: 156.19 acres → 4 wells needed to deplete one section (horizontal drilling)

It is important to note that multiple completion designs can be simulated that will give variable drainage areas and cumulative production results. However, for this study, the best possible and feasible completion design has been selected. Scenario 4 (horizontal well) and Scenario 3 (vertical well) will be discussed below. These scenarios are separately illustrated in Figure 20 and 21.
Scenario 4: Horizontal Well

For Scenario 4, the analysis of each well is based on a drainage area of 156 acres, or one-fourth of the 640 acre section, for a 4,000 feet horizontal well. This translates to an optimal spacing of four lateral wells per section (i.e., 1 sq. mile) required for each developmental bench for effective development.

In order to successfully drain the entire 156 acres per well, the recommended completion strategy is to use a 20-stage hydraulic fracture in each zone. Each frack stage should be spaced at 210 ft. with a 400 ft. proppant fracture half-length, at half a pound per gallon concentration (20/40 white sand). To determine incremental production due to overlapping fracture geometries, dynamic simulation modeling is required that is beyond the scope of this study.

Establishing a development plan based on economic considerations requires local knowledge to determine the availability of drilling and completion equipment, infrastructure, environmental factors, commodity prices, and overall economic factors. Based on budgets set forth to execute the plan, the frequency and timing of the wells to be drilled can be formed.

Out of the 13 wells used for production simulation, Suleman-01 well is used as an example for further illustration of the development work plan. This plan can be applied and replicated in each of the identified areas and formation intervals.

The Suleman-01 section horizontal well development plan is as follows:

- Using the available data the estimated potential of Suleman-01 in Sembar is over 100 BCF/SEC of free GIP.
- Drilling target is a 1,220 m (4,000 ft.) horizontal well drilled in the Sembar pay zone of 55 m thickness at the depth of 3925-3980m.
- Completion design is a 20 stage hydraulic fracture stimulation spaced at 64 m (210 ft.) with a 1,220 m (4,000 ft.) propped fracture half-length. A multi-stage frac is illustrated in Figure 18 below.

![Figure 18: multiple frack stages in a horizontal well](image)

- Anticipated production performance initial production (IP) is 1,565 MCFE\(^{20}/D\) for the first 30 days, declining to 395 MCFE/D for a cumulative of 788 MMCFE in year 1, and yielding a recovery factor of 3.04% in year 10.

Figure 19 displays Scenario 4 as having the highest initial production. The rates also decline rapidly in the initial year (as is common for shale gas production). Furthermore, it shows the decline in production rate from 1,565 MCFE/D (at day 10) to 101 MCFE/D (during the 10\(^{th}\)

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\(^{20}\) MCFE: Thousand cubic feet equivalent, determined using the ratio of six Mcf. of natural gas to one bbl. of crude oil, condensate or natural gas liquids. MMCFE: million cubic feet equivalent.
year). This rapid decline indicates that more wells will need to be drilled to arrest rapid decline in production.

![Stage 1 Rate Predictions](image)

**Figure 19: Simulated production Decline Rate for Suleman 01**

**Table 12: Production Data for Scenario 4 – Horizontal Drilling (MMCFE$^{21}$)**

<table>
<thead>
<tr>
<th>10th Day Rate (MCFE/D)</th>
<th>30 Day Cum HC (MMCFE)</th>
<th>30th Day Rate (MCFE/D)</th>
<th>1Yr Cum HC (MMCFE)</th>
<th>1st Yr. Rate (MCFE/D)</th>
<th>5 Yr. Cum HC (MMCFE)</th>
<th>5th Yr. Rate (MCFE/D)</th>
<th>10 Yr. Cum HC (MMCFE)</th>
<th>10th Yr. Rate (MCFE/D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,565</td>
<td>57.9</td>
<td>1,023</td>
<td>243.4</td>
<td>395</td>
<td>569.5</td>
<td>150</td>
<td>788.3</td>
<td>101</td>
</tr>
</tbody>
</table>

Ultimately, the number of wells drilled annually defines the maximum production rates, and the total number of wells drilled over the entire field/area defines the plateau lifetime of the field. As mentioned above, four horizontal wells will be required to optimally drain a section (640 acres). Hence, the total production from four wells in 10 years is simulated to be 3,153.2 MMCFE.

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$^{21}$ Rate is MMCF/D while Cumulative is MMCFE
Scenario 3: Vertical Well with 183 m (600 ft.) propped fracture half-length

Another option that can be considered is to drill vertical wells instead of horizontal wells. This will increase the density of the wells in the section defined. The surface disruption will increase from 4 wells to 23 wells. An example can be seen in Figure 21 below.
The Suleman-01 vertical well development plan is as follows:

- Using the available data the estimated potential of Suleman-01 in Sembar is over 100 BCF/SEC of free GIP.

- Drilling target is a vertical well drilled in the Sembar pay zone of 55 m thickness at the depth of 3925-3980 m.

- Completion design is a 1 stage hydraulic fracture stimulation at 183 m (600 ft.) propped fracture half-length.

- Anticipated production performance initial production (IP) is 412 MCFE/D for the first 30 days, declining to 78 MCFE/D for a cumulative of 52 MMCFE in year 1, and yielding a recovery factor of 4.39% in year 10.

<table>
<thead>
<tr>
<th>10th Day Rate (MCFE/D)</th>
<th>30 Day Cum HC (MMCFE)</th>
<th>30th Day Rate (MCFE/D)</th>
<th>1Yr Cum HC (MMCFE)</th>
<th>1st Yr. Rate (MCFE/D)</th>
<th>5 Yr. Cum HC (MMCFE)</th>
<th>5th Yr. Rate (MCFE/D)</th>
<th>10 Yr. Cum HC (MMCFE)</th>
<th>10th Yr. Rate (MCFE/D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>412</td>
<td>13.7</td>
<td>229</td>
<td>52</td>
<td>79</td>
<td>132.7</td>
<td>150</td>
<td>205.2</td>
<td>36</td>
</tr>
</tbody>
</table>

Twenty-three wells will be required to optimally drain a 640 acres section with vertical wells. Hence, the total production from 23 wells in 10 years is simulated to be 4,720 MMCFE.
Vertical scenarios generate a higher recovery factor simply because of a higher number of wells being drilled. Economically speaking, if region consists of a thick concentrated pay zone, then the lateral scenario would be more feasible. However, in a region which consists of numerous smaller zones, where co-mingling is possible, then the vertical scenario may deem more beneficial.

This assessment is based on simulated wells results using software and cannot replicate actual well production information. The development work plan is considered as an example for one square mile section and one formation in the basin, and success is not guaranteed. With limited core data, triple combo data, sections that are largely washed out, and there is no prior production/completion information, there are a limited number of known variables in this study. For production optimization purposes, field parameters such as historic stimulation challenges, field hydrocarbon properties, reservoir extent, tubular data, current field completion practices, and field economic parameters factor in the completion analysis that could not be taken into consideration.

The basin scale model should be considered as a big picture model for evaluating overall basin property trends, estimating basin potential hydrocarbon volumes, and identifying favorable locations for further detailed analysis. Nevertheless, the large scale basin model for resource assessment, along with the 13 well locations, is used to develop this initial suggested work plan. Extrapolating these models to a field or basin level must be done with caution. The simulated production profiles for these 13 wells with single or multiple zones are attached in the Annexure for reference.

Using this proposed work plan, i.e., the simulated drilling, stimulation and production scenarios the costs are calculated in the following section. These cost estimates are taken from Pakistan and are applied on the work plan to find the production cost estimates with available data.

The shale completion and production information obtained at the wellsite is not available at this stage in Pakistan. An iterative process is an ideal way in order to draw a consensus among the predictions/simulations of the reservoir model and the production observations recorded along with the results of the fracturing model and the observations recorded by the actual stimulation treatment. Thereafter the best work plan can be devised at a stage when shale gas production data and microseismic data are available to optimize the well spacing.
7. CAPITAL INVESTMENT PROFILE

A financial model is developed to calculate the wellhead cost per section\(^{22}\) in Middle and Lower Indus Basins in Pakistan. This can also be termed as the wellhead cost per unit (MMBTU) for a section. This cost is an indicative number and may reduce once multiple sections are drilled and developed in a particular concession.

The financial model developed is independent of factors outside the core projects (shale gas) and does not take into account any additional economic benefits that may flow to the overall economy due to shale gas development.

As the shale gas development requires new technologies in addition to conventional drilling techniques, such as hydraulic fracturing, at initial stages these technologies would have a higher cost. As witnessed globally, the cost will be reduced once shale plays are well understood and required technology is in place. At the same time the positive impact of economies of scale must be kept in view for longer-term projects. In the U.S. not only the costs were optimized but the development time was also reduced due to enhanced efficiencies. Data available from various developments in U.S. saw a cost reduction of up to 30% even in a single year\(^{23}\).

In shale economics the production of liquids from a shale gas/oil field does influence the overall economics of extraction, as long as the price of oil is higher. However, for the purpose of analysis we have not taken shale oil and the financial model presented is dependent only on shale gas numbers. The following assumptions are made to simplify the financial model:

Input assumptions

- The financial model developed is for one section covering an area of 640 acres or 1 square mile.
- The model dealt with input data of 13 sections. Each section was developed with 4 horizontal wells (1,220 m or 4,000 feet lateral) each based on a drainage area of 156 acres, or \(1/4\) of the 640 acre section.
- The analysis is done by taking into account Sembar and Lower Goru formations. Production from Ghazij and Ranikot formations being uneconomical is not included in the analysis.
- For different sections, there are multiple zones within the same formation.
- Each zone requires about 20 frack stages.
- For the purpose of capital expenditures (CAPEX), drilling costs, below ground installations, well completion, stimulation (hydraulic fracturing) and wellhead costs are taken.
- In Pakistan, the concession areas are already held by various E&P companies with conventional oil/gas operations, and therefore it is assumed that costs other than well CAPEX costs (if any) will be absorbed by ongoing operations within the concession.
- It is assumed that adequate pipelines and gas processing facilities infrastructure are already available\(^{24}\) at least for the initial stage. It is the responsibility of the Government to provide

\[\text{One section is 640 acres.}\]
\[\text{Chesapeake Energy’s costs reduced to 30% in a single year working in Haynesville.}\]
\[\text{In Australia first 2 wells for shale gas were drilled in 2011. These vertical test wells were drilled closer to pipeline and gas processing facilities (350m from existing pipeline and 8 KM from processing plants), which}\]
infrastructure; however, following the Australian example it will perhaps be feasible to plan initial wells in areas with already available infrastructure.

- An operating cost of $0.22 per MMBTU ($1.5/BOE) has been taken for the model, which covers the per unit OPEX, Processing cost as well as environment risk mitigation costs such as safeguards for water pollution, water overuse, disposal of waste, and adherence to any new enhanced environmental legislations.

- G&A of $50,000 per year is assumed for direct linkage with shale gas operations per section.

- Cost for hydraulic fracturing job is taken from services companies operating in Pakistan. Per frack job at present, costs around $500,000.

- Proppants\(^{25}\) and water cost is part of frack cost, which is borne by the service companies. Water cost is approximately 1% of the fracturing whereas cost of proppants is 20-25% of the total frack job cost.

- Where desalinated water cost is used an additional cost of $0.1 per gallon is taken. This is based on the scenario that seawater will be used for hydraulic fracturing. The seawater will be treated at a Reverse Osmosis (RO)/desalination plant located at the sea in Karachi, and desalinated water will then be transported to Middle Indus Basin through bowsers. For the cost of transportation an up/down distance of 1,200 km is assumed. For further details, refer to the Desalinated Water section of this document.

- A typical well of 4,000 m can be completed within a period of 3-4 months including drilling and frack jobs, and therefore the assumption is that production starts in the same year.

- Production data is for a period of 10 years based on production analysis.

- For base case fiscal terms as per Petroleum Policy 2012 (Implemented through 5th Schedule of Income Ordinance 2001) is taken.

- The Corporate Tax rate in this case is 40%.

- Royalty is 12.5% of wellhead value\(^{26}\), which is also a tax-deductible expense.

- For the purpose of Royalty transportation charges are deducted as per Rule 39 of Pakistan Onshore Petroleum (Exploration & Production) Rules, 2013.

- As the analysis is based on per section some costs are not taken such as: windfall levy\(^{27}\) WPPF and WWF\(^{28}\).

- Furthermore decommissioning cost\(^{29}\) is also not accounted for in the model.

- Base Operator Take is assumed to be 20%.

\(^{25}\) A proppant is a solid material, typically sand, treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment.

\(^{26}\) The wellhead value means the value of Petroleum as defined in clause 39 of Pakistan Onshore Petroleum (Exploration & Production Rules 2013), which essentially is the price of petroleum, less allowable transportation cost.

\(^{27}\) WPPF (Workers Profit Participation Fund) & WWF (Workers Welfare Fund) are not taken for the purpose of the model as the assumption is that it is at the company level and not at section level.

\(^{29}\) Cost associated with a process or product which need to be factored in when evaluating overall life time costs
Furthermore, as per discussions with various Service Companies\(^\text{30}\), it was confirmed that they can provide discounts up to 50% for large scale shale operations due to economies of scale and low carrying cost of their equipment. Based on this feedback from companies, for Pilot Case cost optimization of 30% has been assumed for the following items: drilling rig costs, testing services, wire-line services, perforation service and stimulation.

- Gas heating value is assumed to be 1,000 BTU per 1 CFT.

**WELL COST**

It must be highlighted that shale gas operations differ considerably from conventional gas operations and there is a large degree of uncertainty of the operating parameters. Moreover, unlike conventional formations shale requires multiple wells to achieve similar production results. To find out how much a shale gas well will cost, multiple interviews were conducted with E&P and service companies. A financial questionnaire was also shared, which was filled out and returned, that helped in gathering data with regards to various capital and operating costs. It was important not to take deterministic values as cost of a well is never a definite number. For this reason, Monte Carlo Simulation\(^\text{31}\) was performed with the data collected from oil and gas sector. The probability analysis was completed against a new horizontal well and the costs associated with it were acquired. As industry standard, P55 (i.e. 55%) chances of encountering such a cost for a horizontal well was taken.

For each section, four wells are drilled. Each well is first drilled to a vertical extent, after which it is drilled laterally and then fractured hydraulically.

Table 14 below shows the cost of drilling and carrying out stimulation of each well. In case E&P operators use abandoned wells and/or wells requiring work over in their concession areas their well development costs will further reduce. It is however important to note that re-entry in any old well would require significant testing to ensure that such old well will be able to handle high pressures that will be applied during fracturing techniques.

The cost figures mostly are probabilities (55%) based on answers received from companies and thus are subject to change. It can also be seen that hydraulic fracturing has a momentous effect on the cost of shale well. Thus, any changes in these charges can have an overall cost effect.

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\(^{30}\) Schlumberger, Weatherford, etc.

\(^{31}\) A computerized mathematical technique that allows people to account for risk in quantitative analysis and decision making.
Table 14: Cost Breakdown for Vertical Drilling, Lateral Section Drilling and Hydraulic Fracturing for a Single Stage Well

Estimated well cost for Haynesville U.S. is about $9.5 to 10.5 million (Comstock Resources).

WELL SCENARIOS

The financial model developed caters for CAPEX optimization in three scenarios described in the following section. Please note that these well drill duration scenarios are to analyse the drilling frequency and its financial impact and are different from the four-well completion scenarios discussed in the Work Plan.

- Scenario 1 (S1) → all four wells are drilled in first year
- Scenario 2 (S2) → two wells are drilled in the first year and additional two wells are drilled the next year
- Scenario 3 (S3) → each well is drilled in subsequent year (in four year time span)

The modeling results infer that the financial impact of these drill duration/frequency scenarios is insignificant.

Table 15: Breakeven Cost for Each Drilling Scenario
Figure 22: Breakeven Cost for 13 Sections US $/MMBTU (Horizontal Development)

It can be seen that wells located in low hydrocarbon regions give unreasonable values for wellhead cost, and exploration is not economically feasible. Almost 8 sections were found to be uneconomical (as shown in Figure 22 above) and therefore were dropped as part of the optimization. Further analysis was conducted on 5 sections including: Pir Patho-01, Raj-01, Babar-01, Suleman-01 and Jumman Shah-01.

All the wells were dropped in Ranikot and Ghazij as these were not thermally mature and added uncertainty in the wellhead costs.

Furthermore, wells and/or zones that had cumulative production of equal or greater than 1 BCF after 10 years were considered and all others were dropped.

As an outcome remaining zones were used (i.e., 1 zone out of 7 for Pir Patho 01, 2 zones out of 6 for Raj 01, and 2 zones out of 3 for Jumman Shah 01).

Suleman 01 was the only exception to this case (0.788 BCF 10 year cumulative production) so that there was more than one well representation in the Sembar formation. Almost all the dropped wells were located in low potential areas thus are least likely to be developed in the near future. Figure 23 illustrates the geographic representation of the wells that were selected for the economic modeling.
Furthermore, the analysis is done with S2 (i.e., two wells drilled in the first year and two additional wells drilled the year after). This also keeps production stable for at least two subsequent years. For this study, the Net Present Value (NPV)\[32\] is kept at zero to arrive at the breakeven cost at $/MMBTU (Figure 24).

---

\[32\] The difference between the present value of cash inflows and the present value of cash outflows. NPV is used in capital budgeting to analyze the profitability of an investment or project.
Figure 24: Wellhead Cost per Unit for each 5 sections (Base Case Cost Scenario)

Shale gas economics at initial project development stages, if compared to project economics in midterm and long term, varies quite significantly.

Based on the current dynamics, a cost should be considered for the pilot case that is the breakeven cost for E&P companies when they undertake shale gas exploitation. The Government can consider taking this cost as the benchmark. After the initial phase the policy incentives can be reviewed for mid-term and long term. The following analysis shows potential benefits in all three scenarios: Short-Term Case (first 5 years), Mid-Term Case (subsequent 5 years), and Long-Term Case (after 10 years).

**Short-Term Case: First 5 years**

This is the base case with five sections gives a volumetric cost per unit of US $ 11.21/MMBTU.

<table>
<thead>
<tr>
<th>Table 16: Wellhead Cost per Unit (Pilot Case)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead Cost Per Unit (US $/MMBTU)</td>
</tr>
<tr>
<td>Base Case Breakeven Cost</td>
</tr>
<tr>
<td><strong>Parameters</strong></td>
</tr>
<tr>
<td>Case 1</td>
</tr>
<tr>
<td>Case 2</td>
</tr>
<tr>
<td>Case 3</td>
</tr>
<tr>
<td>Case 4</td>
</tr>
<tr>
<td>High</td>
</tr>
<tr>
<td>Low</td>
</tr>
</tbody>
</table>

Furthermore, different sensitivities are run to estimate the effect of certain factors such as enhancing the operator take, the impact of taxation and royalty, and the discount on CAPEX as shown in and Figure 25.
Figure 25: Wellhead Cost per Unit for Different Cases (Short-Term Scenario)

Case 1: Operator take increased to 25%, results in a breakeven cost of $11.91/MMBTU which is an increase from base case by $0.70 per MMBTU;

Case 2: Operator take reduced to 15%, results in a breakeven cost of $10.43/MMBTU with a decrease from base case by $0.78 per MMBTU;

Case 3: A tax and royalty holiday for a period of 10 years is assumed (for comparison to LNG import which are not subject to such levies), this results in a breakeven cost of $9.07/MMBTU with a decrease from base case by 2.14 per MMBTU;

Case 4: It is assumed that required quantities of freshwater is not available in the area of development, and as result seawater source is used after factoring in cost of desalination and transportation to development site. Incorporating such costs the breakeven unit cost comes to $11.64/MMBTU, which is an increase from, base case by $0.43/MMBTU.

Mid-Term Case: 5-10 Years

It will be a safe assumption that with time shale gas development will become more economical due to scalability as well as improvement, and enhanced accessibility of technology. We have seen the same trend in U.S. and as per discussions, the service companies seem very confident to see the costs coming down. It is assumed that the initial reduction in cost could be after five years of initial development (up to 40% of the originally stated). With this optimization the volumetric cost for the same five sections would come down to US $9.94/MMBTU.

Table 17: Wellhead Cost per unit (Mid-Term Case)

<table>
<thead>
<tr>
<th>Wellhead Cost Per Unit (US $/MMBTU)</th>
<th>Mid -Term Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case Breakeven Cost</td>
<td>9.94</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Break Even Cost</th>
<th>Variance from Base Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1: Operator Take 25%</td>
<td>10.55</td>
<td>0.61</td>
</tr>
<tr>
<td>Case 2: Operator Take 15%</td>
<td>9.25</td>
<td>-0.69</td>
</tr>
<tr>
<td>Case 3: No Tax + No Royalty</td>
<td>8.05</td>
<td>-1.89</td>
</tr>
<tr>
<td>Case 4: Using 100 % Desalinated &amp;/or Produced Water</td>
<td>10.3</td>
<td>0.36</td>
</tr>
<tr>
<td>High</td>
<td>10.55</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>8.05</td>
<td></td>
</tr>
</tbody>
</table>
Furthermore, it’s encouraging to see that even with usage of 100% desalinated water the cost will be $10.33/MMBTU, which seems reasonable.

**Long-Term Case: After 10 Years**

Once shale gas development picks up pace in Pakistan, global technology companies will find it feasible to enter Pakistan and may offer services on very competitive rates. This may bring a cost optimization of up to 50%. If this is assumed to be a long-term scenario then the volumetric average for the five sections under consideration would be $8.67/MMBTU.

**Table 18: Wellhead Cost per unit (Long-Term Case)**

<table>
<thead>
<tr>
<th>Wellhead Cost Per Unit (US $/MMBTU)</th>
<th>Long-Term Case 8.67</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Parameters</strong></td>
<td><strong>Break Even Cost</strong></td>
</tr>
<tr>
<td>Case 1 Operator Take 25%</td>
<td>9.19</td>
</tr>
<tr>
<td>Case 2 Operator Take 15%</td>
<td>8.08</td>
</tr>
<tr>
<td>Case 3 No Tax + No Royalty</td>
<td>7.02</td>
</tr>
<tr>
<td>Case 4 Using 100% Desalinated &amp;/or Produced Water</td>
<td>8.97</td>
</tr>
<tr>
<td><strong>High</strong></td>
<td>9.19</td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td>7.02</td>
</tr>
</tbody>
</table>

With the resource in place, shale gas development is largely dependent on the technology development and any breakthrough in the development of resources that came about was due to continuous improvement and innovation. Even with a dip in global oil prices, companies continue to invest in technology to improve efficiency and bring down the cost. One area of technology improvement is the use of desalinated water at lower costs. If this breakthrough comes about at large scale then costs may reduce substantially. However, even if saline water is at a constant cost, the wellhead cost remains below $10/MMBTU.

From the above scenarios and sensitivities it can be noted that CAPEX plays a pivotal role in determining the breakeven cost. It is important to note that the work plan can be modified and will vary across different regions. Moreover, any natural gas liquids (NGLs) that are extracted along with gas can be a bonanza. This should give shale gas a competitive edge as compared to imported gas, LNG (case 3), and furnace oil. Through technological sophistication and application, the CAPEX for drilling shale well will drop over time (as seen in the US). Moreover, by using alternative to freshwater the wellhead cost increases by a small factor, Pakistan being a water stressed country with huge energy supply-demand gap, this cost increase is nominal. Again, technological sophistication can bring this cost down as well with time.

**Table 19: Summary for Wellhead Cost per unit (Short-Term, Mid-Term and Long-Term)**

<table>
<thead>
<tr>
<th>Wellhead Cost Per Unit (US $/MMBTU)</th>
<th>Short-Term Case</th>
<th>Mid-Term Case</th>
<th>Long-Term Case</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case Breakeven Cost</strong></td>
<td>11.21</td>
<td>9.94</td>
<td>8.67</td>
</tr>
<tr>
<td><strong>Parameters</strong></td>
<td><strong>Break Even Cost</strong></td>
<td><strong>Break Even Cost</strong></td>
<td><strong>Break Even Cost</strong></td>
</tr>
<tr>
<td>Case 1 Operator Take 25%</td>
<td>11.91</td>
<td>10.55</td>
<td>9.19</td>
</tr>
<tr>
<td>Case 2 Operator Take 15%</td>
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<td>9.07</td>
<td>8.05</td>
<td>7.02</td>
</tr>
<tr>
<td>Case 4 Using 100% Desalinated &amp;/or Produced Water</td>
<td>11.64</td>
<td>10.3</td>
<td>8.97</td>
</tr>
<tr>
<td><strong>High</strong></td>
<td>11.91</td>
<td>10.55</td>
<td>9.19</td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td>9.07</td>
<td>8.05</td>
<td>7.02</td>
</tr>
</tbody>
</table>
It is clearly evident that cost of shale gas development will reduce over time as shown in Table 19 above. These cost reductions have been witnessed in other parts of the world due to efficiencies and introduction of better technologies.

Whereas the above financial analysis only looks at the standalone project economics, when the Government decides to announce a policy incentive for shale gas exploitation it must take into account the additional development and economic impact that shale gas projects will begin in Pakistan.

**Vertical Drilling Scenario**

An economic model for the same five sections (Sembar and Lower Goru Formation) was prepared to look at viability of vertical development plan. As per the data, a total of 23 wells are required to be drilled to drain each section and achieve a desired level of production. Detailed discussion on the vertical completion scenario is available in the development work plan section of this document. Furthermore, each vertical well would require only lesser frack jobs per well compared to horizontal.

The volumetric cost for the vertical scenario is $18.29/MMBTU.

From the analyses it appears that vertical well scenario is not feasible as compared to horizontal development. More wells need to be drilled in the same section area with very low production.

Furthermore, vertical well development will also have many technical challenges due to high density of wells per section. The vertical well drilling may also pose environment challenges due to increased amount of surface disruption in a limited area of 640 acres.

**Additional Considerations**

The above financial model only covers the economics per section of shale gas and does not take any upside for the overall economy.

Shale gas development will certainly have short-term stimulus and long-term economic effects on the national growth.

Some upsides to be considered are:

- Industrial competitiveness (long term), which is completely dependent on availability of gas as fuel or feedstock.
- Employment generation impacts, etc., leading to overall economic value addition
- Carbon credits from possible savings due to using a cleaner fuel (gas) as part of overall energy evaluation.
- Energy Security through access to local energy resources at an overall affordable price and a longer production duration.
8. EXISTING LEGAL, REGULATORY AND FISCAL FRAMEWORK

Under the Constitution of Pakistan, mineral oil and natural gas, which are liquids and substances declared by Federal law to be dangerously inflammable, are Federal subjects. All these are mentioned in Clause 2 of Part II of the Fourth Schedule of the Constitution. The basic law that regulates the upstream sector is the Regulation of Mines and Oil Fields and Mineral Development (Government Control) Act, 1948.

The current legal framework for the upstream sector is as follows:

- Regulation of Mines and Oilfields and Mineral Development (Government Control) Act, 1948, including Amendment of 1976
- Territorial Waters and Maritime Zones Act, 1976
- Income Tax Ordinance, 2001 (fifth schedule)
- Mines Act, 1923
- Pakistan Environmental Protection Act 1997 (Federal; Post 18th amendment provincial)
- The National Environmental Quality Standards (Self-Monitoring and Reporting by Industry) Rules 2001
- Oil and Gas (Safety in Drilling and Development) Regulations, 1974
- The Land Acquisition Act 1894
- Pakistan Petroleum (Exploration and Production) Rules, 1986
- Pakistan Petroleum (Exploration and Production) Rules, 2001
- Pakistan Offshore Petroleum (Exploration and Production) Rules, 2003
- Pakistan Onshore Petroleum (Exploration and Production) Rules, 2009
- Pakistan Onshore Petroleum (Exploration and Production) Rules, 2013
- Petroleum Exploration & Production Policy 1994
- Petroleum Exploration & Production Policy 2001
- Petroleum Exploration & Production Policy 2007
- Petroleum Exploration & Production Policy 2009
- Petroleum Exploration & Production Policy 2012
- Tight Gas Policy, 2011
- Low BTU Gas Policy, 2012

The 1956 Constitution did not last for long, and was replaced by another one in 1962. Eventually, it was replaced by the 1973 Constitution, which remains in force. Under Clause 2 of Part II of the Fourth Schedule and Article 97 of the Constitution, the Federal Government has exclusive jurisdiction to legislate and regulate matters pertaining to mineral oil and natural
gas, which are liquids and substances declared by Federal law to be dangerously inflammable. However, under the Constitution’s Article 154(1), the Council of Common Interest, which consists of all Provincial Chief Ministers and is headed by the Prime Minister, is obliged to formulate and regulate policies in relation to matters in Part II of Federal Legislative List and is to exercise supervision and control over related institutions.

Similarly, by virtue of article 172(2) of the 1973 Constitution “all lands, mineral and other things of value within the continental shelf or underlying the ocean within the territorial waters of Pakistan shall vest in the Federal Government”.

18th Amendment in the Constitution

The Eighteenth Amendment passed in April 2010, inserted clause (3) to article 172. This clause states that:

“Subject to the existing commitments and obligations, mineral oil and natural gas within the Province or the territorial waters adjacent thereto shall vest jointly and equally in that Province and the Federal Government.”

The above insertion implies that post Eighteenth Amendment, mineral oil and natural gas located within a province will vest jointly and equally between that particular province and the Federal Government. However, in view of Clause 2 of Part II of the Fourth Schedule of the Constitution, the legislation shall remain with the Federal Government subject to the provisions of the Constitution dealing with the Council of Common Interests. By virtue of Article 97, the Federal Government shall have the right to regulate all matters where the Parliament has the exclusive right to legislate.

The Federal jurisdiction over oil and gas has always remained with the Federal Government under the various constitutions. Accordingly, the Regulation of Mines and Oil Field and Mineral Development (Government Control) Act 1948 continues to govern petroleum exploration and production in Pakistan. The power to make rules is vested in the appropriate government as defined under section 2 of the 1948 Act. Section 6 of the 1948 Act defines the appropriate government as the Central government when dealing with mines of nuclear substances, oil fields, gas fields and the development of nuclear substances, mineral oil and gas; and the provincial government when dealing with other mines and mineral development.

The 1948 Act maps out the areas where the Federal Government is to make rules. This includes matters relating to application for and grant of licenses and leases, determination of the rate and condition of royalties, rents and taxes, rules regarding ores and oil refining, production, distribution, storage, and price fixing. The Government is also empowered to impose penalties in the case of non-compliance with a rule.

In 1976, the Act was modified and amended by the Regulation of Mines and Oil Fields and Mineral Development (Government Control) Amendment Act 1976, to give the Government the option of entering into a production sharing agreement with exploration companies upon negotiated terms.

The 1976 Amendment also added Section 3B, which gave the government of Pakistan the authority to give any company, whether incorporated in Pakistan or outside Pakistan, a license and a lease to explore, prospect, and mine petroleum. Such a company could be entitled to the concessions specified in the Schedule in addition to any concessions for the time being admissible to it under any other law or the rules made under the 1948 Act.
PETROLEUM CONCESSION AGREEMENT

Based on the 2013 Rules, the Government of Pakistan has prepared the Model Petroleum Concession Agreement (PCA), which forms the basis for signing a PCA. The Model PCA deals with the rights and liabilities of the Working Interest Owners, which include but are not limited to: ownership percentages of the Parties to the PCA; Exploration Work Program; Relinquishment; Discovery and Development of Petroleum; Wellhead Value of the Petroleum; Right of Acquisition of Petroleum, and its disposal; Imports and Exports; and Taxation; Management and Operations; furnishing of Reports and Information; Contribution to Joint Operations; Development Financing; Setting-up of Pipelines, Refinery, LPG and Natural Gas Processing Plants; discovery of Other Minerals while exploring for Petroleum; Audit; payment of Production Bonuses and Social Welfare; and Training Obligations.

As there is no shale gas framework at present, the model PCA is silent on the question of shale gas. With regard to the issue as to whether the model PCA needs to be revised to deal with shale gas, the same may be based on the new Shale Gas Policy Framework Guidance Document.

The term “Area” as defined in the PCA relates to surface and not sub-surface. For new concessions, the Government may consider restricting the Area as per exploited resource. Presently, there is no restriction on the depth of the Area covered by the PCA, or on fracking. A new framework needs to be developed for shale gas exploration so as to protect the right of existing E&P license and Development & Production Lease (D&PL) holders.

The present PCA links the definition of Petroleum to the Pakistan Onshore Petroleum (Exploration & Production) Rules 2013, which is defined to mean “all liquid and gaseous hydrocarbons existing in their natural condition in the strata, as well as all substances, including sulphur, produced in association with such hydrocarbons, but does not include basic sediments and water.”

FISCAL FRAMEWORK

There is currently no fiscal framework for shale gas projects; however, the Petroleum Exploration & Production Policy 2012 (Policy 2012) defines the fiscal framework for conventional oil and gas projects. In addition to Policy 2012, other policies are as follows:

- Tight Gas Policy, 2011;
- Low BTU Gas Policy, 2012; and

The Income Tax Ordinance 2001 (2001 Ordinance), as amended from time to time, is the governing income tax legislation. Part I of the Fifth Schedule to the Ordinance deals with the computation of profits and gains or income from petroleum E&P activities in Pakistan. The Fifth Schedule provides that all expenses incurred after commencement of commercial production that are not capital or personal in nature are deductible, provided they are incurred “wholly and exclusively” for the purpose of petroleum E&P activities. However, certain expenses, such as Royalty payments and depreciation are deducted on the basis of specific provisions of the 2001 Ordinance. The rate of Royalty is 12.5% and the Corporate Income Tax is 40% of the amount of profits or gains from all new PCAs and PSAs. Table 20 below compares the taxation regimes between 2009 and 2012 policies.
The following Table 21 defines the federal excise duty based on the description of hydrocarbons sold.
As per the international practice of providing incentives to shale operations the Government of Pakistan (GOP) can provide incentives to boost shale gas development operations in Pakistan. From the analysis in section “Capital Investment Profile”, it is assessed that the fiscal incentives provided by GOP to E&P players for shale gas project development can include:

- Providing a mechanism that yields suitable returns to investors comparable internationally;
- Offering a royalty holiday, as is the case with Offshore concessions; and
- Providing a cut in Corporate Income Tax or Royalty.

An additional incentive may include loans for shale gas projects at attractive financing rates. The State Bank of Pakistan can develop a scheme to finance shale gas projects, whereby it can compensate banks for the reduction in interest rates. This would encourage local companies and may not be a lucrative offering for foreign companies who (in any case) get cheaper financing from international markets. As per discussions with foreign E&P companies, it appears that foreign companies have access to cheaper financing from international markets and, therefore, do not opt to borrow locally in Pakistan.

In the wake of dwindling oil prices, financial institutions will be apprehensive to lend for shale gas projects without government support. As per Standard & Poor’s New York May 2015 report, the credit rating for almost half of the 105 U.S. E&P companies has been downgraded due to missing interest payments because of a shortage in expected revenues.

Other countries have devised specific incentives in order to attract investment in shale gas development. In October 2013, China (through its National Energy Administration) issued a Shale Gas Industry Policy and provided the following incentives:

- Market oriented pricing mechanism.

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Table 21: Federal Excise Duty

<table>
<thead>
<tr>
<th>Reference no.</th>
<th>Description of Goods</th>
<th>Heading or subheading number</th>
<th>Rate of duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>Liquefied natural gas</td>
<td>2711.11</td>
<td>PKR 17.18 per 100 cubic meters</td>
</tr>
<tr>
<td>32</td>
<td>Liquefied propane</td>
<td>2711.11</td>
<td>PKR 17.18 per 100 cubic meters</td>
</tr>
<tr>
<td>33</td>
<td>Liquefied butanes</td>
<td>2711.13</td>
<td>PKR 17.18 per 100 cubic meters</td>
</tr>
<tr>
<td>34</td>
<td>Liquefied ethylene, propylene, butylene and butadiene</td>
<td>2711.14</td>
<td>PKR 17.18 per 100 cubic meters</td>
</tr>
<tr>
<td>35</td>
<td>Other liquefied petroleum gases and gaseous hydrocarbons</td>
<td>2711.19</td>
<td>PKR 17.18 per 100 cubic meters</td>
</tr>
<tr>
<td>36</td>
<td>Natural gas in gaseous state</td>
<td>2711.21</td>
<td>PKR 10 per million BTU (mmbtu)</td>
</tr>
<tr>
<td>37</td>
<td>Other petroleum gases in gaseous state</td>
<td>2711.29</td>
<td>PKR 10 per MMBTu</td>
</tr>
</tbody>
</table>

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• Encouraging Chinese companies to engage with foreign technologically capable companies in the field of shale gas in order to introduce technologies as well as production and management expertise.

• Reduction/exemption in mineral resource compensation fees and/or mineral right usage fees for shale gas exploitation enterprises.

• The state will also develop and issue regulations on tax incentive policies relating to resource tax, value added tax, and income tax.

• Exemption from duties on equipment for shale gas development, subject to conditions met.

Countries such as Argentina that do not have specific shale gas regulations have opted for developing shale gas projects under the current regulatory and fiscal regime for conventional oil and gas resources.

Any new fiscal terms for shale gas development in Pakistan will have to be devised keeping in view the following:

• Existing framework for conventional resources;

• Fiscal space available to the Government for providing incentives, including subsidies, tax holidays, etc.; and

• Restrictions for providing subsidies (Pakistan is part of an IMF program that requires a reduction in subsidies).

Detailed discussion and assessment on environmental and regulatory guidelines will be covered in the subsequent Milestone.
9. CONCLUSION

Despite the rise of shale development in the USA and the fact that it has established a basis on which to estimate how the shale gas and oil industry might develop in Pakistan, the possible predictive scenarios for Pakistan’s shale industry will still depend on many factors. Some of these factors remain indeterminate till an appraisal well is drilled and tested for the confirmation of resource.

The aim of the capital investment profile has been to predict an indicative required wellhead cost based on the resource number and simulated well behavior in the Middle and Lower Indus Basin. It is clearly evident that the required wellhead cost could be correlated with capital intensity\(^1\) and reservoir EUR, which are major parameters in shale gas development (i.e., shale projects are more capital intensive as opposed to conventional oil and gas projects). The same parameter (i.e., capital intensity) is also very sensitive as even a small variation can alter the project economics to a great extent.

It is clear from the analysis undertaken, as well as discussions with various E&P and service companies, that important parameters that control the required wellhead cost are:

- The behavior of Pakistan’s shale formations - very limited data is currently available as to the kind of capital effort that is actually required on ground. The real production behaviors and corresponding capital effort will only be known after actual wells (for the purpose of shale gas) are drilled.

- The capital costs of well drilling and cost of stimulation.

- The initial production rate of wells in the field.

- The fiscal regime, including royalties, taxes, and investment incentives. For the purpose of the model, a fiscal regime applicable to conventional fields is assumed as per Petroleum Policy 2012.

Although available information is limited, the model is sufficiently developed to analyze the required wellhead cost for shale gas wells, provided more detailed data is available.

It is reasonable to assume that the future actions might take the form of a two-staged process. The first stage will continue to prove the existence of the resource and how easily it can be recovered. From the industry’s perspective, there is one simple consideration for any progressive development plan, namely to determine if the proposition is commercially viable for investors, especially when working under any constraints. If the commercial viability is called into doubt then future development is likely to be very slow or curtailed.

A second stage might then be a pilot or early development program that is based on sighting well pads in locations that are most easily approved by the Directorate General Petroleum Concessions (DGPC), but which also cover the most prospective resource areas. The steps necessary to implement the pilot program would be accentuated in the Shale Gas Policy Framework Guidance Document.

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\(^1\) Capital intensity is the amount of fixed or real capital present in relation to other factors of production, especially labor. At the level of either a production process or the aggregate economy, it may be estimated by the capital to labor ratio, such as from the points along a capital/labor isoquant.
RECOMMENDATIONS

There are a number of positive steps that could be taken by the Government to ensure that operators are able to exploit the shale potential of Pakistan while maintaining the use of best practices, and that areas that are environmentally sensitive are not exposed to unnecessary risks. All recommendations will be covered in-depth in the subsequent Milestone report and the final report of the study.

It is Pakistan’s aim to maximize the potential of the country’s resources and stimulate investment. In this respect, the Government of Pakistan needs to facilitate the exploration of Pakistan’s shale resources to ascertain its future potential, as shale gas could play an important role in ensuring a reliable, secure, and affordable supply of energy to power homes and industries.

Favorable Tax Regime

A favorable tax regime is an important part of this process to attract the right levels of investment. The energy industry needs to undertake the right levels of exploration to ensure commercial viability. Setting the right tax framework in place is at the heart of this process as the same will directly impact the operators return. The taxation of profits from oil and gas exploration is governed by the provisions of Part I of the Fifth Schedule of the Income Tax Ordinance 2001.

Under the provisions of the Model PCA (article 14.2), read with clause 3 of the Schedule to the 1948 Act, expenditure incurred on exploration prior to commercial production can be offset against profits of even other activities and ventures undertaken by the same entity or company.

Under rule 2(3) of Part I of the Fifth Schedule to the Income Tax Ordinance, the prior commercial production expenditure can be carried forward for offsetting purposes for up to either six years or ten years. The effect of such enhancement is to maintain the time value of expenditure and losses, and to reduce both and to defer tax on future profits.

In order to provide an incentive to shale gas projects, and boost attractiveness, the Government can either decrease the percentages, or increase the years for carrying forward the losses in the case of shale gas projects.

Royalty Rate

As shale gas projects are more capital intensive compared to those of conventional oil and gas projects, the Government may consider providing relief to companies by either reducing the rate of royalty or providing a scale such as that provided for offshore hydrocarbon development (see section “Steps for Implementations of Technology in Pakistan” below).

<table>
<thead>
<tr>
<th>Table 22: Offshore Royalty in Pakistan</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Off Shore Royalty</strong></td>
</tr>
<tr>
<td>First 48 Calendar Months after Commencement of Commercial Production</td>
</tr>
<tr>
<td>Months 49 to 60 inclusive</td>
</tr>
<tr>
<td>Calendar Months 61 to 72 inclusive</td>
</tr>
<tr>
<td>Calendar Months 73 and greater</td>
</tr>
</tbody>
</table>
Steps for Implementations of Technology in Pakistan

It is worthwhile to note that the E&P industry in Pakistan is adapting the latest oil and gas exploration/exploitation technology available globally. The increased volume of work in this domain will help to receive discounted rates from service companies. These discounts will reduce costs and make shale gas projects economically viable. At the same time, a motivational factor for the operators in their long term commitments would be a reasonable return on investment and favorable legal and fiscal regime.

Some of the recommendations addressing the technology issues are:

- Government of Pakistan to come up with a broad framework for shale gas. This report and the Shale Gas Policy Guideline Document that is covered in the subsequent Milestone may also be consulted for this purpose.

- E&P companies (with help from GOP/DGPC) can form consortiums and joint ventures to improve project feasibilities, which may enable them to get better prices from service providers ultimately leading to a reasonable well-head cost. The large volume or combined work plan of various companies will provide a good platform to negotiate prices with service companies as the mobilization and demobilization cost will be spread over large volumes.

- A consortium of state-owned and multinational companies could undertake a Pilot Project, with an active sharing of information with DGPC. Shale gas project costs vary after drilling the first few wells. This impact would need to be translated into the policy framework and, therefore, it is essential for DGPC to fully comprehend the behavior of costs after a few initial wells are drilled. DGPC could agree on a pilot project with a group of state owned and/or private companies in existing concessions.

- One additional step would be to establish/refurbish oil and gas laboratories in Pakistan with capability to undertake both conventional and specialized analyses. At present, cores and cuttings are sent abroad for analyses due to limited availability of these facilities in Pakistan. The same will reduce cost as well as time required to export the core, ditch-cutting data, and receive the results.

- Revisit the regulations and legislation concerning health, safety and environment; water (i.e., surface and ground water); air; induced seismicity (i.e., earthquakes); and waste management to determine how they will impact exploitation and production of shale gas/oil.

- Governments and companies, through collective action, can develop source water protection and management plans. Governments and businesses in the early stages of developing shale resources have a unique opportunity to work collectively with key river basin stakeholders to develop source water protection and management plans that help reduce business risks; promote a shared water sourcing and recycling infrastructure; and improve the sustainable management of watersheds and aquifers.

- Produced water is either being evaporated via ponds or disposed with injection wells. Drilling a disposal well is relatively more expensive than recycling. Furthermore, disposal wells have a causal link with seismic activities and use of it should be discouraged. Also, evaporation ponds if not properly lined can lead to seepage, which is an environmental risk. The E&P sector should phase out evaporation ponds and disposal wells with alternate ways. Companies can evaluate their potential for using non-freshwater sources and build a business case for investing in technology to recycle or reuse water, use brackish water, or otherwise significantly reduce freshwater withdrawals. Regulations can be framed around this area to encourage water reuse practice within the domain of HSE measures.
Governments and companies can engage with local and regional industry, agriculture, and communities. Companies should closely collaborate with local government, industry, NGOs, and civil society to understand the hydrological conditions and regulatory frameworks within the river basin. This information allows for more accurate estimates of the cost, technology, and processes required to access water for shale development without displacing other users or degrading the environment.

Governments can increase investments in collecting and monitoring water supply and demand information. Robust baseline information and estimates of future water supply and demand and environmental conditions can help build a strong, shared knowledge base to inform the development of effective water use regulations.

A separate study on water resource assessment can be initiated that will provide a better sense of the dynamics.

Government of Pakistan can incentivize international companies to bring their international experts to Pakistan to develop the industry. Additionally, with collaboration of international companies, local institutes (such as, the Oil and Gas Training Institute) and universities can offer shale gas-specific courses. Service companies globally are involved in training E&P resources. DGPC can make arrangements with services companies to offer shale gas trainings and courses in order to build the capacity of local industry.
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Attachments:

- River Barrage Map
- Depth to Water Map
- Water Desalination Plant 8000 and 100000 cubic meter per day
- Sum Gas HCPV all four Formations
- Sum Oil HCPV all four Formations
- Simulated Production Profiles for 13 wells
- Desalination Economic Evaluation Program by IAEA, DEEP511