ENERGY POLICY PROGRAM

FINAL REPORT

PAKISTAN PETROLEUM POLICIES

REVIEW AND RECOMMENDATIONS

SUBCONTRACT EPP-C2-SC-004
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Acronyms

AEAI	Advanced Engineering Associates International, Inc.
DGPC	Directorate General Petroleum Concessions
D&PL	Development and Production Lease
ECC	Economic Coordination Committee of the Cabinet
EL	Exploration Licence
E&P	Exploration and Production
EWT	Extended Well Testing
FDP	Field Development Plan
HSE	Health, Safety & Environment
IRR	Internal Rate of Return
JV	Joint Venture
SOP	Standard Operating Procedures
G&G	Geological & Geophysical
GHPL	Government Holdings (Private) Limited
GOP	Government of Pakistan
LBG	Low Btu Gas
MSA	Model Supplemental Agreement
MPNR	Ministry of Natural Resources
OGIP	Original Gas in Place
OGRA	Oil & Gas Regulatory Authority
PCA	Petroleum Concession Agreement
PPEPCA	Pakistan Petroleum Exploration & Production Companies Association
PG	Performance Guarantee
R&D	Research and Development
ROFR	Right of First Refusal
ROI	Return on Investment
T&D	Transmission and distribution
USAID	United States Agency for International Development
WL	Windfall Levy

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EXECUTIVE SUMMARY

This report reviews the 2012 Petroleum Policy, Low BTU Gas Policy, Tight Gas Policy, and Marginal/Stranded Gas Fields Guidelines to identify the problem areas that are slowing down petroleum exploration and production activities in Pakistan. It also highlights the policy implementation impediments and makes recommendations for improvement of policies for effective implementation.

To effectively review the policies to identify the constraints, discussions were held with foreign, local, and state companies and the Policy/Rules Committee of Pakistan Petroleum Exploration & Production Companies Association (PPEPCA). In addition, a meeting was held with the regulator to obtain his views.

A number of themes emerged during the interaction with the stakeholders indicating common issues faced by the regulator as well as by the Exploration and Production (E&P) companies.

- **Clarity on Policies**
  The Consultant's overall review of the policies and interaction with the stakeholders clearly indicated that some of the provisions of the policies require clarification in order to remove the ambiguities causing bottlenecks in implementation. Although the Government's intent to incentivize the E&P companies to enhance the E&P efforts is quite evident from some of the provisions of the policy, greater clarity in the policies will help all the stakeholders and accelerate the implementation process. For example, stakeholders requested clarification regarding the provisions for 10% incremental production, marginal fields gas price, tight gas applicability for individual cases, definitions for tight gas and marginal fields.

- **Capacity and Implementation**
  This was identified as a double challenge because the limited resource capacity available to the regulator hampers the implementation of the policies and their application through the 2013 or earlier Rules. The regulator's limited capacity, which is due to various constraints (unfilled vacancies due to hiring freeze, technical experience, etc.), is seen by the E&P companies as significantly impacting the pace of exploration and production activities.

- **Life of Policy**
  Consultants are of the opinion that the formulation of policies frequently is not beneficial in achieving the government's stated desire to promote E&P activities as the industry needs to have consistency and longevity regarding what is on offer. Stakeholders echoed this view regarding life of policies. Following announcement of policy, sufficient time is needed for its clear understanding and impact. During the five-year period of 2007-2012, three policies (2007 Policy, 2009 Policy, and 2012 Policy) were announced as well as Tight Gas and Low Btu Policies, and Guidelines for Marginal/Stranded Fields. Generally, each policy

should remain active for at least 5-7 years and, if needed, amended instead of bringing in a completely new version. Another challenge the Consultants noted was lack of completeness of the Policies, for example, the 2012 Policy lacked a Model Supplemental Agreement for Conversion and some Policies lacked relevant rules for implementation.

A thorough review of the Policies was undertaken to identify issues impeding progress in their implementation. An analysis was carried out keeping in view the severity of the identified issues to make a workable way forward that enables regulator to implement the Policies effectively. Implementation of the Policies will certainly increase the confidence level of the E&P companies that currently are struggling to invest risk capital.

The 2012 Policy clearly reflects the Government's objective to incentivize the sector enabling the investors to enhance E&P efforts in the country. The biggest incentive is a higher wellhead gas price for onshore and offshore areas. The 2012 Policy Gas Price has also been made applicable to the incremental increase (minimum of 10%) in gas production from the existing fields. In addition, the windfall levy has been improved in favor of the E&P companies by reducing the Government share.

The Government was unable to pass the incentives of 2012 Policy to the producers in many aspects including gas price incentive on additional 10% production from the existing producing fields, clarity on the conversion package, clarity on transfer of work obligations from one block to another, extended well testing (EWT) period, and gas allocation system.

It is worth noting that two separate policies were introduced to offer incentives enabling the producers to exploit Tight Gas and Low Btu resources. However, implementation of these policies is a significant challenge due to vague definitions and eligibility criteria. Similarly, the provisions of the Marginal/Stranded Fields Guidelines require clarity to make these guidelines implementable.

An effort has been made to identify and address the issues with a view to accelerate the E&P activities to enhance the oil and gas production. Key recommendations from this analysis are:

- **Bring clarity to the individual Policy documents**. A total of over 40 issues have been identified. Recommendations have been made to provide clarity in the Policy documents. Some examples from the 2012 Policy include the basis for duration of EWT, incentives for incremental production, the bidding process, transfer of work commitment, the review of zones for pricing/work commitments, and relinquishment of areas. It is important to address the implementation challenges, such as policy gas price applicability to incremental production from the existing fields, as a great deal of confusion has been created due to lack of clarity. For example, the provision for selecting the threshold production level is not workable in some of the cases as the volumes in the development plan are not valid due to the changes over the life of the field. It is also not clear as to whether to use raw gas production or sales volumes, which are lower due to shrinkage factors resulting from gas processing, own use, and the level of inert in the gas. The recommendations also include the technical work to be included in the work units. This will enable the companies to claim the credit for undertaking such work and thus allow them to introduce new technology.

- **Provide clear definitions and eligibility criteria for Tight Gas, Low BTU Gas, and Marginal/Stranded Fields.** In addition, a legal framework needs to be developed to enforce these Policies. Appropriate recommendations have been made to remove the ambiguities for effective implementation of Policies.

- **Update Policies on a regular basis rather than announcing new policies**. This change would eliminate the challenges to both the regulator and the E&P companies in developing an understanding on the new policies.

- **Communicate information consistently to all stakeholders** by holding meetings and joint sessions with the regulator's team.

- **Carry out an organizational study of DGPC** to address the structural, staffing, and operational issues needed for improvement in the regulatory work flow given a significant rise in the number of operational Exploration Licences and Development and Production Leases. Such a study would also include the development and implementation of Standard Operating Procedures for routine regulatory matters where E&P companies deal with the regulator for various approvals, support, and implementation of agreed work programs. A capacity building plan should be developed for the regulator's office to ensure efficient and effective regulation.

1.PREAMBLE

The United States Agency for International Development (USAID) under an agreement with the Government of Pakistan is providing support to Directorate General of Petroleum Concession (DGPC) Ministry of Petroleum and Natural Resources (MPNR) through the Energy Policy Program (EPP), which includes a broad range of long-term and short-term specialized expertise consultancy in policy, technical, legal, regulatory, and operational aspects of the upstream oil and gas sector.

Advanced Engineering Associates International Inc. (AEAI) was contracted by USAID to manage the EPP Program. AEAI through a competitive bidding process selected the Petroleum Technology Solutions (PTS) to implement the upstream oil and gas program.

As a part of this work plan, PTS's Consultants held a series of meetings during September 2014 with stakeholders, including the regulator and E&P companies to exchange views and to identify issues concerning the Policies, rules, and regulatory impediments slowing down the development of the E&P sector. The focus was to review, evaluate, and make suitable and workable recommendations for the improvement of the existing Policies and rules in the overall interest of the stakeholders.

The EPP team participated in meetings held with the Consultants and companies and provided context and insight for this effort in addition to sharing AEAI's specific experience.

2. OBJECTIVES

The objectives of this work are provided below:

- Review the 2012 Petroleum Policy, Low BTU Gas Pricing Policy, Tight Gas Policy and Marginal/Stranded Gas Fields Guidelines, identify the problem areas and provisions not yet implemented that are slowing down the pace of petroleum exploration and production activities, and suggest recommendations for improvement of Policies for effective implementation.
- Analyse the over-regulation of the sector to suggest the need for deregulation where necessary. The issues such as delays in decisions, time limits, discretionary powers, penalties for minor offences/defaults, and independent appeal forum are also to be addressed.
- Suggest draft Rules for Policies where these have not yet been framed or recommend other course of action to provide the regulatory framework.

This report captures the effort undertaken where the focus was on review of the various Policies announced during the period 2011-12 (i.e., the 2012 Policy, the Low BTU Policy, the Tight Gas Policy, and the Marginal/Stranded Gas Fields – Gas Pricing Criteria and Guidelines). The detail of activity to be undertaken and the deliverable are listed below:

Activity: Discuss relevant policy documents with stakeholders (2012 Petroleum Policy, Low BTU Gas Pricing Policy, Tight Gas Policy, and Marginal/Stranded Gas Fields – Gas Pricing Criteria and Guidelines) to identify the problem areas and provisions not yet implemented that are slowing down development. Make recommendations for improvement and effective implementation of policies.

Deliverable: Report on the discussion with the stakeholders and findings covering the key provisions not yet implemented and problem areas of each Policy/Guidelines with recommendations as well as rationale for improvement and implementation of these Policies/Guidelines. The report is to cover the regulatory impediments that are slowing down the development.

3.METHODOLOGY

Currently, more than twenty-eight (28) Exploration and Production (E&P) Companies including sixteen (16) foreign, two (2) state, and ten (10) local companies are engaged in petroleum exploration and production activities in Pakistan. The E&P activities are being carried out under 176 Exploration Licenses (EL) and 157 Development and Production Leases (D&PL) spread in all four provinces of Pakistan.

Of these, the Consultants selected six (6) foreign, two (2) state, and two (2) local companies for interviews. This ensured that the Consultants had selected all the major players among foreign companies, both state companies, and two out of ten local companies that are undertaking significant activity. The companies selected for interviews hold ~70% of total exploration blocks and ~90% of the total D&PLs in the country. To cover the remaining E&P companies, the Consultants held meetings with the Secretary General of the Pakistan Petroleum Exploration and Production Companies Association (PPEPCA), an association representing the E&P companies and members of the Rules & Policy Committee of the PPEPCA.

Following the conclusion of the meetings with the E&P companies and PPEPCA, meetings were held with the regulator's team (Director General and Officers of DGPC) to gather their views on the Policies, rules, and regulatory matters. Consultants were also keen to understand the difficulties faced at the regulator's end for implementation of Policies and rules and the challenge of clarity for the directorate as it works to facilitate the stakeholders and regulate E&P activities.

Following is a list of the E&P companies contacted. These meetings were held between September 15 and 25, 2014:

- MOL Pakistan Oil and Gas Company B.V.
- OMV (Pakistan) Exploration Gesellschaft M.B.H.
- Petroleum Exploration (Private) Limited
- United Energy Pakistan Limited
- Oil and Gas Development Company Limited
- Mari Petroleum Company Limited
- Eni Pakistan (M) Limited S.A.R.L
- Pakistan Petroleum Limited
- China Zhenhua Oil Company Limited (did not make themselves available)
- BHP Petroleum (Pakistan) Pty Ltd (did not make themselves available)
- Other (PPEPCA - Policy/Rules Committee members)

3.1 Connect with Stakeholders

Structure of the connection with the stakeholders (E&P selected companies) was developed to identify issues in Policies, rules, and regulatory impediments. This exercise was essential for addressing the identified issues for keeping the interest of E&P companies operating in Pakistan alive, making the regulatory process efficient, and making new investment in Pakistan upstream petroleum sector attractive.

Consultants approached and interacted with each stakeholder listed in the preceding section keeping in view the various aspects covered by the policies, E&P activities carried out by the companies, and regulated by the regulator. This structure was devised to ensure that appropriate aspects of the policies and rules were discussed with the stakeholders and relevant queries were directed to appropriate companies in terms of their experience.

The strategy for conducting the individual meetings was as follows:

- Provide the context for the exercise being undertaken, i.e., review of Policies/rules and suggest necessary revision to remove bottlenecks and improve upstream regulation.
- Invite stakeholders to share their thoughts, concerns, and suggestions on Policies, rules, and regulatory issues.
- Prompt stakeholders through a set of questions to obtain additional feedback where necessary.

During interaction, the specific areas Consultants included in conversation with the stakeholders were as per Annexure 1. Notes from the meetings with individual stakeholders are attached as Annexure 2, including all the companies visited, PPEPCA, and the regulator.

4. IDENTIFIED ISSUES

Consultant's interaction with the stakeholders identified a number of challenges emanating from their understanding of the Policies' provisions, which resulted in issues of clarity and interpretation, as well as identified a need for providing clearer wording in the documents. The Consultants also identified a number of issues that need to be additionally addressed as the current guidance in the documents is either not sufficient or requires inclusion of specific provisions in order to bring alignment between all the stakeholders.

During the interaction with the stakeholders, a number of themes emerged indicating common issues faced by the regulator as well as the E&P companies. It was clear that significant focus was required to understand and address these areas to ensure quicker progress through an efficient regulatory process and to help companies keep their focus on delivering their committed work programs on agreed schedule resulting in reserve additions, production enhancement, and cost management.

Following were the themes identified by the Consultants:

- **Clarity on Policies**
  Consultant's overall review of all the Policies clearly indicated the challenge of clarity. There is a direct impact of clearly represented policy on the understanding of the same by the different stakeholders. From the Consultant's conversations with stakeholders, it was obvious that there is a glaring gap in the level of understanding of Policy provision by various stakeholders. A number of examples indicated that greater clarity and better articulation of clauses included in the documentation will help the stakeholders to be "on the same page" regarding understanding of Policies (e.g., 10% incremental production, Marginal Fields Gas price, Tight Gas price applicability for individual cases, definitions for Tight Gas and Marginal, etc.). Stakeholders were unanimous in requesting help in this area.

- **Capacity and Implementation**
  This aspect came up repeatedly crystallizing into a combined challenge where, due to the limited capacity available with the regulator, the implementation of the Policies and their application through the 2013 and earlier Rules was significantly hampered. The regulator's challenge of limited capacity is due to various constraints, including lack of technical experience and unfilled positions due to the hiring freeze and other factors. Stakeholders saw this aspect as significantly neglected as their issues were not being resolved, including those tied to the implementation of recent Policies. Their suggestions were for an organizational overhaul in the regulator's set-up that takes in to account the increased work flow through the regulator's office following the significant rise in the number of ELs and D&PLs and development and implementation of Standard Operating

Procedures (SOP) for many of the routine and regular matters managed by the regulator.

Consultants recommend development of a capacity building plan for the regulator's office as well as review of existing SOPs and development of new SOPs to cater for current needs.

- **No New Policy**
  Stakeholders echoed Consultant's view regarding the release of new Policies every few years. There should be a moratorium on new policy announcements at least for the next 5 years. Any change in the Policies for clarity and/or compatibility could be achieved by appropriate amendments to the existing ones. The Consultants consider that this will eliminate the challenges to both the regulator and the E&P companies to redevelop understanding of the new policies.

The issues identified by the Consultants and/or the stakeholders as they related to the 2012 Policy, Tight Gas Policy, Low Btu Policy, and Marginal Gas Fields Guidelines are discussed in Section 5 following. Section 5 also identifies the issues that need to be addressed by the Policy Implementation Committee.

5. REVIEW, EVALUATION, AND RECOMMENDATIONS ON ISSUES

The issues identified by the stakeholders and/or the Consultants are reviewed and evaluated and are followed by the Consultant's recommendation on the issue in this section. Issues related to each of the Policies and Guidelines are represented in Section 5.

5.1 Exploration and Production 2012 Policy

Issues identified by the Consultants and stakeholders related to the Petroleum Exploration and Production 2012 Policy are provided below:

Issue 1: Implementation of incentive on additional 10% production

Issue 2: Obligatory Relinquishment of Concession Area

Issue 3: Revisiting zoning of the prospective areas as represented in the Pakistan map attached to the Policy

Issue 4: Work units to be reviewed to include wider range of work types

Issue 5: Policy limits options for E&P companies.

Issue 6: Clarity on companies' ability to transfer obligations from one exploration block to another

Issue 7: Provide level playing field for all (Article 4.1.2.2)

Issue 8: All companies should have the same obligation to provide Performance Guarantees (PGs)

Issue 9: Bring Clarity to provisions in Article 6.5 on Performance Guarantees (PGs)

Issue 10: Extended Well Test (EWT)

Issue 11: Allocation system of gas commitments by Government of Pakistan (GOP) to gas utilities

Issue 12: Stakeholders facing significant issues with local administration due to lack of clarity around the term "Local employment" (Article 4.1.4)

Issue 13: Withdrawal by highest bidder post bidding

Issue 14: Should GOP contact the second highest bidder to match highest bid or re-bid the area?

Issue 15: Provision of E&P information disclosure needs clarity (Article 6.4.2)

Issue 16: E&P companies concerned whether or not they will receive the price offered in 2012 Policy.

Issue 17: Operator experience needs to be revisited (Article 2.04)

Issue 18: Changes to fiscal package (last paragraph of Article 4.0) to be deleted

Issue 19: Article 13.9 is not relevant

Issue 20: Errors in Annexures 7, 8, and 9 of the Policy to be addressed

Issue 1: Implementation of incentive on additional 10% production

There is significant ambiguity post the Amendment to Article 13.8 of 2012 Policy as gazetted in 2013.

> *"13.8: The gas price of 2012 Policy will also be extended to the entire incremental gas production, subject to meeting the minimum threshold of 10% addition in the current production or the volumes committed in approved development plan, whichever is higher. For this purpose the current production will mean maximum gas production of any day during last six months immediately preceding the date of approval of this Summary by the CCI i.e. 31st July, 2013. The producer will be required to produce third party certification that the said activities will not adversely affect the total recoverable reserves or damage the reservoir as a whole. The third Party Consultants will be appointed by Ministry of Petroleum and Natural Resources for which cost will be borne by the concerned E &P Company."*

Review, Evaluation, and Recommendation

The above clause needs to be revised in a manner to remove the ambiguity and define how it will work in practice. Presently, it is being interpreted in at least three different ways by the stakeholders (i.e., the companies, the regulator, and the gas transmission companies who ultimately make the payments). The companies' concern was that because of lack of clarity, the objective of increased gas production is not being achieved.

The Consultant's opinion, based on a review of the Amendment, is that it needs additional clarification in the following areas:

- **Is conversion to the 2012 Policy a pre-requisite for obtaining this benefit?** On the premise that the policy makers deliberately included this incentive within the section of "Conversion", it is presumed that regulator may be inclined to the interpretation that this incentive would be applicable to only those E&P Companies that opt for conversion, as this benefit is provided as part of the 2012 Policy. Whereas, the E&P companies are inclined to interpret that this benefit, as per 13.8, has also been extended to the entire incremental gas production from any field.

Recommendation: Consultants believe that the intent of this benefit is to encourage E&P companies to make extra effort to bring additional gas in to the gas transmission network system. Therefore, it is recommended that this benefit may not only be restricted to conversion option and should be made applicable to all the gas producers to achieve the objective of enhanced production.

- **Production vs. sales:** The clear intent of the regulator is to increase the amount of gas injected in the transmission and distribution systems. Hence sales volume, and not production, is the more pertinent consideration. Additionally, the buyer of the incremental volumes would be the Transmission & Distribution (T&D) companies, whose only reference is the sales volume.

  Recommendation: Compare previous period sales volumes to the new sales volumes to determine incremental sales as that would be a more fair and apt comparison.

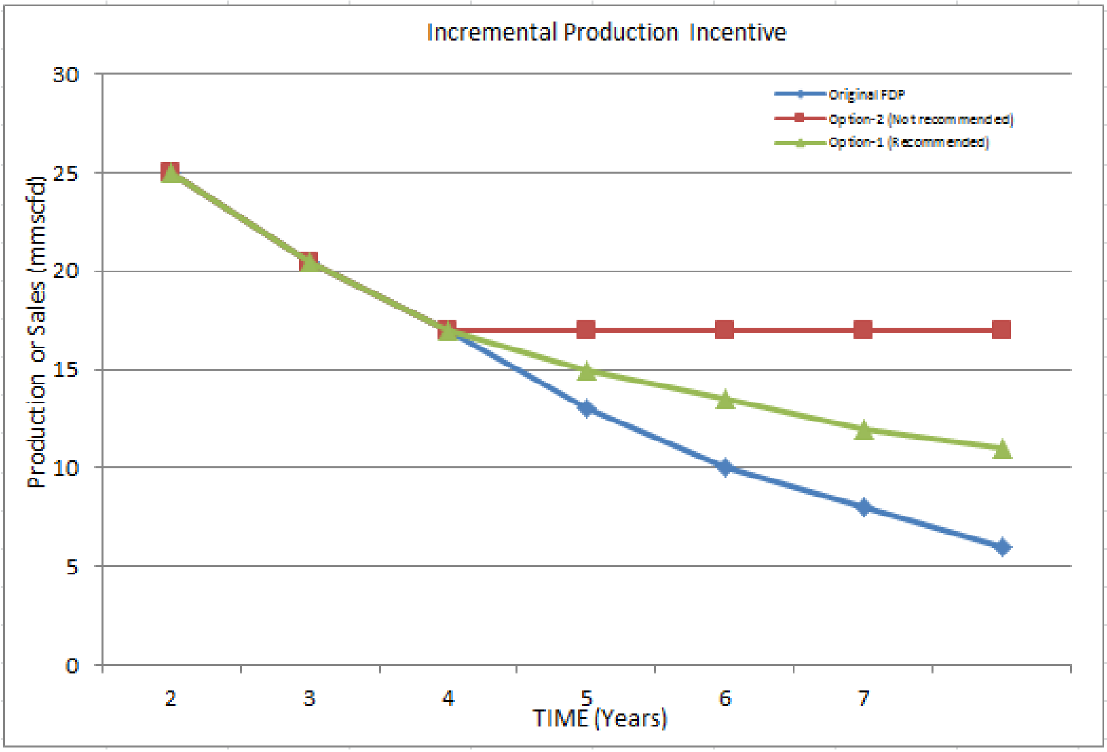
- **Six months' caveat.** Further clarity on the reference threshold of gas volume for achieving the incremental price during the producing life of a field, i.e. basis for using Field Development Plan (FDP) or last 6 months' highest daily rate (whichever is higher).

  Recommendation: The 6-month period should not be limited to a specific period of time, which is the February 2013 to July 2013. In addition to the 6 months prior to the announcement of 2012 Policy, this incentive should also be open to any 6-month period after the announcement of 2012 Policy for companies to be able to not only benefit from this but also to achieve the key objective of the clause, which is to increase gas production (and resultantly, sales volume) from existing fields without damage to the reservoir. For future FDP submissions, all gas producers should be asked to include projected gas sales along with projected production. Where FDP is not available for the last 6 months, sales may be used as reference for comparison.

- The Policy needs to provide reasoned and practical reference points for determination of the volumes on which the incentive price will be applicable. The current limitation of the time period mentioned, i.e., Feb.-July 2013, appears to be an arbitrary reference for the current production and would have to be removed from 13.8.

  Recommendation: Reference production (and sales) to be used for determination of incremental volume should be from FDP's relevant year and not a 10% increase from when the benefit is claimed, i.e., if FDP sales in 2015 are projected to be 10 MMCFD and in 2016 it is 9 MMCFD, then the determination of the incremental volume threshold should be a comparison with the yearly number represented in the FDP. In such an instance, the comparison should be between the projected sales with the actual sales, as opposed to 10 MMCFD perpetually. This aspect will also require further consideration on how the FDP needs to be represented by companies at the time of submission to the regulator as it would form the basis of any subsequent incentive that they may want to claim. DGPC should also prescribe such provisions for the FDP so as to ensure that such an incentive is not exploited by the companies. The acceptance of the incentive request by the regulator should require a third-party certified update of the FDP (including well/field production/sale potential) that should incorporate the historical reservoir performance and future activity plan so as to get a reference future production and sales profile.

Figure 1. Secenarios for an Incentive Price Claim by Companies



Error! Reference source not found., above, represents the two possible cenarios (Option-1 and Option-2) for an incentive price claim by companies for incremental production. The Consultant recommends that Option-1 should be used for comparison of the new production rate achieved by companies with the rate for the last six months (or the rate represented in the FDP, if available). The Consultants also assert that expecting the companies to maintain the enhanced rate, equal or greater than 10% of last 6 months or FDP comparison for that year is unrealistic. Hence, Option-2 shown in Figure 1 is not the recommended path to follow, if the intention of the clause is to give a real incentive to the producer for enhancing production and increase gas injection in the system. It must be asserted here that the key aspect to govern this incentive is that the companies originally submit a reasonable and authentic FDP at the time of applying for a D&P lease. A third-party certification, at the time of claiming the benefit of this incentive, is strongly recommended to ensure that the regulator has enough data to keep operators in compliance.

Issue 2: Obligatory Relinquishment of Concession Area

Companies had a number of observations on the requirement to relinquish the licence area under the EL. Most of the E&P companies suggested to either eliminate the requirement to relinquish area or reduce the percentage of area to be relinquished.

> *"3.1: Maximum 2500 km^2 with subsequent progressive area relinquishment of 30 % of original area after Phase-I of initial term, 20% of the remaining area after Phase II of initial term of 10% of the remaining area on or before the start of second one year renewal"*

Review, Evaluation, and Recommendation

Whereas no relinquishment or a lower percentage of relinquishment by the companies would provide them the continuity and ability to retain the entire area or larger percentage of area for exploration for a longer duration of time, the current arrangement helps the regulator to keep the pressure on the companies to undertake E&P activities efficiently. Consultants see merit in both options and believe that both options can be conflated with certain caveats to make it more productive and practical. Companies may be permitted to retain the licence area, provided they offer additional work program for keeping the area. Through this arrangement, while the regulator is able to obtain additional work commitment from the companies, it gives the companies the option to retain the entire area in case they find the total area to be of interest.

Consultants recommend that in order for the companies to continue to keep entire area without relinquishment after Phase 1, they should commit additional work units equivalent to 30% of the committed work units of Phase 1 as per the signed PCA and modify Article 3.1 of the Policy accordingly. Similar logic is recommended for Phase 2 and subsequent renewals, i.e., additional work units equivalent to 20% of committed units for Phase 1 for keeping entire area during Phase 2 and applying the same logic for the renewal periods.

Additionally, it would be appropriate to make this change for both onshore and offshore areas. Figure 2, below, indicates the current situation for relinquishment and Figure 3 is the proposed amendment. However, it is reiterated that the proposal in Figure 3 is suggested as an alternative to the current arrangement, and not as a replacement.

Figure 1. Current Mandatory Relinquishment

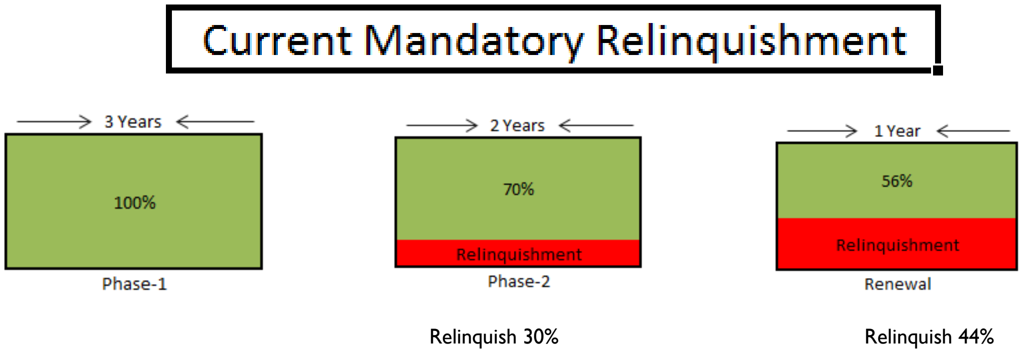
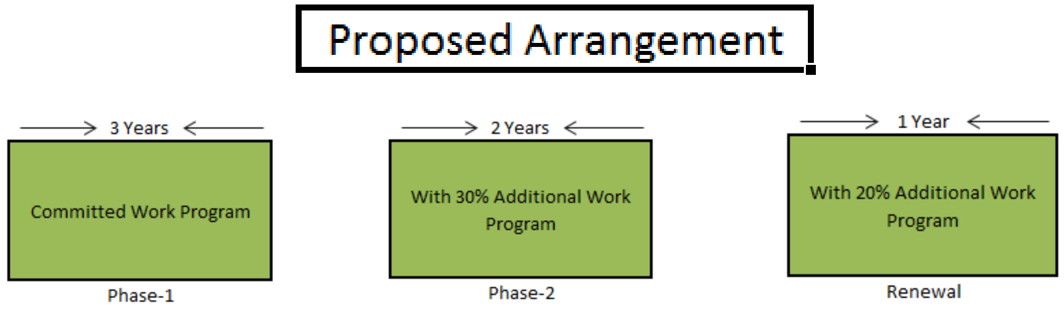


Figure 3. Proposed Amendment



Issue 3: Revisiting the zoning of the prospective areas as represented in the Pakistan map attached to the Policy

The Consultants consider that this aspect needs to be addressed in the Policy.

Review, Evaluation, and Recommendation

The zoning map currently represented in the 2012 Policy was developed approximately 20 years ago. The Consultants understand that the zones were carved out on the following basis:

- Level of exploration risk;
- Discovery/success rate;
- G&G/well data available based on past activity in the zone;
- Availability/proximity of infrastructure; and
- Area hardships and security situation.

Since first defining these zones in the 1994 Policy, all of the above factors have changed substantially. However, the 2012 Policy document inexplicably is still using the old zoning map. Zoning plays an important role in policy incentives, such as price, obligations, work unit equivalence, and work commitment varies with the zone.

The Consultants recommend that this map be reviewed and necessary changes in zonal boundaries be made, considering the aforementioned factors and the current situation on the ground after utilizing all G&G/infrastructure information obtained over the last two decades (e.g., impact of TAL/Nashpa in KPK). It is understood that an updated draft was developed in 2011, which may be used as a starting point to progress with this recommendation.

Additionally, in 2012 Policy, the same type of activity has been assigned different equivalence in terms of work units for different zones. As the situation has changed considerably over the last 20 years, Consultants recommended revisiting this rationale to bring clarity to this key aspect of work commitment for awarding petroleum rights and work commitments. This is also important when companies look to transfer their work commitment from one block to another block in different zones, in case they could not identify drillable prospects in their existing blocks. The above recommendation should be progressed in consultation with industry. Regardless of the final decision on this recommendation, it is suggested that GOP honour the already signed agreements (for blocks awarded in 2013 post the 2012 Policy). The new zones should be applicable to the next bidding round.

Issue 4: Work units need to be reviewed to include a wider range of work types.

Companies are keen to have other types of activities included in satisfying the work unit requirements committed by them as part of the bid and work program. Consultants agree with the concern and represent their views in the below evaluation and recommendation.

Review, Evaluation, and Recommendation

The 2012 Policy under "Concept of Work Units" contains types of work that are translated in equivalent work units. A work unit is used for measuring the compliance with the minimum work obligation. Currently, the Policy covers certain types of works. In the Consultant's opinion this suggestion is worth consideration as active Research and Development (R&D) work in the petroleum upstream sector is continuously resulting in emergence of new technologies and techniques, which after field tests, are recognized internationally. It is recommended that the regulator is authorized to make changes in the work unit concept from time to time on the basis of recommendations of PPEPCA with appropriate GOP approvals.

The Consultants understand that MPNR is moving a summary for approval to include certain new G&G technologies in the list of types of works in the 2012 Policy. To avoid the difficulty of getting each new technology approved for inclusion on a piecemeal basis, the Consultants also recommend that a criteria for types of work may be included in the 2012 Policy, which if met by any new technique that meets international standards and would not cause any harm to the environment or compromise the hydrocarbon reserves, may become eligible to be considered as an approved type of work. For determination of equivalence in terms of work units for this new technique, PPEPCA recommendations supported by field cost data may be used for equivalence

Issue 5: Conversion to 2012 Policy limits options for E&P companies

According to the Policy, companies can either convert to the 2012 Policy or Tight Gas/Low Btu Policies. Consultants consider that this key aspect needs to be addressed in the 2012 Policy.

> *"Those E&P companies who opt for conversion to this policy would not be entitled to tight gas policy and/or low BTU policy."*

Review, Evaluation, and Recommendation

Clause 6.1.7, as quoted above, inexplicably limits the companies to convert to the 2012 Policy even if they have (or are likely to have) a Tight Gas or Low BTU Gas discovery. This limitation is not understandable given the GOP's desire to encourage exploration activity for all categories of resource (conventional and unconventional). In the Consultant's opinion it is not rational and appears to be arbitrary to deny application of Tight Gas or Low BTU Gas Policies on Tight Gas/Low BTU gas discoveries in a concession where a company has opted to convert to the 2012 Policy. It should be noted that the 2013 Model PCA Articles 6.15, 10.4 (iv) and 23.6 provide the appropriate incentives to the producers in case they discover Low Btu or Tight Gas. The Consultants believe there is no logic to denying the applicability of each policy to E&P companies depending on the nature of discovery.

The Consultant's recommendation is therefore to delete this Article.

Issue 6: Clarity on companies' ability to transfer obligations from one Exploration Block to Another

This should be irrespective of whether the exploration licence is in Phase 1 or Phase 2 or in different zones. This recommendation is included here based on the case files examined by the Consultants during their advisory support on technical, commercial, and regulatory issues to the regulator's office.

The concept should be to keep GOP whole in the delivery of the committed work units, i.e., that the level of committed risk capital or seismic and drilling activity takes place. DGPC should not impose any restrictions where the E&P companies are willing to transfer their obligations from one exploration block to another, subject to reasonable justifications. The purpose should be to encourage exploration activities, rather than to penalize companies and receive compensation ($10,000 per work unit) from the companies for not having done the committed work in a concession area.

The ability to move commitments would allow companies to discontinue work in the awarded concession if evidence suggests (based on relevant technical work in the area) that it is not prospective. This flexibility should therefore keep the work units commensurate with the risk profile represented in the regulator's equivalency tables in Annexure 5 of the 2012 Policy, enabling the companies to transfer their work obligations between different zones, as identified in the regulator's map and equivalency tables. Such flexibility would adequately take care of the calculation to determine work units required in the area where the responsibility is being transferred. Further clarity will need to be developed for the above situation in case of JV partners who may want to transfer their obligation, equivalent to their working interest, to different areas in a zone of their choice.

The Consultants recommend that this flexibility may be clarified in the 2012 Policy as it will ensure that risk exploration capital committed by each working interest owner is preferably spent on exploratory activity rather than parties making payments as compensation for non-fulfilment of work obligations to the regulator. It is important that the companies requesting this change be allowed to choose the area they want to transfer this obligation to, rather than being directed to an area suggested by the regulator. Choice should, therefore, be left with the company looking to spend the risk capital.

Issue 7: Provide level playing field for all (Article 4.1.2.2).

> *"4.1.2.2: GHPL/Provincial GHPL will not pay the production bonuses as long as GOP/Provincial Government is the majority shareholder of this company."*

The Consultants considered the above provision to be unfair to the other E&P companies and believe it needs to be addressed.

Review, Evaluation, and Recommendation

During advisory support to DGPC, Consultant became aware of cases needing clarity regarding payment of production bonus. The view of companies other than state owned was that they are liable to pay a production bonus corresponding to their working interest. The Consultants understand that the regulator's point of view on this issue is that as GHPL/PHC and OGDCL are exempted, therefore the total amount of production bonus as specified in the Policy would be paid by the remaining working interest owners on a prorated basis.

To provide equal conditions for all parties and to address the ambiguities involved, the Consultants recommend deleting Article 4.1.2.2. All working interest owners will then be liable to pay the production bonus, including GHPL, PHC, and OGDCL. This deletion will also ensure that local population of the relevant area is not deprived of their full share of funds for development when all JV partners in the area pay their due share.

Issue 8: All companies should have the same obligation to provide Performance Guarantees

This includes state companies to ensure a level playing field for bidding and subsequent award of ELs.

> *"3.2.1.8: Award of petroleum rights to Pakistani state owned companies will also be subject to the same process mentioned herein above."*

Review, Evaluation and Recommendation

A number of companies raised the concern that the state-owned companies enjoyed certain advantages such as not needing to provide Performance Guarantees (PGs) for the areas they bid for (being state-owned companies). If this is correct, it gives the state-owned companies an unfair commercial edge, both while bidding and subsequently at signing of new blocks. In this situation, they can make any commitment without providing a corresponding PGs (as required in Article 6.5) and hence avoid all related financial costs and any resultant impact to their ability to borrow from (or disclose as per equity market requirements to) the market. Article 3.2.1.8 only states that the bidding process is equally applicable to the government owned companies and does not extend to cover the above mentioned concern.

The Consultants recommend that this should be clearly defined in the policy, i.e., state-owned companies will also provide the necessary guarantees, the same as other bidders, to ensure a level playing field for all.

Issue 9: Bring clarity to provisions in Article 6.5 on Performance Guarantees

The concern here is whether each of the options offered in Article 6.5. (1 to 5) provide the regulator with the same level of financial/contractual comfort. It appears that sub-sections 1 and 5 require a bank guarantee or escrow for 25% of the value of the work commitment whereas sub-sections 2, 3, and 4 require either a Parent Company Guarantee, or a lien on production or assets.

Consultants consider this aspect needs to be addressed in the Policy and clarity provided accordingly.

> *"6.5 (1 to 5): DGPC shall require successful applicants for petroleum exploration licences to furnish, in an acceptable form, a guarantee or guarantees, with respect to its work commitments on or before the execution of the petroleum exploration licence. In the event, the successful applicant elects to provide any guarantee other than a Parent Company Guarantee during exploration phase, the guarantee so provided would only be released in case all work obligations including but not limited to social welfare, training, data, rental etc. are fully discharged.*

DGPC reserves the right to deduct payment for non-performance of all such obligations from the performance guarantee.

- *Bank guarantee equal to 25% of the minimum financial obligation from a bank of international repute acceptable to the Government on the prescribed format in PCA/PSA.*
- *Parent Company Guarantee of a multinational exploration and production Company of international repute with a proven track record or a corporate guarantee of a local exploration and production company having Operatorship with majority working interest in a producing field within Pakistan against its own financial commitment.*
- *Petroleum production lien equal to 100% of the minimum financial obligation.*
- *First and preferred assets lien equal to 100% of the minimum financial obligation.*
- *Escrow Account equal to 25% of the minimum financial obligation in a bank of international repute acceptable to the Government."*

Review, Evaluation, and Recommendation

While the logic of providing these options can be understood, they do not provide the same level of financial cover or comfort to the regulator. Therefore, this adds a risk for GOP if a company was to select the option provided in clause 6.5.3 or 6.5.4. There is no clarity on how the Government can actually recover any monies in case of default by a successful bidder and EL holder. This is because there is no valuation mechanism that the regulator can employ that ensures it is financially covered for the value of the obligation. Furthermore, in case of either clause 6.5.3 or 6.5.4, the value of what can be recovered by the GOP diminishes from the day it is offered (assuming on-going production from the reserves, asset pledged, or depreciation of assets due to usage of equipment). It is also important to differentiate between resources and reserves when this particular option is used for a lien. Hydrocarbons that cannot be produced economically at the time of their pledge should not be part of the pledge as they are resources, and not reserves.

Another aspect to be addressed, which was identified by some companies, was the fulfilment of obligation of each JV partners in case of default by one of the partners given that the JV is jointly and severally responsible to deliver the work program. In this situation the remaining partners may be unduly burdened to the extent of the non-paying party's working interest.

The Consultants recommend that these options are re-visited and clarified so they offer the GOP the necessary comfort that the companies are providing adequate financial cover that is required at all times, as well as give protection to remaining partners in case of a default from one of the parties in the JV. There should also be a provision that the guarantee values are periodically (say, yearly) revised downwards as E&P companies continue to reduce their work commitments through discharge of their obligations.

Issue 10: Extended Well Test

The Extended Well Test (EWT) provision does not adequately explain some of the mentioned points that are to be clarified keeping in view the essence of the basis on which this provision has been incorporated in the Policy. This would ensure its appropriate application using technical justification while requesting the regulator for such a grant. The regulator should have the necessary (complete) information to justifiably grant the period requested for the EWT and the management of associated challenges of flaring, production bonus payment, and so forth.

"*4.1.6: Extended Well Testing:*

- *Subject to approval from DGPC, an Operator may be permitted to undertake extended well testing (EWT) during the appraisal phase and before declaration of commerciality and approval of the development plan. Such approval will be granted provided that the Operator inter-alia complies with the requisite royalty, tax, rentals, and training/social welfare commitments as applicable under the lease.*
- *A request for approval of EWT (including associated temporary production facilities) will be made to DGPC providing information with regard to (a) technical justification for EWT; (b) proposed duration for EWT and (c) a plan with regard to disposal of gas during the proposed EWT period. The duration of EWT will be allowed keeping in view the reservoir uncertainty and the proposed investment outlay on EWT. DGPC will not grant approval to undertake flaring for EWT for a period longer than 30 days, unless under exceptional circumstances.*
- *Where the specification and quality of the gas from an approved EWT is acceptable to the buyer, the gas price shall entail a 5% discount from the applicable gas price for on spec gas and 10% discount for off spec gas for that Zone.*

The facilities that are required to undertake EWT shall be constructed and operated in accordance with good international oilfield practices."

Review, Evaluation, and Recommendation

The provision of EWT period that allowed the companies to sell the gas during testing was introduced to facilitate the E&P companies for the purpose of properly testing the reservoir and well potential. However, some of the fields on EWT have been producing for significant periods (in certain cases up to many years) without following the regulatory requirement for submitting a lease application. Such an act is construed to be an attempt by the companies to generate revenues without exposing themselves to the obligations due under the D&PL.

The Consultants recommend limiting the EWT period to the purpose it was intended for, i.e., understanding the potential of the well and reservoir. Therefore, the total volume allowable to be produced during the EWT period may not exceed 10% of Original Gas in Place (OGIP), with further technical assurance on this issue coming from a reputable independent reservoir consultant. It is also recommended to consider that the regulator receive the applicable production bonus once the total revenues for the producers from sale of gas exceed $6 MM during the EWT.

Figure 4. Extrapolation and Actual Production

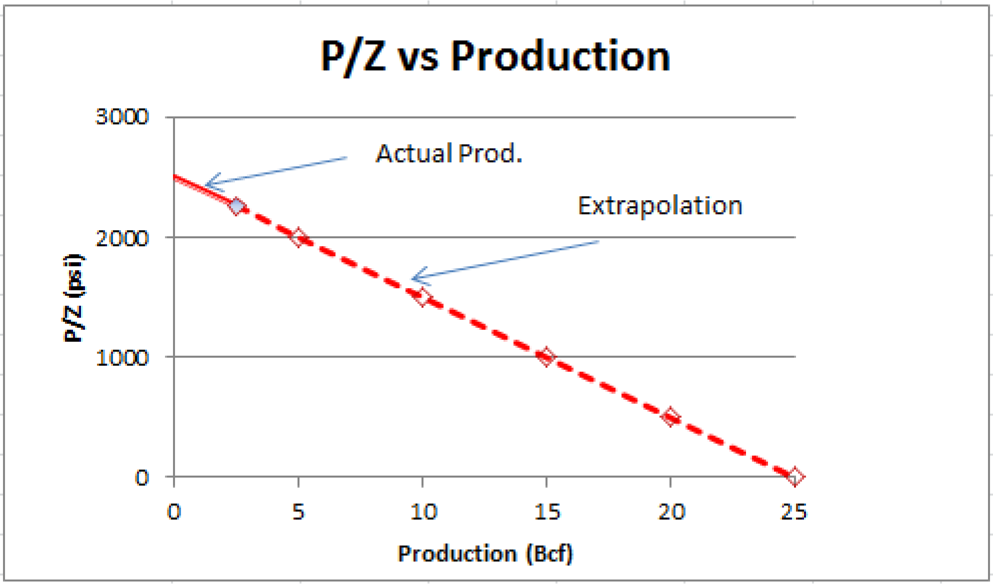


Figure 4 above shows a P/Z plot where the actual production is ~2.5 Bcf out of a calculated OGIP of 25 Bcf (the dotted line is an extrapolation of the plot based on actual performance to date). This actual production is recommended as the maximum production allowed for an EWT so that companies do not continue to produce for a long period without getting an FDP approved by the regulator to optimally develop the field. Technical justification for a longer EWT period can always be provided through a third party in complex cases where such justification requests additional time to continue the EWT for specific technical reasons.

Issue 11: Allocation system of gas commitments by GOP to gas utilities

This provision in the policy allows the producer to sell 10% of their share of gas production to third parties with prior consent of the provincial government, which, instead of offering any incentive to the producer as intended by the policy, is restrictive.

> *"9.4.2: Subject to overall market demand, E&P Companies may request and GoP will purchase 90% of their share of pipeline specification gas through a nominated buyer which is effectively controlled by it in acceptable daily, monthly and yearly volumes to meet the internal demand in an economical manner provided there are no infrastructure constraints. The E&P Companies shall have right to sale 10% of their share of pipeline specification of gas to any buyer with the prior consent of the Provincial Government. The delivery point shall be at the outlet flange as outlined in paragraph 9.3 (above). GoP/gas buyer nominated by GoP shall pay the price for gas at the outlet flange as set out in this Policy. In addition, the "guaranteed percentage" for foreign exchange remittance as contained in sub paragraph 9.2.2 above will apply to such sales."*

Review, Evaluation, and Recommendation

The wording of Article 9.4.2 gives two confusing messages. In the first part, it binds the GOP to purchase 90% pipeline specification gas if so requested by the producers. Whereas in the second part, it says that producers have the right to sell only 10% of pipeline quality gas to any buyer with the prior consent of the provincial government. These parts contradict each other resulting in a confusion that requires clarification on the rights and obligations of producers and the role of the Government to sell or buy pipeline quality gas produced.

The Consultants recommend that Article 9.4.2 be made more explicit by clearly identifying that producers shall be free to sell 90% of their share of production of pipeline quality gas to any buyer. However, if producers offer to GOP up to 90% of their share of production of pipeline quality gas, the GOP will purchase it through a nominated buyer, which is effectively controlled by it in acceptable daily, monthly, and yearly volumes to meet the country's internal demand in an economical manner provided there are no infrastructure constraints. For the remaining 10% of their production of pipeline quality gas, the producers can sell to any buyer with the prior consent of the Provincial Government. In other words, producer will only require prior consent of the Provincial Government for 10% of the share limiting the role of Government in such a scheme of work. The idea of 10% control resting with the Provincial Government also requires rationale in the scenario where the producer offers 100% of the production to GOP.

This recommendation is based on promoting free market principles while the GOP will benefit from the Wind Fall Levy and higher taxes when E&P companies sell their share at higher than GOP offered prices.

Issue 12: Stakeholders facing significant issues with local administration due to lack of clarity around the term "local employment" (Article 4.1.4)

> *"4.1.4: Local employment, training and social welfare obligations will be applicable as per Annexure-3."*

Review, Evaluation, and Recommendation

Article 4.1.4 uses the term "local employment" in the main body of the Policy, but for its applicability it refers to Annexure-3. According to Annexure-3, companies are required to get DGPC's agreement on their annual employment program for Pakistani nationals. In our opinion there is a need to provide clarity for this issue.

The consultants recommend that Article 4.1.4 be modified to clearly spell out that for positions of professional, technical staff, and secretarial staff, the requirement is for Pakistani nationals and for unskilled labour the requirement is for locals from the concession area. This will be in alignment with what has subsequently been represented in the 2013 Rules.

Issue 13: Withdrawal by highest bidder post bidding

The policy has no provision for a penalty if the highest bidder withdraws after being successful in a bid round. Consultants consider this aspect needs to be addressed in the Policy.

Review, Evaluation, and Recommendation

The current process does not require a bidder to provide a bank guarantee or surety commensurate to their bid. In case the highest bidder walks away, there is no mechanism that allows the regulator to penalize the bidder to compensate for non-performance of its bid. This leaves the regulator with the task of re-initiating the bid process for that area along with the cost and time required (for both the regulator and other interested parties) besides delaying the execution of exploration activity for the area.

It would, therefore, be appropriate to devise a mechanism to ensure that the successful bidder will progress their bid to signing the PCA. It will also reduce an opportunity for collusion in the bidding process by parties seeking to collude by submitting a low and a high bid for an area.

It is recommended that in case of non-performance the highest bidder should be disqualified from the next three (3) bidding rounds and should be barred from forming any JVs or executing any Farm-in/out Agreements for any of the blocks being bid in that bidding round.

Another option that may be considered is instituting a bid bond (for say $100K) to ensure penalizing a successful bidder in case of failure to proceed to execute the PCA.

Issue 14: Should GOP contact the second highest bidder to match highest bid or re-bid the area?

Consultants consider this aspect needs to be addressed in the Policy.

Review, Evaluation and Recommendation

The 2012 policy is silent on this aspect. According to prevailing practice with the regulator if the highest bidder walks away then the second highest bidder is asked to match the highest bid.

Consultant's recommendation is that the second highest bidder be awarded the bid on the basis of their work program. The argument to support this recommendation is that each bidder for an area would be making the offer on the potential of the area and the evaluation/risk assessment by each bidder would have been done prior to making the offer. It may therefore be a significant stretch to match the highest bid for the second highest bidder from a number of perspectives that could include ability to deliver a bigger work commitment and the related financial impact. In case of declining the request to match by the second highest bidder the exploration activity desired by the regulator will be delayed.

Issue 15: Provision of E&P information disclosure needs clarity (Article 6.4.2).

The Consultants considered this aspect needed to be addressed in the Policy.

> *"6.4.2: Operators and Contractors have the obligation to provide DGPC with relevant information related to exploration and production activities.*
>
> *DGPC will disclose information into the public domain except according to the following conditions:*
>
> - *Operational information: daily, monthly and annually.*
> - *Commercial & financial information: after five years, except commercial sensitive information which may give unfair advantage to third-parties."*

Review, Evaluation, and Recommendation

Article 6.4.2 of the 2012 Policy puts certain conditions for DGPC to disclose in public domain information gathered from E&P companies. In the Consultant's opinion both these conditions require elaboration. The first condition is not considered to be an exception to the disclosure as it is not clear to withhold or disclose such information, whereas the other condition uses the term "commercial sensitive" information that is too broad and should be clearly stated. The Consultants recommend revisiting this Article to bring the required clarity.

Issue 16: E&P companies concerned whether or not they will get the price offered in the Policy

Review, Evaluation, and Recommendation

Consultant's received this comment from some of the companies apparently emerging from some past experience with reference to realization of oil and gas price provided under the 1994, 2007, and 2009 Policies. In addition, delay in formulation and approval of Model Supplemental Agreement (MSA), a pre-requisite for eligibility of E&P companies to achieve the 2012 Policy incentive package, has also raised an element of mistrust.

The Consultants recommend that the process of approval of MSA should be expedited on a fast track basis to address this trust deficit. In the future, such mechanism for conversion option should be provided in the Policy with the MSA being a part of it to save time, effort, and frustration in realizing the incentives offered under the Policy to stakeholders in a timely manner.

Issue 17: Operator experience needs to be revisited (Article 2.04)

> *"2.0.4 All companies having joined a consortia of companies in a concession and have gained at least three years of experience as a non-operator will be eligible to become operator subject to demonstration of technical and financial capability."*

The Consultants considered this aspect needed to be addressed in the Policy.

Review, Evaluation, and Recommendation

The purpose of this Article is to ensure that operatorship is given to companies having past operatorship experience. Consultants fully endorse this approach but want to point out that it excludes those new local companies having a team of professionals with substantial managerial experience of working for reputable international operators.

To cover such situations, the Consultants recommend that Article 2.04 of the 2012 Policy be updated with provision for operatorship by a new local company that has a team with substantial managerial experience (i.e., past working experience for an international operator) and financial resources to undertake the E&P activities diligently. The key assurance that the GOP should look for is whether the proposed operator has the staff capable of developing appropriate technical, operational, planning, HSE, and financial systems based on the experience available to the operator's management and professional team as well as the financial strength to carry out risked exploration activities.

Issue 18: Changes to fiscal package (last paragraph of Article 4.0) to be deleted

> *"4.0 (Last Paragraph): The onshore fiscal package contained in this Policy as applied to future awards will be reviewed from time to time in the light of additional information and may be adjusted to maintain international competitiveness."*

The Consultants considered this aspect needed to be addressed in the Policy.

Review, Evaluation, and Recommendation

Most probably the intent of last paragraph of Article 2.0 is to improve the fiscal package; however, in the current form it dilutes the assurance from GOP about the fiscal package contained in the 2012 Policy for future awards. In the Consultant's opinion it is not an appropriate message. Policies are not for one bidding round and are meant to cover all future awards until modified or when a new Policy is announced. It is also noted that this provision is not provided in Article 5 (Offshore PSA), which is appropriate.

Therefore the Consultants recommend that last paragraph of Article 4.0 of 2012 Policy be deleted.

Issue 19: Article 13.9 is not relevant

> *"13.9: The first right of refusal will be granted to the company who has quoted the lowest rate for supply of rig during last five years in the award of contract for drilling rigs by JV partners."*

Review, Evaluation, and Recommendation

This article does not belong in the Policy document and may have been inadvertently included. The Consultants recommend deleting Article 13.9 from the 2012 Policy.

Issue 20: Errors in Annexures 7, 8 & 9 to be addressed

Review, Evaluation, and Recommendation

Change is required as Zone 1 is referenced at the bottom of the tables for Zone 2 and Zone 3. The Consultants recommend fixing these errors (typos) in Annexures 7, 8 and 9 of the Policy.

5.2 Marginal Field Guidelines

A list of issues identified by the Consultants and the stakeholders as they related to the Marginal Gas Fields Guidelines is provided in this section.

Issue 1: Definition for Marginal Field needs clarity

Issue 2: Applicability of Marginal Price limited to Reserves Indicated as part of Marginal Classification

Issue 3: Change 'at commercial rates' to 'economically'; further clarity is needed for E-1(iii)

Issue 4: Marginal Gas Definition in the Guidelines: Reference should be removed

Issue 5: Delivery Point needs further clarity (Section N)

Issue 6: Bring clarity to re-grant option (Section O)

Issue 7: Correct base price number to US $ 6/MMBTU (Section J)

Issue 8: Section *H (Retention Period) provision is too liberal*

Issue 9: No standard Policy implementation committee provision (Section P)

Issue 10: Oil Field size equivalence

Issue 1: Definition for Marginal Field needs clarity.

As per Marginal/Stranded Gas Fields Guidelines, 'The Marginal Field' or 'Marginal Discovery' means a field that is uneconomical for development (including re-development efforts like infield drilling) and production using current technologies based on the terms of the current Petroleum Concession Agreements applied to the size of the reserves.

For further clarity a marginal field is defined as an oil or gas reservoir that cannot be exploited economically under the existing E&P Policies, pricing structure and available technologies.

Marginal Fields shall be categorized as under:

- Reservoir size of Stranded Fields for Zones (Zones as marked in Petroleum 2012 Policy)
  - Zone I – [25] Bcf
  - Zone II – [20] Bcf
  - Zone III – [15] Bcf

(For Oil discoveries the above gas volumes will be converted in equivalent oil barrels)

- Reservoirs that are certified to be compartmentalized and where the size of the individual compartments is smaller than the reservoir size mentioned herein above (and the compartment cannot be exploited economically under the existing E&P Policies, pricing structure and available technologies).

- Depleted Fields already nearing the end of economical production life requiring secondary / tertiary recovery methods.

The Government may also approve a field or discovery as Marginal taking into consideration the following:

- Initial well productivity
- Recoverable volume
- Lack of appropriate technology
- Remote area
- Distance of infrastructure
- Economics of field development at current policy price

Review, Evaluation, and Recommendation

Ambiguity exists whether the above three categorizations, represented in the definition of Marginal Fields, have all to be met for each case to become eligible for the Guideline incentives. These three categories are based on:

1. Reservoir size of stranded fields
2. Compartmentalized reservoirs
3. Depleted fields requiring secondary/tertiary methods

- The current wording mentions uneconomical development but does not provide a ROI or IRR criteria to judge against or use as a reference.
- It refers to the size of the reservoir, which varies with zones (from the map in the 2012 Policy). This adds ambiguity, as being uneconomic should not be tied to the size of the reserves but to economics and a ROR/IRR criterion.
- Category 2 of the definition, which refers to compartmentalization, should not be a part of the definition as determining the economics of each compartment separately for Marginal Gas price may be inappropriate. This is because it allows companies to receive marginal price based on individual compartment development economics whereas in almost all cases these developments will happen in parallel and enjoy the economies of scale for drilling of wells and especially for surface equipment/processing facilities/transportation.
- The last paragraph of the Definitions (Section D, below) in the Consultant's opinion is too open to interpretation and gives unlimited discretion to the regulator, which may be avoided.

  "The Government may also approve a field or discovery as Marginal taking into consideration the following:

  - *Initial well Productivity*
  - *Recoverable Volume*
  - *Lack of appropriate technology*

- *Remote Area/Distance to infrastructure*
- *Economics of field development at current policy price"*

The Consultants recommend that this paragraph be deleted.

Field categorization as part of definition of Marginal Fields (Section D) should be clear that it is for any of the three listed categories. Hence it requires 'or' to be placed between category 1 and 2 and between category 2 and 3. This would then clearly introduce the three categories of Marginal Fields, namely Stranded, Compartmentalized, and Depleted Fields, which will bring clarity to all stakeholders as they approach the regulator for approval of their requests.

The Consultants recommend a revised definition for this category of fields to ensure that the parameters applicable for determination of such fields and therefore the price incentives are clear.

The recommended revised definition is provided below:

The 'Marginal Field' or 'Marginal Discovery' and 'Stranded Field' means a Gas Field that cannot be developed to produce commercially either on standalone basis or under a joint development plan with other fields, using current technologies and on the terms of the applicable concession regime.

The threshold for Fields/Discoveries to be categorized as Marginal or Stranded shall be as under:

- *The threshold for a maximum gas reservoir size (proven + probable, i.e., 2P) on geological Zone basis (Zones as marked in Petroleum 2012 Policy) is as follows:*

  Zone I - 25 Bcf
  Zone II - 20 Bcf
  Zone III - 15 Bcf
- *For Gas/Condensate Fields/discoveries, the above gas reserve threshold for reservoir size shall be applicable. However, while determining commerciality the revenues from condensate shall also be accounted for to determine whether the development of such a Field/Discovery is commercially viable without availing the incentives of these Guidelines.*
- *These Guidelines shall not be applicable to Oil Fields/Discoveries encountering or producing associated gas.*
- *In case a Field or Discovery does not fall within the above threshold for each Zone, the Government may on a case to case basis allow the incentives of these Guidelines to commercialize such Fields or Discoveries taking into consideration any or a combination of the following factors:*
  - *Low well productivity*
  - *Lack of appropriate technology for exploitation*
  - *Remote area which is not in close proximity to the main infrastructure*
  - *Applicable gas price for the field*

- *Depleted Gas Fields already nearing the end of production life requiring secondary/tertiary recovery methods to continue commercial gas production may also be considered to avail the incentives of these Guidelines on a case to case basis, keeping in view:*
    - *Remaining field reserves are within the limits of the above mentioned reserves threshold for each Zone.*
    - *Technology required and the investment to be made to commercially drain the remaining gas reserves.*
    - *Escalated unit production costs (operator using available infrastructure i.e. low volumes being processed using large equipment at tail end of producing life).*

In view of the above identified issues and challenges the Consultants recommend the following clarity mechanism to incentivise enabling production from the Stranded discovery or Depleted fields:

- Fields Size of the discovery (for Stranded fields) or the remaining reserves in case of depleted fields should not be the key criteria for providing an incentive to produce from such commercially challenged fields.
- Offering a price of $6.25/MMBTU (at a reference oil price of $110/bbl) automatically for such field identified as unable to produce commercially, is not reasonable. This is because; the applicable price for gas from such field may be between $1.5-$6.00/MMBTU (depending on PCA vintage) and the incentive offered is an immediate change to the above reference offer price ($6.25/MMBTU). This has a significantly different impact to the economics of individual fields. For example, a field that is not economical at a price of $3/MMBTU will accrue a huge windfall if it ends up attracting a $6.25/MMBTU gas price as it may be able to produce commercially at a price of say $3.65/MMBTU. For fields with applicable price of $6.00/MMBTU (i.e., 2012 Policy price) there can be an automatic move to a $6.25/MMBTU price in case the incentive is required based on economic evaluation.
- GOP should offer a price that gives a reasonable rate of return to the producer. This rate can be a fixed rate acceptable to GOP.
- The mechanics to implement the above recommendations would be that the originally applicable price for the field will need to be revised upward such that an acceptable ROR which can be 18% be generated for the project at the time of processing of such request by the regulator. The industry and regulator approved economic evaluation model should be utilized to determine this. It would be appropriate to keep the Base Price, i.e., 2012 Policy price plus $0.25/MMBTU offered in the Guidelines as the ceiling for the incentive price determined from the above calculations.

Issue 2: Applicability of Marginal Price limited to Reserves Indicated as part of Marginal Classification

Review, Evaluation, and Recommendation

The Consultants recommended that the price offered to the companies through the provisions of these guidelines should be limited to the total reserves volume used as a basis for determination for the applicability of the marginal price. If additional reserves become available subsequently (from the field, based on reservoir performance, field optimization, or application of technology) then these incremental reserves should be liable for Windfall Levy (WL) as represented in 2012 Policy. The Windfall Levy as provided for in the 2012 Policy should be applicable on the difference between marginal price being received through the application of these Guidelines and the originally applicable gas price for that EL/D&PL area.

An illustration for this is provided below:

- Marginal price is \$6.00 + \$0.25 = \$6.25/MMBTU
- Originally applicable price per PCA \$3.25/MMBTU
- Difference in price (6.25-3.25) \$3.00/MMBTU
- WL in 2012 Policy 40%

  Price for gas production beyond FDP Reserves used for Marginal Field Price incentive (3.25+3*(100-40) % \$5.05/MMBTU
- WL will be (3.00*40%) \$1.20/MMBTU*

* *per unit volume, where volume determination is post royalty adjustment*

Issue 3: Further clarity is needed for E-1.(iii)

> *"Certification that such gas cannot be produced naturally through conventional methods at commercial rates."*

Review, Evaluation, and Recommendation

The wording "naturally through conventional methods" is attracting confusion. The Certification for such fields or category should be very focused and simplified in order to properly implement the policy. The revised wording can be as follows:

> *"Certification that such gas cannot be produced commercially"*

By making such change this section will be automatically tied to the ROR/IRR suggested as a reference for determination of economics for any field under these Guidelines.

Issue 4: Remove Marginal Gas Definition in the Guidelines

Review, Evaluation and Recommendation:

There is no definition of Marginal Gas in the Policy. The Consultants consider that none is required and therefore reference to Marginal Gas in the Guideline should be removed.

Issue 5: Delivery Point needs further clarity (Section N)

> ***"N. Delivery Point and Field Gate***
> *For the purpose of pricing and delivery obligations for natural gas from Marginal discoveries, the gas will be delivered at outlet flange (Field Gate/Delivery Point). All field gate locations, for Marginal discoveries, will be anywhere within a [3] Km radius from the outlet flange of a production facility In case of sale to third parties where SSGCL/SNGPL network is not available for use, the delivery would be through a pipeline laid for the purpose or through a virtual pipeline e.g. CNG"*

Review, Evaluation and Recommendation:

The Consultants were unable to understand the logic for last sentence of the section whereby a three kilometre additional line (and therefore cost including maintenance) is being required to be put up by the producer. Since the intention of the Guideline is to provide support to Marginal, Stranded, and Depleted fields and not add additional financial burden on the producer, it is recommended to delete this section. It would be appropriate for such fields to have the flange of the facility as the "Field Gate."

Issue 6: Bring clarity to re-grant option (Section O)

> ***"O. Review of Marginal Field Guidelines***
> *DGPC may invite bids from E&P companies, to re-grant old relinquished areas with possible Marginal discoveries. The bids will be evaluated based on signature bonus, which would be spent for social welfare of the area in which the field is located. The previous licensee shall be allowed to match the highest bid."*

Review, Evaluation, and Recommendation:

The Consultants were unable to understand the logic as to why a Right of First Refusal (ROFR) was being offered to previous licensee (they may not have even bid). Offering this to the previous licensee will actually discourage other bidders to put in a good bid recognizing that the older licensee can always match their offer. The Consultants therefore recommend that the ROFR should be deleted from the Guidelines.

Issue 7: Correct base price number to be tied to the applicable price under the Guidelines (Section J)

> *"For the sale of gas from Marginal gas discovery to third parties windfall levy above the base price of US$ 8/MMBTU will be applicable to extent of 50% on the difference between the applicable base price i.e. US$ 8/MMBTU and the 3rd party sale price. All the benefits of windfall levy may be equally divided between the Federal Government and provincial Government concerned."*

Review, Evaluation, and Recommendation:

The base price represented is incorrect. It is recommended to replace the $8/MMBTU price to the applicable price under the 2012 Policy price plus an additional premium of $0.25/MMBTU as base price.

Issue 8: Section H (Retention Period) provision is too liberal

Review, Evaluation and Recommendation:

The Consultants consider that the 5-year time period being given to developing options and to implement the development plan over and above the retention period of 5 years is too long. It is recommended that these should be curtailed to 3 and 2 years, respectively. This is based on the Consultant's understanding of the objective of the Guidelines, which is to expedite the development of discoveries that are marginal, stranded or for depleted fields. The challenge is therefore economics (and not the need to have more time), which the Guidelines is addressing through price incentives and some consideration in giving reasonable time to develop these discoveries.

Issue 9: No standard provision for Policy implementation committee (Section-P).

Review, Evaluation, and Recommendation:

The Consultants recommend that following standard provision, as contained in Section V of the 2012 Policy along with appropriate modifications suggested under key issues for 2012 Policy, be incorporated as provided below:

The provision contained in 2012 Policy under Section-V "Implementation and removal of difficulties" may be added. However, as Section-V is silent about frequency of committee meetings and in case of urgent need mechanics for activation of committee, it is proposed to add a sub-clause under Section-V, which binds the committee to meet within one month of receipt of request from PPEPCA to hold a meeting to resolve an issue. It should also provide the mechanics to all stakeholders to activate the committee.

Issue 10: Oil Field size equivalence

Review, Evaluation, and Recommendation

The Consultants believe that the basis for determining oil field size using equivalent oil barrels by converting individual zone gas volumes is not relevant and should be deleted. As suggested for gas field sizes in issue #1 above, Consultants recommend deleting this paragraph and the only criteria for determination should be economics. However, application of Windfall Levy for oil may be appropriate in order to have consistency with the 2012 Policy.

5.3 LOW BTU GAS PRICING POLICY (LBGPP)

List of issues identified by the Consultants and the stakeholders as they related to the Low Btu Policy are provided in this section.

Issue1: Definition of Low Btu Gas needs to be revised

Issue2: Saleable gas to pipeline versus pipeline quality gas

Issue 3: Clarity on allocation of pipeline quality gas for LBG

Issue 4: Measurement and certification lacks clarity

Issue 5: Gas pricing clause lacks rationale

Issue1: Definition of Low BTU Gas needs to be revised

Review, Evaluation, and Recommendations

LBGPP contains the following definition for Low Btu Gas:

> "Low BTU Gas" means natural gas, which at the wellhead does not contain methane as its primary constituent and has a gross heating value of less than 450 BTU/SCF, as certified by a Certified Laboratory".

The issue with the current definition is that Low Btu Gas is not construed as natural gas. In that case OGRA will not be in a position to issue wellhead price notification. This will create a complication that will make this policy not implementable.

There are three options to address this issue:

1. Keep the definition as per LBG Policy and amend OGRA Ordinance (difficult option and out of our domain);

2. Keep the definition as per LBG Policy and create or nominate an authority to notify prices for a low btu gas (difficult to be implemented);

3. Revise the definition.

As explained above, the best option is to revise the definition. The Consultants therefore recommend changing the definition as per the revised text below:

> "Low BTU Gas" means natural gas, which at the wellhead has a gross heating value of 450 BTU/SCF or less, as certified by third party consultants."

Issue 2: Saleable gas to pipeline versus pipeline quality gas

The following amendment was made in Low Btu Gas Pricing 2012 Policy with the approval of ECC in 2013 as provided below:

- In Article 4, paragraph, titled "Gas pricing" in line 4, the word "pipeline" shall be substituted with the word "saleable".
- In Article 4, paragraph 4, titled "Gas Pricing" in the last line, the words "pipeline quality" shall be substituted with the word "saleable".

Article 4 ‘Gas Pricing ‘of LBGPP 2012 before amendment is reproduced below:

- Gas prices are always calculated on the basis of its BTU contents. The Low BTU Gas of 450 Btu/SCF has been assigned the price of US $6 per MMBTU, which shall be increased by US $0.01/MMBTU for each BTU/SCF reduction below 450 BTU/SCF up to 175 BTU/SCF for making it **Pipeline** Gas. The maximum price at 175 BTU/SCF shall be US $8.75/MMBTU. Similarly the Low BTU Gas ranging from 450 to 600 BTU/SCF would also entail price of US $ 6 per MMBTU for making it **Pipeline Quality Gas**.

The amended version of the Article 4 ‘Gas pricing ‘reads as below:

- Gas prices are always calculated on the basis of its BTU contents. The Low BTU Gas of 450 Btu/SCF has been assigned the price of US $6 per MMBTU, which shall be increased by US $0.01/MMBTU for each BTU/SCF reduction below 450 BTU/SCF up to 175 BTU/SCF for making it **Saleable** Gas. The maximum price at 175 BTU/SCF shall be US $8.75/MMBTU. Similarly the Low BTU Gas ranging from 450 to 600 MMBTU/SCF would also entail price of US $6 per MMBTU for making it **Saleable** gas.

The Consultants have reviewed both versions, i.e., version (i) prior to amendment and version (ii) post amendment version to figure out practical applicability of both options on ground. Based on the analysis the Consultants consider that individually both the versions are incomplete and insufficient and as such have challenges of implementation.

- Version (i) individually lacks a well-defined mechanism to fix a price for LBG which is not fully converted to pipeline quality, e.g., producer of LBG has processed the LBG to raise its calorific value from 350 Btu/SCF to 700 Btu/SCF. Version (i) does not address this kind of scenario and falls short to give price for processed LBG having calorific value of 700 Btu/SCF for which buyer is available.
- On the other hand, version (ii) individually lacks mechanism for LBG converted to Pipeline Quality. The term “saleable” has wider connotation. For example subject to availability of buyer, producer of LBG of 450 BTU/SCF who after processing raises its calorific value to 800BTU/SCF shall get the same *base price* as producer of LBG of 450 BTU/SCF gets without any investment on processing.

The Consultants are of the opinion that to address this issue it is appropriate to make both the gas sale options workable in Article 4 titled ‘Gas Pricing’ and Article 4 may be modified as per below:

- In case the customers are the Government or its designee gas distribution companies, i.e., SSGCL or SNGPL, the Low BTU Gas of 450 Btu/SCF has been assigned the price of US$ 6/MMBtu, which shall be increased by US $0.01/MMBTU for each BTU/SCF reduction below 450 Btu/Scf up to 175 Btu/SCF for making it Pipeline Quality Gas. The maximum price at 175 Btu/SCF shall be US $8.75/MMBtu.

- For Low Btu Gas that cannot be converted to Pipeline Quality Gas due to technical or financial constraints, the working interest owners will be free to sell it to a third party at a mutually agreed price.

To harmonize proposed amendment in "Gas Pricing Clause" with the other clauses of the Policy, we suggest that Clause "Third Party Sale" may also be amended as under:

The working interest owners after commercial discovery will make a written offer to the Government indicating the projected daily supply volumes of Pipeline Quality Gas along with all relevant information including recoverable reserves, production profiles, reservoir pressure etc. for purchase of Pipeline Quality Gas. The Government shall have the first right to purchase Low Btu Gas converted to Pipeline Quality Gas by the Producer. In case confirmation of the specified buyer is not given by the Government within 2 months, the working interest owners will be free to sell it to a third party at a mutually agreed price. For further clarity in case the working interest owners do not plan to convert LBG to Pipeline Quality Gas then they are free to sell LBG to any third party. Price should be notified by OGRA or any authority depending on the change in definition.

Issue 3: Clarity on allocation of pipeline quality gas for Low BTU Gas

Review, Evaluation, and Recommendation

The Consultants understand that there have been difficulties in implementing this provision in the past whereby producers were not able to obtain the 50% suggested volume approved by the ECC as per below representation in the Policy.

Allocation of pipeline quality for commingling with Low BTU Gas:

The Government vide policy framework approved by EEC case no: 57 /4/2007 dated 10th may 2007, may allocate pipeline quality gas for the purpose of commingling on case to case basis after giving due consideration to all relevant factors such as availability of gas in the system and infrastructure development by the producer provided the producer commits to contribute at least 50% of gas on heating value basis in commingled gas stream to be supplied to IPP.

The Consultants consider this policy provision a positive step for enabling LBG lease holders to produce and sell LBG. Therefore, the Consultants recommend that MPNR may use its own or other appropriate competent authorities to enforce the decision of ECC for LBG producers facing difficulties in the allocation of pipeline quality gas to implement a use for such resource.

Issue 4: Measurement & certification lacks clarity

> *"In order to become eligible to claim incentives given in this Policy, the producers of Low BTU Gas shall be required to obtain a certificate of the chemical composition of the gas at least from the following three of independent laboratories:-*
>
> *i) HDIP; ii) Core Lab; iii) Weatherford Lab; iv) or any other party having World Class standing and subsequently approved by the Federal Government and the Provincial Government concerned. "*

Review, Evaluation, and Recommendation

Paragraph #1 needs clarity as it asks for certification from three independent laboratories, presumably it is meant to get certification from any one of the three. Consultants recommend appropriate wording change to reflect this.

The Consultants recommend the need to revisit names of laboratories proposed to check credibility for the Weatherford Lab. Also need to represent the location of the other laboratories in Pakistan.

The Consultants recommend that Policy may be specific about sampling (composite) given the experience of finding different compositions from different individual wells within same field as gas composition can vary between different parts of the reservoir or field (e.g., Uch field has varying gas composition in different parts of the reservoir and composite sampling is important). The samples provided to the laboratory for BTU/composition evaluation should be representative as this information will be used for requesting the gas price from the regulator. The Policy however does address the need for online determination of gas quality supplied to buyer through use of a chromatograph once gas is on production.

It is also important to crystallize the recommendations on how the determination of LBG is done as the producers may possibly exploit the well rates to maintain Btu lower than 450 to attract the benefit of this incentive during early period of production. The Consultants therefore recommend that necessary changes are made in the definition of the LBG such that this possibility of additional price thru manipulation is eliminated. An option to consider would be of producing all wells drilled in a LBG reservoir proportional to their deliverability to ensure that the likelihood of manipulation of the composite gas stream sold is minimized. This requirement can be managed through third-party certification of the production profile in the FDP such that it includes the rationale/basis for proposed production mix from wells.

An important point to make in this particular situation is that if the initial BTU determination, prior execution of the FDP, is below 450 BTU but goes up once the composite BTU becomes available and is above 450 will the field still fall in the LBG Policy? Consultant recommends that once the field is classified as LBG field then this classification should stay for 5 years at which an updated FDP may be required for re-classification.

Issue 5: Gas pricing clause lacks rationale

> *Gas prices are always calculated on the basis of its BTU contents. The Low BTU Gas of 450 BTU/SCF has been assigned the price of US $6 per MMBTU, which shall be increased by US $0.01/MMBTU for each BTU/SCF reduction below 450BTU/SCF up to 175BTU/SCF for making it pipeline Gas. The maximum price at 175 BTU/SCF shall be US $ 8.75/MMBTU. Similarly the Low BTU Gas ranging from 450 to 600 MMBTU/SCF would also entail price of US $6 per MMBTU for making it pipeline quality gas.*

Review, Evaluation, and Recommendation

The Gas Pricing Clause includes provision for LBG price applicability for gas in the range of 450 to 600 BTU/SCF. Having more than 450 Btu/Scf as per definition is not low BTU gas and is therefore not entitled for low BTU price regime. However, if the intent of the policy makers is to also offer $6/MMBTU for such gas then that will be inherently unfair to discoverers of gas with BTU value between 601 and 900 BTU and can be challenged by them.

The Consultants recommend that provision for LBG price applicability for 450-600 Btu/Scf gas is deleted as it is not part of the definition of Low Btu gas.

5.4 TIGHT GAS POLICY:

A list of issues identified by the Consultants and the stakeholders as they related to the Tight Gas Policy is provided in this section.

Issue 1: Definitions of Tight Gas, Tight Gas Reservoirs and Tight Gas Reserves do not have the required clarity for implementation

Issue 2: Management of mixed production from a single well (Article 8 needs to be revisited)

Issue 3: Clarity on ownership of facilities when both conventional gas and Tight Gas is being produced through common facilities but owned by one Lease holder

Issue 4: Suspension of production needs clarity (Article 17)

Issue 5: Provincial governments have been given the role of regulation

Issue 6: Implementation of Tight Gas Policy

Issue 7: List of consultants given in the Article 6 needs to be revisited.

Issue 8: PPEPCA Concerns: Sale of Gas to 3rd Parties

Issue 1: Definitions of Tight Gas, Tight Gas Reservoirs and Tight Gas Reserves do not have the required clarity for implementation

The definition of Tight Gas in the Policy (Article 4) is as provided below:

The Tight Gas is defined as a natural gas that:

i. *The company demonstrates to the satisfaction of the Federal Government and Provincial Government concerned that it cannot flow naturally at commercial rates with conventional methods despite of having hydrocarbon reserves; and*

ii. *Requires advanced technologies for its exploitation/production such as high performance perforation, hydraulic fracturing, horizontal wells, multilateral wells &/or infill drilling or combination of these technologies or any new technology acceptable to the regulator; and*

iii. *Has estimated value of effective permeability less than "1.0 milli Darcy (mD)" as determined pursuant to clause-5 of this policy.*

Reservoir hosting Tight Gas in-situ is defined as "Tight Gas Reservoir" and gas reserve trapped therein is defined as "Tight Gas Reserve".

Wells having effective permeability of more than "1.0 mD" shall be classified as conventional wells.

Review, Evaluation, and Recommendation

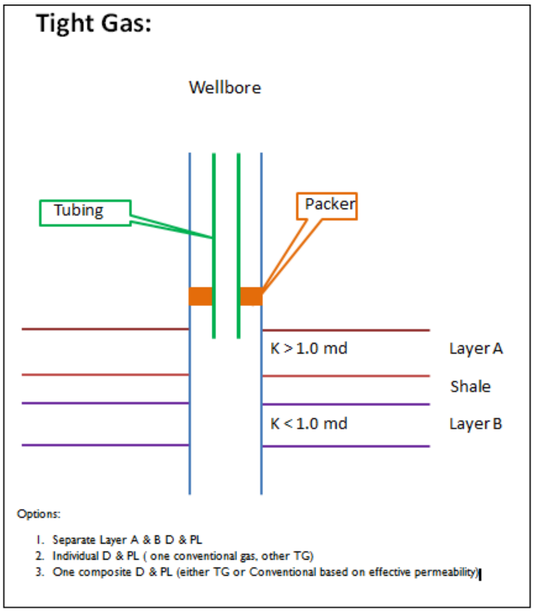
Definitions of Tight Gas, Tight Gas Reservoirs, and Tight Gas Reserves contained in Article 4 of the Tight Gas Policy are not clear and comprehensive. Clarity is needed to determine that in case of more than one Tight Gas formation or isolated intervals encountered through one well, whether effective permeability would be calculated on individual formation basis or on the basis of the total pay interval. It is recommended that the basis used for determination of net pay and hence permeability should be restricted to those zones that are expected to contribute to or have potential to contribute in gas flow, i.e., the net pay identified for the formation under test. Also the determination should use the well test permeability as the reference data for determination of whether a discovery area can be classified as Tight Gas Reservoir or not. Permeability from logs or core analyses should only be used to further substantiate the assertion of the reservoir being a Tight Gas reservoir. This of course puts further challenge on both the industry as well as the regulator for landing at a mutually acceptable net pay that will then determine the effective permeability of the zone or formation that is being represented as producing Tight Gas. The Consultants believe this to be another justification for bringing in a reputable reservoir Consultant to help provide the definition for Tight Gas by understanding all the different scenarios affecting this determination and hence proposing a definition that can appropriately address the many challenges inherent in the definition.

Clarity is also needed concerning third-party certification about production of Tight Gas at commercial rate through conventional methods. Commercial rate is an undefined and open term and there is a need to specify gas price applicable to the EL/D&PL to be used for working out commerciality.

Definitions are the foundation stones for establishing eligibility of lease holder for incentives provided in the Policy. Therefore, Consultants recommend that definitions contained in Article 4 may be revisited and thoroughly reviewed, by a subject specialist (by engaging a reputable reservoir consultant), for issues identified above and specifically for value of effective permeability put as a condition in sub Para-iii of Article 4 of the Tight Gas Policy.

Figure 5 below identifies the challenge for crystallizing a definition for Tight Gas. There may be more than one layer, formation, or reservoir in a well, each having a different permeability. It is important to clarify whether determination of Tight Gas will be for each such layer as typically when a well is perforated more than one layer or reservoir may be perforated at the same time to get economic higher production and the well tests will therefore determine an effective permeability for the well. This effective permeability is for the well and not the individual layer or reservoir.

Figure 5. Options for definition of Tight Gas



Thus in a well with two layers or reservoirs (with permeabilities of say, 0.8 mD and 1.1 mD) a company will be able to designate one of the reservoirs as Tight Gas Reservoir and claim a higher price while the overall production from the well may be much more than what is economic for production. The justification of a higher price for a Tight Gas Reservoir is economics of producing the well or reservoir. In the above example, the regulator will end up giving the Tight Gas price for an otherwise very economic well. Hence a clear definition of Tight Gas needs to be developed that addresses issues like this and others to ensure the necessary price support for a well or reservoir, where needed, and not a blanket one as it currently stands.

The applicability of Tight Gas D&PL also seems difficult to implement. The reason being that distribution of permeability in any given area may vary significantly due to natural variation in facies and fracture distribution. Well test can only prove permeability for one well only. The subsequent wells may exhibit higher, equal, and lower permeability. Therefore, it would be logical to decide the Tight Gas on a well-to-well basis where the size of the D&PL area is based on the drainage area of the Tight Gas well as determined through well tests and certified by a reputable reservoir Consultant.

Issue 2: Management of mixed production from a single well (Article 8 of Tight Gas Policy) needs to be revisited

Review, Evaluation, and Recommendation

The language of Article 8, *"Management of mixed production from single well"* is not clear or comprehensive. The following two consecutive sentences convey contradictory messages:

> *"If a tight gas and/or conventional gas are produced from the same well or from the different zones of the D&P lease, the allocation of the tight and conventional gas*

shall be done on the basis of flow rates supported with third party determination. No commingled production shall be allowed from the same well unless produced through dual completions or other internationally acceptable method as approved by the Regulator."

The Consultants recommend correcting the language to ensure that a clear message is conveyed to the stakeholders as to how this situation will be managed as represented below:

"If a tight gas and/or conventional gas are produced from the same well or from the different zones of the D&P lease, the allocation of the tight and conventional gas shall be done on the basis of flow rates supported with third party determination.

Commingled production shall also be allowed from the same well if produced through dual completions or other internationally acceptable method as approved by the Regulator."

The above is a simplistic model assuming only one productive layer of Tight Gas or conventional gas in a particular formation. In actual cases there may be isolated layers with variable permeability within the same formation. In this case, it would not be possible to isolate the conventional and Tight Gas reservoir production, which further adds to the difficulty for the regulator to accept a request for Tight Gas classification for an individual well.

Furthermore Article 8 binds the operator to put in place a mechanism for observation of the wellhead gas flow rates by the representative(s) of the regulator. This is an unnecessary burden on lease holders as Article 8 already provides for appropriate allocation mechanism for the situation of combined production of Tight Gas and conventional gas.

Issue 3: Clarity on ownership of facilities when both conventional gas and Tight Gas are being produced through common facilities but owned by one lease holder

Review, Evaluation, and Recommendation

For optimal development of Tight Gas reservoirs, there is likelihood that some of the Tight Gas will be processed through gas processing facilities owned by lease holders of conventional gas and Tight Gas. Under the Rules, after expiry of the concerned conventional gas leases, the Government can take over such facilities. This can cause problems for Tight Gas lease holders using those facilities besides impacting production.

This issue can therefore cause significant complications and needs to be addressed. The Consultants recommend making provision in the Tight Gas Policy that common facilities being used for conventional gas and Tight Gas would not be taken over by the Government till expiry of both conventional and Tight Gas leases and rules may be modified accordingly.

Issue 4: Suspension of production needs clarity

> *"Article17. Suspension of production for a cumulative period of one year will be allowed to working interest owners subject to technical and economic justifications. A company shall deem to have suspended the production in a month if the production is suspended for more than 15 days on account of reasons other than (i) force majeure and (ii) planned plant shut down for maintenance in accordance with the provision of the Gas Sales Agreements. After expiry of the said period, Federal Government and the Provincial Government concerned may grant further extension on case to case basis subject to justification acceptable to the Regulator."*

Consultants consider this aspect needs to be addressed in the Policy.

Review, Evaluation, and Recommendation

Article 17 of the Tight Gas Policy addresses the issue of suspension of production. This Article is not clear on aspects such as the cumulative period of one year allowed. Clarity is missing regarding following:

- Whether permission for the cumulative period of one year is for the life of the field, and
- Whether the deemed suspension of one month if the production is suspended for more than 15 days expires at the said period.

To remove the confusion, Consultants recommend using standard provision contained in the 2013 Rules for production continuity, which is fairly comprehensive, well understood by stakeholders, and operationally more flexible.

Issue 5: Provincial governments have been given the role of regulation

Review, Evaluation, and Recommendations

Subsequent to 18th Amendment of the Constitution of Pakistan, different opinions were expressed about the role of Provincial governments in the regulation of petroleum exploration and production activities. However, no final verdict has yet come out and the reality is that currently only the Federal government is performing the role of regulator and Provincial governments have no such role. The Consultants recommend that until any final verdict is available, the Tight Gas Policy document should only refer to the regulator instead of referencing to "Federal" and "Provincial" governments and these may be replaced by the term "regulator."

Issue 6: Implementation of Tight Gas Policy

Review, Evaluation, and Recommendation

The Tight Gas Policy provides a mechanism to oversee the implementation of the Policy that is different from what is provided in other Policies. The other Policies provide a high level forum for implementation of Policy and removal of difficulties.

The Consultants recommend having a similar forum for Tight Gas Policy and modifying this Article accordingly.

The Consultants recommend that following standard provision as contained in Section V of the 2012 Policy along with appropriate modifications suggested under key issues for 2012 Policy be incorporated in the Tight Gas Policy. However, as Section-V is silent about frequency of committee meetings and in case of urgent need mechanics for activation of committee, it is proposed to add a sub-clause under Section-V that binds the committee to meet within one month of receipt of request from PPEPCA to hold a meeting to resolve an issue. It should also provide the mechanics to all stakeholders to activate the committee.

Issue 7: List of consultants given in the Article 6 needs to be revisited

Review, Evaluation, and Recommendation

The list of companies contained in the Article 6 of the Tight Gas Policy for certification of Tight Gas, nature of reservoirs, gas reserves and allocation of Tight Gas to total production in case it is produced from conventional reservoir/field, include a couple of names that need to be reviewed.

The Consultants recommend that only internationally recognized renowned companies are included in the list as certification from third party consultants is one of the key elements for achieving objectives and successful implementation of the Tight Gas policy.

Issue 8: PPEPCA Concerns: Sale of gas to third parties

According to PPEPCA, currently there is conflict between the Rules, provision of PCAs, and Tight Gas Policy with regard to sale of gas to third parties.

Consultants consider this aspect needs to be addressed in the Policy.

> *10.2. The working interest owners shall have the right to sell the gas to third parties within Pakistan at mutually negotiated prices between the Seller and the Buyer.*

Review, Evaluation, and Recommendation

Article 10 of Tight Gas Policy "Gas Pricing" covers sale to third parties. It is unusual to cover provision for third party sale under the Article for pricing. The Consultants recommend that provision for sale of gas to third parties be made in the Tight Gas Policy as an independent Article. The Consultants also recommend that the Article for sale of gas to third parties be modified to align it with the provisions for third party sales contained in the Rules and PCAs.

5.5 RECOMMENDATIONS FOR IMPLEMENTATION COMMITTEE

Issue 1: Challenge of Implementation of Policy by the Regulator

Issue 2: Clarity on Foreign Exchange (Article 7 of 2012 Policy)

Issue 3: No tie between Indexed Rent Payment and License or Lease Extensions

Issue 4: Is financial impact of new policy determined at MPNR?

Issue 5: Consider Creating DGPC as an independent Regulator

Issue 1: Challenge of Implementation of Policy by the Regulator

Many companies were of the point of view that main challenge is with the implementation of Policy by the regulator. It is felt that there is a lack of clarity and comprehension of the 2012 Policy provisions at the regulator's end (e.g., Conversion to 2012, incentive price for incremental production, definitions for Marginal Fields and Low Btu/Tight gas). Some of the companies also suggested that regulator needs to impress upon its officials that instead of looking at requests of companies with mistrust, they should endeavour to facilitate the E&P companies in carrying out E&P activities.

Review, Evaluation, and Recommendation

The point brought up by the companies is based on different interpretations of policy provisions by the regulator and companies. In the Consultant's opinion, this gap could have been prevented by holding joint sessions/seminars for the regulator and companies to discuss the provisions of final draft of 2012 Policy. Although late, it would still be useful if such sessions/seminars are held to align regulator and companies with regard to understanding of Policy provisions based on the recommendations in this report. It is also pointed out that the 2012 Policy contains a provision under Section-V "Implementation and removal of difficulties" under which a high level committee has been constituted to address the issues of implementation of 2012 Policy and removal of difficulties and anomalies. In the Consultant's opinion, 2012 Policy contains an appropriate forum for resolving policy implementation issues but Section-V is silent regarding the frequency of committee meetings and in case of urgent need the mechanics for activation of this committee. The Consultants recommend adding a sub-clause under Section-V that binds the committee to meet within one month of receipt of request from PPEPCA to hold a meeting to resolve an issue. It should also provide the mechanism to all stakeholders to activate the committee for any urgent issue.

Issue 2: Clarity on Foreign Exchange (Article 7 of 2012 Policy)

A number of foreign companies identified that contrary to terms of their relevant PCAs, the State Bank is refusing to allow companies to retain export sales receipts in foreign currency outside the country. They pointed out that this is contrary to the provisions of their PCAs. They also mentioned that there have been several occasions in the past of being able to do so under the same PCAs without any issue raised by the State Bank.

Review, Evaluation, and Recommendation

Foreign E&P companies need the ability to remit their revenues abroad without any restrictions (as represented in the PCAs). If they are able to remit payments made for sales within the country, as per the following provisions of the PCA, they should be equally able to do the same for export volumes.

> *"7.2: Subject to domestic supply obligations and export duties, each foreign E&P Companies shall be entitled to export its share of the petroleum acquired under an agreement, in accordance with the applicable laws. Each foreign Contractor/Operator (and its registered branch in Pakistan) shall have the right to retain abroad and to freely make use of sale proceeds from the export of its share of petroleum.*
>
> *7.3: Foreign E&P companies shall have the right to remit sale proceeds from the sale of petroleum within Pakistan in foreign currency abroad in accordance with applicable regulations of the State Bank of Pakistan. GoP shall ensure that the State Bank of Pakistan shall permit all remittances of funds without any delay or additional cost to such companies."*

While Article 7.2 is explicit in allowing Foreign E&P companies to retain abroad and to freely make use of sale proceeds from the export of its share of petroleum, Article 7.3 needs to be clearer. This is because it ties the ability of the foreign E&P companies to remit proceeds from sales (both within and outside the country) to the applicable regulations of the State Bank. Clarification is needed so that remittance is allowed subject to appropriate procedural requirements at the State Bank that should not take away their right to remit such funds overseas. The companies should be given the right to remit and this should not be dependent on the then or subsequently applicable policies/regulations of the State Bank, which may restrict such remittances in the future (i.e., ensure stability of the contract vis-à-vis foreign currency payments).

The Consultants recommend that Article 7.3 be modified accordingly to address the issue.

Issue 3: No tie between Indexed Rent Payment and Licence or Lease Extensions

It is necessary to process extension cases without any linkage between indexed rent payment and license or lease extensions.

Review, Evaluation, and Recommendation

According to some companies, the regulator is linking approval for extension of ELs/D&PLs with payment of indexed rent. Most of the companies are agreeable with payment of indexed rent provided indexation is applied from the date of grant of EL instead of applying this from the date of issue of the rules applicable to the particular lease, which (in most cases are even higher than what has been prescribed as rent in the subsequent petroleum policies).

This comment was somewhat surprising and if it is accurate, then the Consultants recommend that any such linkage should be avoided and DGPC may revisit the basis being used for indexation of rent from the issue date of the applicable rules. Consultants understand that PPEPCA has already submitted a draft letter for the Law Division. It is suggested that the regulator may resolve this issue as per the suggestions of the industry.

Issue 4: Is financial impact of new policy determined by MPNR?

It does not appear that there is sufficient on-going effort within MPNR to understand and work out the financial impact of new proposals (policy or other incentives).

Review, Evaluation, and Recommendation

Consultants believe that for giving financial incentives under any petroleum policy, a detailed analysis should be carried to determine the need, quantum, and impact of such incentives for the Government and the other stakeholders. The Consultants were not able to locate any documentary reference containing the basis used for incentives provided under 2012 Policy (or for other recent policies, e.g., Tight Gas, etc.). There is a need to use the Policy Cell to evaluate this on a regular basis and determine the quantum and impact of 2012 Policy incentives including:

a. Increase in petroleum exploration and production activities
b. Addition of reserves/resources from such activities
c. Increase in oil and gas production rates
d. Increase in investment in the upstream petroleum sector

Furthermore, Policy Cell may also obtain feedback and suggestions from all stakeholders and gather information about incentives provided in petroleum policies in peer countries to determine Pakistan's competitiveness. It may also analyse oil and gas price structure based on replacement cost. This exercise would help identify the need for modifications to the Policy and timing for the same.

Over the past few years the Policy cell has hardly existed or been active. The key challenge appears to be funding for professional staff given that attracting good experienced staff for this effort is significantly hampered due to lower than market offers and provision of needed hardware and software for their work. The Consultants recommend GOP address this issue.

Issue 5: Consider creating DGPC as an independent regulator

Review, Evaluation, and Recommendation

Most of the companies showed concerns that as part of mainstream Government structure the regulator has certain limitations such as:

- Limited decision-making authority;
- Longer chain for regulatory approvals;
- Low salary structure and hence staff retention challenge;
- Rigid and time consuming rules for recruitment; and
- Longer and time-consuming processes for office facility upgrades.

The Consultants support the idea of making DGPC an independent and autonomous organisation with its own budget and Authority to facilitate decision making. This would ensure that they are able to pay market-based salaries to their professionals and hence would help DGPC to retain and attract professionals with rich experience, more authority for decision making at their level (without requiring approvals through the long chain of command), and more flexibility to upgrade its office facilities (e.g., information technology network and data storage).

6. REGULATORY IMPEDIMENTS AND RECOMMENDATIONS

Based on input from stakeholders and the Consultants' review, the following regulatory impediments related to the Policies that have slowed down the pace of exploration and production activities in Pakistan were identified. The Consultant's recommendations for addressing these are also provided.

- Lack of clarity around certain provisions of the policies:

  Over 60 issues have been identified and recommendations made that provide further clarity in the Policy documents and address issues in the individual Policies for clarity and completeness. Some examples from the 2012 Policy include the bidding process, transfer of work commitment, the review of zones for pricing/work commitments, relinquishment of areas, and logic for EWT and incentives for incremental production. A number of cases are pending with the regulator due to the lack of clarity around the 10% incremental production incentive in the Policy document, and the companies have expressed frustration with the delays in approval of their requests. On the other hand, the regulator does not have a clear enough document that addresses the various situations being presented by the companies, as specific to them, and is hence unable to move these requests forward. Similarly, the report identifies a significant challenge regarding definitions and eligibility criteria for Tight Gas, Low BTU Gas, and Marginal/Stranded Gas in the respective documents and makes appropriate recommendations.

- Lack of completeness of the Policy document:

  Lack of completeness of Policies poses serious challenges, e.g., the 2012 Policy lacks a Model Supplemental Agreement (MSA) for conversion. This lack resulted in inordinate delay in finalizing MSA and hence delays for E&P companies that opted for conversion. The Consultants recommend that Policies should be complete and self-contained, e.g., the MSA, which is a pre-requisite for conversion, should have been part of the Policy. The Consultants recommend that in future the policy document should be complete in all respects.

- Lack of legal base and regulatory regime for implementing Tight Gas Policy, Low Btu Policy, and Marginal Gas Fields Guidelines:

  Currently Tight Gas Policy, Low Btu Policy, and Marginal Gas Fields Guidelines lack a legal base and regulatory regime for implementation. This causes further challenges in terms of applicability, where, for example, Tight Gas Policy provisions are discovered in an area where the PCA was signed prior to the 2012 Policy and earlier rules apply that have no provision for addressing the specific issues related to a Tight Gas discovery like retention or lease period for a D&PL.

- Lack of a well-defined program to provide all stakeholders with information that would facilitate a similar understanding of policies, their intent, and their interpretation:

  The Consultants are of the opinion that final drafts of Policies should have been discussed in joint sessions of all stakeholders to develop understanding of policies provisions and bring all stakeholders to a similar understanding. This would have accelerated the regulatory process and hence exploration and production activities. The Consultants recommend that meetings and joint sessions with all the stakeholders, including the regulator's team and the E&P companies, participating should be held.

- Lack of consolidation of various policies under a single document:

  The Consultants are of the opinion that it would have been preferable had the Policies been prepared as a single document with a single vision that was drafted after due consideration rather than the current piecemeal policies. Furthermore, there should have been greater analysis as to how to permit existing concessionaires to avail the new policies. It may be appropriate here to consider combining the Tight Gas Policy with the under preparation Shale Gas Policy, as a single document since both Tight Gas and Shale Gas are classified as un-conventional gases.

- Conversion only available for 90 days is now an impediment:

  Under the 2012 Policy, the conversion option was available for only 90 days from the notification of the 2012 Policy. As stakeholders have identified various challenges in interpretation and clarity around intent it has kept them from choosing to convert to avail the incentives provided by the 2012 Policy. The Consultants recommend extending this conversion option until through 2015 to provide an opportunity for E&P companies to select conversion to the 2012 Policy if so desired.

- Need to activate Committee for policy implementation:

  The 2012 Policy contains a provision under Section-V "Implementation and removal of difficulties" under which a high level committee has been constituted to address the issues of implementation of the 2012 Policy and removal of difficulties and anomalies. In the Consultant's opinion, this is an appropriate forum for resolving policy implementation issues, but Section-V is silent about frequency of committee meetings and in case of urgent need the mechanism for activation of committee. It is proposed to add a sub-clause under Section-V that binds the committee to meet within one month of receipt of request from PPEPCA to hold a meeting to resolve an issue. In case of an urgent issue, it should provide a mechanism to enable stakeholders to activate the Committee.

- Confusion post 18th Constitutional Amendment:

  Subsequent to 18th Constitutional Amendment significant confusion has arisen about regulation of the petroleum upstream sector. This confusion resulted in certain provisions in the policies; e.g., the Tight Gas Policy provided an equal role to provincial governments for regulation of E&P sector, whereas the 2012 Policy contains a provision about reorganization of DGPC that includes provincial representatives. This confusion resulted in slowing down the pace of E&P activities. The Consultants recommend bring clarity to the issue of the role of Provincial governments in regulation of E&P sector as soon as possible to remove any ambiguity regarding the regulatory authority for E&P activities.

- Update Policies on a regular basis:

  The Consultants are of the opinion that prevailing policies may be updated rather than issue new policies. This wold eliminate the challenges to both the regulator and the E&P companies in developing understanding and alignment with the new policies.

- Capacity and Implementation:

  The limited capacity significantly hampers the regulator's ability to implement Policies, especially policies through the 2013 and earlier Rules. The regulator's challenge in this regard is due to various constraints, such as lack of technical experience and unfilled positions in the DGPC's office due to the hiring freeze. The consequence for stakeholders is that resolution on their issues, including those tied to the implementation of recent Policies, has been delayed. Their suggestions were for an organizational overhaul in DGPC that takes in to account the increased work flow through the regulator's office due to the significant rise in the number of ELs and D&PLs; they also recommended development and implementation of Standard Operating Procedures (SOPs) for many of the routine and regular matters managed by the regulator.

The Consultants recommend development of a capacity building plan for the regulator's office as well as review of existing SOPs and development of new SOPs to serve today's needs.

ANNEXURE - I

This Annexure captures the areas included in conversations with stakeholders, as appropriate.

Exploration Activities

- Grant reconnaissance permits
- Grant exploration licenses (EL)
- Review work programs / work units
- Requests for exploration license extensions/renewals
- Relinquishment of acreage (mandatory & total)
- Requests for well commencement, testing, and side-tracks
- Requests for plug & abandonment
- Declaration of commerciality
- Requests for extended well testing
- Approval of Petroleum Concession Agreement, Petroleum Sharing Agreement, Supplemental Agreements, Assignments, etc.
- Review of periodic reports submitted by the E&P Companies
- Division of Area into block and zone
- Appraisal, evaluation and renewals
- Retention of gas discovery
- Reports of discovery
- Petroleum exploration within lease area
- Exploration and use of facilities by third party
- Programs related to unconventional hydrocarbon resources

Production Activities

- Regulate petroleum development & production operations
- Development & production lease application (D&PL)
- Review of development plans
- Requests for well commencements, testing, side-tracks, plug & abandonment
- Requests for well testing & in-fill wells
- Requests for D&PL renewal/extensions
- Flaring consent
- Award/application of gas pricing regimes
- Review of unitization cases & disputes
- Relinquishments of acreage
- Review of periodic reports submitted by the E&P Companies
- Re-grant of lease after expiry of lease term
- Transportation of petroleum
- Revocation of lease
- Inspect plants, production records and well records
- Commencement, testing and abandonment of drilling operations

Support Services & General Activities

- Interpretation of PCA's provisions/rules
- Policy formulation
- Provincial Government Issues
- Force majeure issues
- Facilitation including imports & exports
- Audits both technical & financial
- Rents & marine research fees
- Fulfilment of training obligations
- Payment of royalty & taxes
- Fulfilment of social welfare obligations
- Payment of production bonuses
- Data collection/management
- Litigation & arbitration cases
- Periodic reports including daily, monthly, and annual reports.

ANNEXURE -2

NOTES FROM MEETINGS WITH STAKEHOLDERS

This Annexure captures the interaction by Consultants with the individual stakeholders during September 2014.

COMPANY A:

- Incentives relate to gas sector only – we have oil. Problem arose from 1997 Policy – if we convert in order to secure gas incentives we lose benefit on liquids – because this works as a package we have not converted.
- Why will GOP not offer price increase to match other producers?
- Implementation of "additional 10%" added to 2012 Policy by amendment– how will these works in practice?
- 18th Amendment – we consider the argument between Provincial and Federal to be fixed now.
- Commercial discovery – delays in obtaining GOP approval. Need approval to be retrospective to cover EWT production; *but is the benefit of higher price outweighed by subjecting EWT production to royalty?*
- Quality of operator submissions has raised GOP expectations of what will be included in FDPs.
- Regulator has been allowing extensions in periods to avoid claims of force majeure but this is entirely discretionary.
- Relinquishment – we prefer allocation of smaller acreage and a lower requirement to relinquish.
    - Option to not relinquish against additional work program, e.g., 30% additional work units for 30% area relinquish.
- Third-party access rules are intended only for gas.
- DGPC is not providing a buffer between IOCs and state companies.
- Definition of "local" is unclear – by contrast "from this area" is clear – does "local" mean Pakistan national?
- Extension of lease after expiry – we are concerned about the additional 15% payment – but this is probably OK provided it can also apply to pre-2012 contracts (i.e. we can extend them on the same basis).
    - Rule 34 , may vs. shall for extensions/renewals
- Marginal fields – definition in guidelines is confusing because it refers to both economic considerations and production forecast – latter seems too broad brush.
- BTU policy is not achieving its intention – what is the rationale for the pricing structure?
- Withdrawal after bidding – there is no penalty if the highest bidder withdraws. How can companies be incentivised to commit? What happens next – does GOP deal with second highest or offer acreage for re-tender?

COMPANY B:

2012 Policy

- Incentives may be out-dated by the time it comes out due to long gestation period. Revision, not new policy is suggested for the future required.
- Appears GOP has no will to implement policy this time
- Fields X and Y. Issues on production vs. sale. Suggestions for new FDP
- Cos Begging to get 2012 Policy price for new discoveries
- Supplemental for conversion still awaited
- Risk is that if it is difficult to get incentives it will jeopardize future investment by foreign companies
- Indexation issue: tying rent indexation to renewals/ extension is not ok
- Everything goes to the top for approval
- Approvals should have categories i.e., info only, deemed approval and approval
- Chairing of OCMs by regulator should be eliminated
- Relinquishment?
- Unable to farm-in with others who are sitting on blocks for many years w/o executing committed work program
- Appellate
  - Regulator capacity needs to be enhanced
  - Whatever regulator is happy to agree but wants Secretary to decide.
- Circular debt is becoming a big issue again
  - 30% FE payment- Money is stuck with transmission company

Tight Gas Policy

- Price is not attractive any more

Marginal Field Guidelines

- Maturing fields need to be covered
- Policy includes Mining Lease but Low Btu does not
- Declining fields becoming uneconomic

Other

- Limit / clarity on Gas Infrastructure Development Surcharge and Transmission Tariff clarity is needed
- Data Purchase
- Data reporting: Can the previous website by LMKR be worked so daily requests go away?
- CSR: Old system when company disbursing/spending funds was Ok
- Provincial regulator: Support PPEPCA view- i.e. one regulator
- Double hatting by Regulator
- Wish list on data/well notification, need clarity on what is really required
  - Examples of duplication

- PPEPCA input is now reduced
- Work Unit is Seismic focus
    - Need to improve balance with possibly other G & G work.

COMPANY C:

- DGPC is weak in decision making and has problems in
    - capacity
    - comprehension
    - prioritisation
    - demarcation
- The problem is implementation of policies rather than interpretation.
- Example – we await approval of a declaration of commerciality and meanwhile production continues as EWT and we suffer a discount on the older price. Other companies suffer similarly.
- On a recent discovery we will not proceed without a firm commitment to price. OGRA will not fix a price until a supplemental agreement is signed for the conversion to current rules. Can a price be notified provisionally pending execution of a supplemental agreement?
- FDP approval – there is no period stated within which DGPC must respond.
- Example – DGPC refuses to approve an FDP because it is based on economics, which assume a price which will not be fixed until a Supplemental Agreement is signed.
- Bring clarity around what is needed for FDP/DoC Approvals. Create checklist that everybody works with i.e. DGPC/Operator
- Two burning issues for us are incremental production and lease extension.
- First extension after 25 years should be at producer's option subject to commercial production continuing. Should have same for extension after 30 years (subject to increased payment). This is justified by the need to make earlier investment decisions based on the assumption that extension is optional – not discretionary.
- No need to amend force majeure provisions – GOP should not have right to terminate after a fixed period of FM.
- 2012 Policy amendment for incremental production needs further improvement.
- The hurdle is an increase of 10% over a historic level but the price incentive is then given for the whole of the increase and not simply the margin over 10%.
- Fields at this stage are likely to be in decline so it is unfair to ask that this increased level be maintained. We argue that the producer requires to show a 10% increase above the forward production forecast because the purpose of the incentive is to encourage acceleration of production
- Tight Gas Policy – see proposal from PEPPCA.
- A rule under Section 5 of the 1948 Act would provide a legal basis for a Supplemental Agreement to enable a lease for 40 years rather than the usual limit of 25+.

- Provincial involvement – the fact that the CCI approved the 2013 Rules implies that the Provinces have delegated management and control of oil and gas to the FG. CCI approved the 2013 Rules without reference to TGP (which refers to PG approval along with FG).
- Communication of reserves between two fields – DGPC has clear role under [2013] Rules. 1986 Rules apply to one field whereas 2001 Rules to other.
- Disparity in treatment of different companies with respect to extensions – some companies are given extensions to do nothing!
- Income Tax – prior to a 2012 amendment sale price for oil and gas sales were exempt from withholding tax but now foreign companies are treated differently which is discriminatory (Schedule 2 Clause 46?).
- Contrary to terms of the relevant PCA, Pakistan State Bank is refusing to keep export sales receipts in foreign currency.

COMPANY D:

- Challenge for DGPC is achieving the right level at which to manage the industry. It needs to spend more time on ensuring effective management of the national reserve base than micro managing producers' activities. For this purpose it needs a consistent and annually updated view of the reserve base.
- Regulation and policy should not be confined in one agency – regulation is not a commercial issue.
- GHPL has lost its sense of impartiality – with a board full of GoP people it behaves like an arm of FG.
- "Endless analysis is leading to paralysis".
- Regulator is not geared up to respond to the increased pace of the industry – it ought to be geared up because this activity is in the national interest.
- "Indexation and extensions" – it is necessary to process cases without any linkage between these two issues.
- For a discovery, which is likely to overlap with a state owned company lease, DGPC has refused to approve a second well. Proposal of unitisation not taken positive as DGPC will not approve DOC or FDP.
- The 10% enhancement for incremental gas production should be based on proven reserves and be linked to new investment. PPEPCA paper under review
- 2012 Policy however provides a disincentive to explore those areas where the oil/gas split is uncertain and this is stalling gas exploration in some areas.
- We propose that conversion should be possible on an individual field or lease basis rather than as a package.
- 1994 Policy imposed heavy social obligations and these are now occupying too much management time. We propose that producers make a lump sum payment to FG, which assumes all obligations and may delegate these to PGs.
- Option to pay obligations as per the PCA w/o any implementation, extra work at the discretion of the JV

- The industry is hurting and DGPC does not appreciate the impact of delay on a pro-active industry. It has insufficient technical competence.
- Industry is willing to pay for a quality service which achieves some independence of thought. State companies are exerting undue influence on DGPC whose mind set is to protect state interests to the exclusion of private interests. We need a one-stop shop on regulation which is effective and we need clarity where there are overlapping roles
- Joint ownership as established by the 18th Amendment is being used by different provinces in different ways.
- The "local" definition creates problems for us – local authorities become antagonists to E&P companies making unreasonable demands outside their scope of authority.
- There can however be some benefit where a local authority takes ownership of an area of responsibility
- We have no issue with land rentals but the inflation linkage of old rules rentals make them less attractive than the rentals under 2013 Rules.
- Extensions beyond 25 years should be at the producer's option – in other words a producer should have the right to continue indefinitely while there is commercial production (but we would concede an increased government take at some point).
- On relinquishment the incumbent licence holder should always have the advantage because it knows the field so we favour minimal relinquishment and retention of data for a short time at least.
- Data should generally be kept confidential but we need clarity as to what must be included – across the range from raw data to company's internal interpretations. Need to define what is needed by DGPC and for what purpose.
- The charge by DGPC for data should be based on actual cost and allow no profit margin.

COMPANY E:

- Generally facing the same problems as another company.
- Provisional approval to allow early production- in house certification should be sufficient to obtain provisional approval with 3rd party provided later
- Provisional price should be acceptable to begin with EWT, provided that there is retrospective adjustment to full price when DOC and FDP are approved later.
- Incremental production – all production should qualify for incentive price to encourage investment.
- Marginal field definition – does this apply only to new discoveries or also to depleted fields, needs clarity?
- Mining leases – conversion to DPL permits access to current prices and incentives but company loses benefits of ownership of facilities.

- PCA Article 28 refers to arbitration under ICSID Rules and only if ICSID declines jurisdiction then under ICC Rules. This applies also under the model JOA. ICSID is not appropriate.
- Company should not have liability for the production bonus while owned by GOP.
- Renewals and conversion to later rules (?)
- Relinquishment – where a block straddles two Provinces and two Provincial holding companies are involved it is unreasonable that one can use voting power to block work on the other side of the border because it wants more work on its own side.
- Deadlock under JOA among partners – needs attention.
- Offshore projects – challenge of two jurisdictions operating on one side of the territorial limit and only one on the other.
- *[subset of the question over one or two regulators]*
- Provincial regulation – we already have the CCI – what about creating a Council of Common Petroleum Interests?
- Exploration within lease area – Rule 65 – third party may get licence for maximum period and then new lease for 25 years– what period of extension is given to incumbent if it matches terms?
- Extensions beyond 25+5 years should not require automatic payment of additional 15% which ignores cost of additional investment.
- 18th Amendment has created an imbalance of treatment among Provinces – some are using influence to prevent gas reaching Provinces where it is needed.
- Extensions to exploration phase – experiencing difficulty in obtaining approvals
- Rents – rents under 2012 Policy are actually lower than rents under earlier rules after indexation.
- Regulator making agreement to increased levels of rent a condition of extensions which is not permitted by rules but some companies are paying these simply to get extensions. This is a big issue for the company.
- Extension of discovery outside licence area – Rule 22(8). DGPC can revise co-ordinates but not clear what needs to be disclosed to prove this (Why 10%, remove limit)?
- Item – 14 Flaring – Rule 24(3) restricts DGPC approving flaring for more than 30 days and then only on condition of distance from infrastructure and this needs more flexibility.
- General point – DGPC has no geological and geophysical capability.
- CSR – *[same issues as others have expressed in relation to burden of performing to local satisfaction – preference to pay cash and leave performance to local authorities]*

COMPANY F:

2012 Policy: Conversion regime is still awaited: Table

Tight Gas: No Rules

Supplemental application is in place for a field. 1986 Rules (90 days Vs 1yr – 25 years VS 30 years)

Marginal: Guidelines

- Capacity / Capability
- Depletion allowance- 15% of WH value
- Well commencement- deemed approval
- DoC / FDP
- Flare Gas- Penalty – a field's EWT, extension not given, waiting on DoC approval.
- CSR- Optional giving money to DCO
- No issue on "Local" definition.
- Training Funds
  - XYZ Mining Lease was 30+30 years. Lease period expiring before loan period, solution was to go to 1986 Rules (20 years)
- Does new discovery in old lease get separate award period for production.
- Relinquishment 30% for 30%
- Transfer of commitment - GoP wants same JV to commit.
- Penalty: Any days
- Dispute resolution
- FM- not given then why is it there?
  Companies should be allowed related benefit like extension for relevant period.

COMPANY G:

2012 Policy

- Revocation
- Penalty
- Appellate Forum
- Unitization
  - Improve this authority
  - Clarity on when will this trigger

Low BTU

- No Rules yet

Tight Gas

- No Rules
- 40% over 2009 Policy Price almost same as 2012 Policy Price. Should be reviewed further as incentive is reduced /gone
- Can be quickly developed

Marginal

- Define, needs clarity. There is inconsistency / contradictions

General

- Federal/Provincial
  - Dual window operation not desirable. One regulator!

Input to be sent by company later:

- 2012 Policy and 2013 Rules
- Tight Gas
- Marginal – deficiencies
- Low Btu – deficiencies
- Documents / Templates in well commencement etc. + list of deemed approval etc.
- Relinquishment
- Unitization suggestion
- Sample of issues

COMPANY H:

- Since 2004 there has been a linkage to international pricing but each policy has been replaced too quickly. Will the 2012 endure or also be replaced?
- However prices being fixed for existing lease holders, under old policies, is a disincentive for them to conduct new exploration activity.
- Item-8 Real problem is with implementation by DGPC – there is a lack of competence and understanding and they need a change of mind set.
- Some of our problems remain unresolved even after five years.
- We have suffered discrimination – provisions of Article 13.8 were introduced to favour one foreign company in relation to gas surplus to their commitment.
- We however have waited for years for a Supplemental Agreement which will allow us to rely on this provision.
- As a consequence of unfair treatment we are now expanding outside Pakistan.
- We made a discovery of gas and condensate and requested approval of our declaration of commerciality and classification of the field as marginal – but there is silence.
- Another example – we completed drilling of a well and have had no response to submitting results.
- We believe the 2012 Policy was in part designed to deny benefits to our company.
- DGPC is delaying approval of surrender of our interest in small marginal discovery
- We have had similar experience in relation to a low BTU field.

- We have had lengthy meetings with DGPC and DG Gas but there is no movement on open issues. No one has accused us of deficiency in our paperwork and we have no meeting minutes on which to rely.
- Current allocation system of commitments to gas utilities is unfair and should be relaxed to allow producers to sell up to 50% of production to commercial third parties.
- Import duties on equipment and machinery should be zero during exploration and development phases.
- Social and training obligations should be removed during exploration as there is no long term commitment at that point – but GoP could charge token lump sum as part of signature bonus to cover this.
- G+G data should be available free of any charge other than copying costs and should be available in the public domain after three years.
- All companies including state owned companies should have the same obligation to provide performance guarantees – which could also be corporate guarantees.
- Work units need to be reviewed to include wider range of work types.
- Policies need to be attractive and the regulator needs to emerge as a facilitator rather than obstruction. Consider separating DGPC from GOP in some way – established by law but autonomous to attract professionals with experience.
- We need a concept of deemed approval to overcome the excessive delays which are delaying activity.
- An effective appeal process is needed to avoid the courts or arbitration – possibly comparable to the Tax Ombudsman.
- We think that the ombudsman could also determine disputes between field partners
- Discrimination in treatment of companies is evident in DGPC giving similar approvals to different companies and then treating them differently when it comes to formalising in documents.
- *[also suggestion that there is different treatment in notifying gas prices]*

Meeting with PPEPCA:

Issues List:

- Pricing / 10%
- Conversion
- Provincial Holding
- Index Rent (Extensions have been stopped). Legal view being sent.
- Third-Party access
- Appeal Forum- Federal Ombudsman!

General

- Definition of Exploratory effort changed, Cut off
- Policy price reversed after amendment in 2013 for earlier periods. 2013 Amendment list shared with PPEPCA.
- Other than 2001 Policy, no confidence in subsequent as they never got implemented despite requests for conversion.

- Supplemental is still awaited.
- Never sure if they will get the offered price.
- Approvals for ATA/TARs:
  - Difficulty in scheduling, better co-ordination needed, shut downs getting delayed.
- Lease rental indexation Pro-active request
- Training
- Tight Gas Need clarity on Federal/Provincial requirement. Want one window.
- Organizational model discussed during 2009 Policy, still awaited
- GOP using National Cos to influence JVs to tow GoP line. Not on merit but GoP intent. This is detrimental to minority stakeholders.
- JOA- include conflict of interest clause (on commercial aspects).
- No/low protection under JOA to smaller WIOs.
- Subsequent amendments in JOA to be done between partners W/O GOP involvement.
- Exploration activity/timing: leniency requested but with consistency across board
- Clarity deliberately missing?
- NAB aspect brings insecurity for regulator when taking decisions
- Capacity building. None available. Use the Indian example.
- Is financial impact of new policy determined at MPNR.
  - Planning commission or industry tie-up missing
- 3rd Party gas sale hampered
- Mistrust - acceptance of framework.
- Model PCA- local company definition
- Policy Ok,   PCA translation not Ok.
- How will GOP clear conversion back-log for 2007 & 2009?
- Differential continues to build.
- Short fuse requests not ok.
- CMS- Concession Management System to be re-activated
- PCA ⟶ JOA tied to it (recommend it be delinked)
- Employment plan in old concession- to be provided each year
  - GOP issuing notices on this.

Tight Gas: Price to low

General

- Regulator chairing meetings - remove this requirement

Meeting with DGPC for input on Policy/Rules

- Explanation not given by regulator to companies.
- 10% Incremental production
  - What should be the base
  - Is conversion required in to 2012 policy to attract this incentive.
  - Evergreen or not

  - Clarity on Sale or production
  - What to do if FDP comparison is not available
- Development of Economic model mutually agreed with industry
- Penalties could be in the following areas:
  - No Permissions obtained for well commencement, abandonment,
  - Production without lease
  - Drilling in Expired lease
  - Rentals not paid, or not paid on time
  - Late application for extensions
  - Sitting on lease after 90 days of non-production. Operator should surrender.
    - Operator to pay daily or weekly or token penalty.
  - Delay in execution of financial obligations
- Exploration period.
  - Extension beyond first one where additional work commitment % is given should have some financial impact to JV if it is delayed.
- Over regulation?
- CMS – timely info should be received
- Job for locals – clarity on expectation response
- Senate questions delayed from Companies/PPEPCA members. What should be the consequence?
- New bid round – what additional things to do.
  - Add experts
- Issue regarding payment of production bonus where we have more than once discovery in an area and the production bonus has already been paid to only one district. The districts with subsequent discoveries are then deprived of the benefits of the production bonus. Need to have a mechanism for better allocation in such cases.